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BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	
	:	Docket No. R-2025-3054394
Citizens' Electric Company of Lewisburg, PA	:	
	:	

DIRECT TESTIMONY OF BRETT NOLT ON BEHALF OF KELLY ROAD SOLAR, LLC, LANCASTER AVENUE SOLAR, LLC, AND TWILIGHT RENEWABLES, LLC

Solar Projects' Statement No. 1
July 15, 2025

INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. I am Brett Nolt, and I reside at 23 Snyder Hill Road, Lititz, PA 17543.

Q. BY WHOM ARE YOU EMPLOYED AND WHAT IS YOUR JOB TITLE?

A. I am CEO and owner of Twilight Renewables.

Q. WHAT IS YOUR RELATIONSHIP TO KELLY ROAD SOLAR AND LANCASTER AVENUE SOLAR?

A. I am the owner of Kelly Road Solar LLC, as well as the EPC contractor for the Lancaster Avenue Solar LLC Project.

Q. CAN YOU PLEASE DESCRIBE WHAT YOUR COMPANY DOES?

A. Twilight Renewables is a solar construction contractor that I own. I also originate and develop solar projects for personal ownership outside of Twilight Renewables.

Q. HOW MANY SOLAR PROJECTS HAVE YOU DEVELOPED IN THE CITIZENS OF LEWISBURG TERRITORY?

A. Twilight has developed 6 rooftop solar projects in Citizens Territory:

- (2) solar projects that are currently in operation (180kWAC, and 360kWAC).
- (2) projects currently under construction (360kW & 360kW).
- (2) projects that are currently in the development process to be constructed late 2025/ early 2026 (480kW & 480kW).

Q. WHEN YOU SAY ROOFTOP, DO YOU MEAN RESIDENTIAL ROOFTOP OR COMMERCIAL ROOFTOP?

A. Commercial rooftops, specifically barns, used for poultry operations.

Q. WHAT IS THE OUTPUT OF THE OPERATING PROJECTS?

A. The 6 projects combined are rated at 2.22MW AC and produce roughly 4,100,500 kWh a year.

Q. WHEN YOU CONSTRUCTED THE OPERATING PROJECTS WAS THERE ANY COMMUNICATION WITH CITIZENS THAT SUGGESTED THAT CITIZENS WOULD BE ALTERING ITS METHODOLOGY FOR CHARGING CUSTOMERS OF YOUR SIZE?

A. No.

Q. WHEN DID YOU FIRST LEARN OF THE PROPOSED CHANGES TO CITIZEN'S TARIFF?

A. I received an email from Patrick Anderson, senior director of engineering and operations, that notified me of this proposed change on Friday 5/16/2025.

Q. WERE YOU IN A POSITION TO ADJUST YOUR PLANS IN RESPONSE TO THE PROPOSED CHANGES?

A. No. The 50% down payment for the $160,000 in grid upgrades to accommodate the (2) projects currently under construction were paid on 3/31/2025 and 4/28/2025. Once the upgrades are paid for, it signals that the customer is at a point where they cannot "turn back", as the construction contract is signed, and the grid upgrade costs are committed to and Citizens has begun construction. The (2) projects that are currently under development

were submitted on 5/5/2025 and 5/7/2025, and the down payment for grid upgrades for (1) of these was paid on 7/11/2025.

Q. CAN YOU EXPLAIN WHAT CITIZENS HAS PROPOSED WITH REGARDS TO CUSTOMER GENERATORS OF YOUR SIZE?

A. First, Citizens has changed the definition of billing demand. I provide two examples of the impact below.

Q. WHAT ARE THE EFFECTS ON NET METERED SOLAR PROJECTS OVER 400KW THAT PRIMARILY PROVIDE POWER FOR OFFSITE USAGE (EITHER VIRTUAL NET METERING FROM A CUSTOMER SITE, TO A DIFFERENT SITE OPERATED BY THAT SAME CUSTOMER DUE TO SITING CONSTRAINTS, OR SIMPLY SELLING POWER TO CITIZENS) IN THE GLP-1 RATE CLASS:

- The tariff will institute a new demand charge for power being sent to the grid and will increase distribution costs for a 480kW (933,000 kWh/yr) generator from $264/year to $26,000/year. This increase is equivalent to 2.787 cents per kWh of cost, which is a >9700% increase in rates that impacts only generators, with no demonstration of increased costs.
- The tariff would immediately re-classify any solar project rated over 400kWAC from GSSR-1 (a retail rate averaging 8.565 cents/ kWh the last 10 years) down to GSSR-2 (a wholesale LMP rate of and average of 3.238 cents per kWh). From an operational perspective, based on data from 5/18/24 - 5/18/25, using a PA solar array overlaid to LMP pricing. The energy revenue will decrease by 62% .

- This combination of decrease in revenue and increase in cost will provide net a revenue for a generator of this size of .451 cents per kWh or $4,207.83/year for the electricity they produce.
- When taking into consideration the fact that a 734kWDC/480kWAC Solar system costs roughly $1,285,200 upfront with $6,600 of annual operating costs (maintenance & insurance), plus 90% financing at 7% interest amortized over 25 years, the yearly payments and operating cost for a 480kWAC System owner are $104,702, compared to $32,207 in income.

Q. WHAT ARE THE EFFECTS ON COMMERCIAL NET METERED SOLAR PROJECTS UNDER 400KW THAT ARE DESIGNED TO OFFSET 95% OF ONSITE USAGE IN GLP-1 RATE CLASS?

A. The tariff will institute a new demand charge for power being sent to the grid that will be approximately 126% higher than the current tariff. The rate impact will vary on a case-by-case basis, depending on the demand charge being paid before solar was installed. (See Exhibit BN-1 (Shelmar Acres)). This Exhibit is a case study on an operational solar array. In this example, an agricultural operation that uses roughly 253,000kWh annually and has an average monthly demand of 58kW. To offset 95% off the usage (240,000kWh), a 204kWDC/146kWAC solar system is required to be installed. So instead of paying distribution charges for 58kW of demand without solar, they now will pay distribution charges for 146kW. Instead of paying $3,120/year for demand charges, this customer now is paying $7,908/year. This represents a 153% increase in cost for the customer if the customer decides to offset their own usage with solar. Equivalent to 1.995 Cents per kWh

of increased cost. Unfortunately, this equation changed after the owner of Lancaster Avenue Solar LLC invested in a solar system.

This increase in cost will net the generator 6.57 cents per kWh (10 year price to compare average of 8.565 cents/kWh – 1.995 Cents of distribution charges) or $15,768/year in revenue for electricity.

A 204kWDC/146.5kWAC Solar system costs roughly $357,000 upfront with $800 of annual operating costs (maintenance & insurance). With 90% financing at 7% interest amortized over 25 years, produces yearly payments and operating cost for a 146kWAC System owner of $29,050. Compared to $22,968 in income. It is generally understood that solar impacts peak demand of commercial customers by 0-10%, meaning that under the existing tariffs, customers are already paying their fair share.

Q. WHAT WILL BE THE IMPACT OF THESE CHANGES?

A. In summary, based on the above financial picture in both examples, this tariff will ensure no solar of this type over 400kW will get built in this territory and will cause immediate and irreparable financial harm to solar arrays of this type placed in service before this tariff change, if not grandfathered. Customers with commercial systems below 400kW that are offsetting usage will be unable to adequately service debt payments as well due to the 153% increase in distribution costs.

Q. HOW ARE DISTRIBUTION CHARGES CALCULATED PRESENTLY?

A. Calculated solely based on what customers use from the grid.

Q. HOW EXACTLY HAS CITIZENS PROPOSED TO CALCULATE DISTRIBUTION CHARGES MOVING FORWARD?

A. Distribution charges will be calculated on either what customer uses from the grid, or what the customer provides to the grid, even at times of extreme demand when distributed generation is helping grid congestion. These charges will be based on demand, kW, not usage, kWh. And since the company is proposing to charge distribution based solely on kW, generation will not offset any distribution charges.

Q. WHAT PROCUREMENT CLASS ARE YOUR PROJECTS SITUATED IN PRESENTLY?

A. Under the current tariff, all projects would be in GSSR-1, because demand (as it is currently defined) for 5 of the 6 projects are essentially 0. Far from the 400kW threshold requiring customers to go to GSSR-2.

Q. EXPLAIN HOW CITIZENS PROPOSES TO CHANGE THE QUALIFICATIONS FOR THOSE PROCUREMENT CLASSES?

A. Rate classes are structured around the amount of demand needed at your site, historically power used at your site. Redefining demand puts a 480kW solar array in the same class as a large 480kW demand, a manufacturing plant for example, even though there are major differences between the two, with the solar array being a lot more flexible with grid support functions, and the ability to go offline immediately.

Q. WHAT WILL THE CONSEQUENCES BE FOR YOUR PROJECT FROM THE PROPOSED CHANGES TO THE GSSR I AND GSSR II PROCUREMENT CLASSES?

A. I will not be able to service the debt on the project and I will suffer irreparable harm.

Q. HOW IS THE RATE THAT CUSTOMERS WILL BE CHARGED FOR ENERGY IN THE GSSR 2 TO BE CALCULATED?

A. Hourly RTP Energy Charge (This is the LMP) will include the following:

- Capacity Charge
- Transmission Charge
- RTEP Charge
- Administrative Charge (this is the costs incurred by the company and its wholesale supplier to manage energy procurement and delivery)
- Gross Receipts Tax

Q. WILL THIS METHODOLOGY BE THE SAME METHODOLOGY APPLIED TO CUSTOMERS WHO GENERATE ENERGY IN EXCESS OF WHAT THAN THEY CONSUME IN A YEAR?

A. No, customer generators will be paid only at the LMP for excess generation.

Q. HOW VOLATILE IS THE PJM LMP PRICE MECHANISM?

A. Extremely volatile.

Q. IS THE LMP RATE A WHOLESALE RATE?

A. Yes.

Q. DOES THE LMP RATE SOMETIMES FALL BELOW 0?

A. Yes.

Q. IS THE RATE THAT WILL BE APPLIED TO EXCESS GENERATION FROM ONE OF YOUR PROJECTS BE THE SAME RATE IN EACH HOUR THAT WILL BE CHARGED TO OTHER GSSR II CUSTOMERS THAT ONLY CONSUME ELECTRICITY?

A. No, because LMP is the only metric being used for reimbursement. GSSR II customers that consume pay for transmission, capacity etc. in addition to LMP.

Q. DOES LMP RATE VARY EVERY HOUR?

A. Yes

Q. HAS CITIZENS PROPOSED TO ALLOW CUSTOMER GENERATORS TO CHOOSE WHETHER TO BE ON THIS VARIABLE RATE?

A. No, if the system is over 400kWAC, you are forced into GSSR-2.

Q. DOES THE LMP RATE CHANGE MORE FREQUENTLY THAN QUARTERLY?

A. Yes.

Q. EXPLAIN HOW DEMAND CHARGES ARE CALCULATED PRESENTLY?

A. Highest electrical usage of any 15-minute period in a billing month (in kW)

Q. EXPLAIN HOW CITIZENS HAS PROPOSED TO CALCULATE DEMAND CHARGES IN THE FUTURE?

A. Calculated to reflect the customer "use of the distribution system", which will be the greater of Gross generator Rating (kW AC) as stated in the generators interconnection application,

or the maximum demand of the customer during any 15-minute period during the current month. This means that for every generator, their demand is based on the nameplate capacity of the system, which will always be greater than actual maximum demand.

Q. HAS CITIZENS PROPOSED TO INCREASE DEMAND CHARGES FOR CUSTOMER GENERATORS OR OTHER COMMERCIAL CUSTOMER RATE CLASSES?

A. GLP-1 is going up from $3.74/KW to $4.52/KW for all traditional customers, representing a 20% increase. Customer Generators are hit with a 153%-9,700% increase depending on the situation.

Q. IS IT TRUE THAT DEMAND CHARGES ARE BASED ON KW'S OR ON DEMAND RATHER THAN KWH'S WHICH ARE BASED ON ENERGY FLOW?

A. Correct.

Q. HAS CITIZENS PRESENTED ANY DATA TO DEMONSTRATE THAT THERE ARE ADDITIONAL COSTS THAT CUSTOMER GENERATORS IMPOSE ON THE DISTRIBUTION SYTEM, LET ALONE COSTS THAT SUPPORT AN INCREASE 50 TIMES THAT OF CONSUMING CUSTOMERS?

A. No. Not a single witness has offered any data to demonstrate any basis for that claim, it is pure conjecture. **(**See Exhibit BN-2; Citizens' Electric of Lewisburg's response to Solar Project's Set I, No. 14). It is clear that there is no hard data to confirm Citizen's allegations of harm.

Q. **DO YOU HAVE ANYTHING FURTHER TO ADD AT THIS TIME**?

A. No, and this concludes my direct testimony.

EXHIBIT BN-2

SP-I-14

With regard to Mr. Johnson's statement at page 8, lines 5-8 of Citizens' Statement No. 4, that the introduction of net metering will cause a 5,000,000 kWh reduction in Citizens' sales revenue, explain in detail the cause and effect that Mr. Johnson anticipates.

a. Provide all documents consulted by Mr. Johnson to form his conclusion.
b. Provide all facts relied upon by Mr. Johnson as a basis for his conclusion.

Response Provided By:
Nathan Johnson, President & CEO, Citizens' Electric Company

Date: June 26, 2025

Response:

The Company's projection that approximately 5,000,000 kWh would be lost from the 2022 Rate Case to FPFTY 2026 does not claim that the entire 5,000,000 kWh loss is directly and solely due to net metering, but rather that net metering and energy efficiency efforts are notable contributors to the loss. See the attachment titled SP-I-14 Attachment A for a calculation of kWh consumption reductions by new net-metered customer-generators from 2022 through 2024. This analysis shows approximately 2,000,000 kWh lost to net-metered generation during this time. At the current rate of development, the Company expects approximately 1,000,000 kWh in additional offset annually, which would result approximately 4,000,000 kWh lost to net-metered generation by FPFTY 2026, as in indicated in Statement No. 4.

PPL Demand Data 580 Colebrook Road, Mount Joy PA 17552

EXHIBIT BN-1

From	To	KWH Delivered Usage	Pk KW 3P Usage
02/09/2022	03/10/2022	8800	33.2
01/11/2022	02/09/2022	13400	43.2
12/09/2021	01/11/2022	19400	49.5
11/09/2021	12/09/2021	15200	45.7
10/11/2021	11/09/2021	16000	66.5
09/10/2021	10/11/2021	21300	58.9
08/11/2021	09/10/2021	24800	63.3
07/13/2021	08/11/2021	30700	68.5
06/11/2021	07/13/2021	43000	77.6
05/12/2021	06/11/2021	34800	80
04/13/2021	05/12/2021	21300	72.9
03/12/2021	04/13/2021	15500	61.8
02/10/2021	03/12/2021	10500	43.9
01/11/2021	02/10/2021	20200	52.7
12/09/2020	01/11/2021	11000	34.2
11/09/2020	12/09/2020	12000	61.8
10/09/2020	11/09/2020	24500	75.3
09/09/2020	10/09/2020	29700	80.5
08/10/2020	09/09/2020	34700	79.4
07/09/2020	08/10/2020	34400	74.1
06/09/2020	07/09/2020	24100	67.2
05/08/2020	06/09/2020	20500	58.4
04/08/2020	05/08/2020	16200	59.3
03/10/2020	04/08/2020	20500	68.3
02/07/2020	03/10/2020	19700	61.3
01/09/2020	02/07/2020	15200	53.5
12/09/2019	01/09/2020	12500	42.1
11/07/2019	12/09/2019	12500	40.3
10/09/2019	11/07/2019	16500	46.2
09/09/2019	10/09/2019	29100	70.1
08/08/2019	09/09/2019	40300	75.6
07/10/2019	08/08/2019	38200	79.5
06/10/2019	07/10/2019	33500	75.6
05/09/2019	06/10/2019	23900	68.7
04/08/2019	05/09/2019	13300	45.1
03/08/2019	04/08/2019	19500	48.1
02/07/2019	03/08/2019	11500	30.7
01/09/2019	02/07/2019	15500	46.6
12/06/2018	01/09/2019	21600	49.7
11/06/2018	12/06/2018	16900	43.6
10/08/2018	11/06/2018	17100	60.7
09/07/2018	10/08/2018	21400	64.1
08/07/2018	09/07/2018	28500	64.2
07/09/2018	08/07/2018	21300	50.6
06/07/2018	07/09/2018	27300	52.1
05/08/2018	06/07/2018	22100	51.2
04/09/2018	05/08/2018	14400	48.5
03/08/2018	04/09/2018	12300	38.2
02/06/2018	03/08/2018	9800	38
Monthly AVG		21151.02	57.56

Business Use

Yearly AVG		253812.24	

Twilight Renewables Analysis

Site Usage/Demand No Solar

Average Monthly kWh Consumption For 34 Month period :	21,151
Average Yearly kWh Consumption For 34 Month period :	253,812
Average Monthly kW Usage Demand For 34 Month period:	57.56

Solar Array Specs

DC Rating (kW)	204.7
AC Rating (kW)	145.9
Annual Production Year One (kWh)	240,136
Percentage Offset	94.61%

EXHIBIT BN-1

Current Tariff with 95% Solar Offset

Current Distribution Demand Rate for GLP-1	4.52
Monthly Usage Demand kW Per Month	51.81
Annual Projected GLP-1 Distribution Charge:	$ 234.16

Proposed Tariff with 95% Solar Offset

Current Distribution Demand Rate for GLP-1	4.52
Monthly Solar Production Demand kW Per Month	117
Annual Projected GLP-1 Distribution Charge:	$ 528.84

Proposed Tariff Cost Increase with 95% Solar Offset	$ 294.68
Proposed Tariff Cost as a Percentage	126%

Solution (Future Projects):

Option #1: Reduce the tariff distribution rate by 55% to $2/kW for all net metered systems (both grid

Option #2: Change back the billed demand definition since 100% usage net metered solar has very l
This option is preferred due to the fact that a customer that only has a demand of 200kW
Language will need to be added to encompass systems that produce >200% of usage (gr

kWh
kWh
kW

kW
kW
kWh

/kW Demand (Defined as Consumption)
(This assumes a 10% solar impact on demand due to intermittency)

/kW Demand (Defined as Bidirectional Grid Use)
kW (assumes solar array is operating at full rating of 145.9kW, coupled with a minimum monthly real tir

supply and usage customers), to keep costs neutral for customers with/without solar and have everyone
ittle electric demand impact.
normally will need a >400 kW Solar Array to offset 100% of their usage, and then their account will get
id supply) will need to pay $2/kW.

Business Use

kicked into time of use, which adds a lot of complexity to Net Metering, and are harder to educate custo

mers and banks on.

PPL Demand Data 580 Colebrook Road, Mount Joy PA 17552

EXHIBIT BN-1

From	To	KWH Delivered Usage	Pk KW 3P Usage
02/09/2022	03/10/2022	8800	33.2
01/11/2022	02/09/2022	13400	43.2
12/09/2021	01/11/2022	19400	49.5
11/09/2021	12/09/2021	15200	45.7
10/11/2021	11/09/2021	16000	66.5
09/10/2021	10/11/2021	21300	58.9
08/11/2021	09/10/2021	24800	63.3
07/13/2021	08/11/2021	30700	68.5
06/11/2021	07/13/2021	43000	77.6
05/12/2021	06/11/2021	34800	80
04/13/2021	05/12/2021	21300	72.9
03/12/2021	04/13/2021	15500	61.8
02/10/2021	03/12/2021	10500	43.9
01/11/2021	02/10/2021	20200	52.7
12/09/2020	01/11/2021	11000	34.2
11/09/2020	12/09/2020	12000	61.8
10/09/2020	11/09/2020	24500	75.3
09/09/2020	10/09/2020	29700	80.5
08/10/2020	09/09/2020	34700	79.4
07/09/2020	08/10/2020	34400	74.1
06/09/2020	07/09/2020	24100	67.2
05/08/2020	06/09/2020	20500	58.4
04/08/2020	05/08/2020	16200	59.3
03/10/2020	04/08/2020	20500	68.3
02/07/2020	03/10/2020	19700	61.3
01/09/2020	02/07/2020	15200	53.5
12/09/2019	01/09/2020	12500	42.1
11/07/2019	12/09/2019	12500	40.3
10/09/2019	11/07/2019	16500	46.2
09/09/2019	10/09/2019	29100	70.1
08/08/2019	09/09/2019	40300	75.6
07/10/2019	08/08/2019	38200	79.5
06/10/2019	07/10/2019	33500	75.6
05/09/2019	06/10/2019	23900	68.7
04/08/2019	05/09/2019	13300	45.1
03/08/2019	04/08/2019	19500	48.1
02/07/2019	03/08/2019	11500	30.7
01/09/2019	02/07/2019	15500	46.6
12/06/2018	01/09/2019	21600	49.7
11/06/2018	12/06/2018	16900	43.6
10/08/2018	11/06/2018	17100	60.7
09/07/2018	10/08/2018	21400	64.1
08/07/2018	09/07/2018	28500	64.2
07/09/2018	08/07/2018	21300	50.6
06/07/2018	07/09/2018	27300	52.1
05/08/2018	06/07/2018	22100	51.2
04/09/2018	05/08/2018	14400	48.5
03/08/2018	04/09/2018	12300	38.2
02/06/2018	03/08/2018	9800	38
Monthly AVG		21151.02	57.56

Business Use

Yearly AVG		253812.24	

Twilight Renewables Analysis

Site Usage/Demand No Solar

Average Monthly kWh Consumption For 34 Month period :	21,151
Average Yearly kWh Consumption For 34 Month period :	253,812
Average Monthly kW Usage Demand For 34 Month period:	57.56

Solar Array Specs

DC Rating (kW)	204.7
AC Rating (kW)	145.9
Annual Production Year One (kWh)	240,136
Percentage Offset	94.61%

EXHIBIT BN-1

Current Tariff with 95% Solar Offset

Current Distribution Demand Rate for GLP-1	4.52
Monthly Usage Demand kW Per Month	51.81
Annual Projected GLP-1 Distribution Charge:	$ 234.16

Proposed Tariff with 95% Solar Offset

Current Distribution Demand Rate for GLP-1	4.52
Monthly Solar Production Demand kW Per Month	117
Annual Projected GLP-1 Distribution Charge:	$ 528.84

Proposed Tariff Cost Increase with 95% Solar Offset	$ 294.68
Proposed Tariff Cost as a Percentage	126%

Solution (Future Projects):

Option #1: Reduce the tariff distribution rate by 55% to $2/kW for all net metered systems (both grid

Option #2: Change back the billed demand definition since 100% usage net metered solar has very l
This option is preferred due to the fact that a customer that only has a demand of 200kW
Language will need to be added to encompass systems that produce >200% of usage (gr

kWh
kWh
kW

kW
kW
kWh

/kW Demand (Defined as Consumption)
(This assumes a 10% solar impact on demand due to intermittency)

/kW Demand (Defined as Bidirectional Grid Use)
kW (assumes solar array is operating at full rating of 145.9kW, coupled with a minimum monthly real tir

supply and usage customers), to keep costs neutral for customers with/without solar and have everyone
ittle electric demand impact.
normally will need a >400 kW Solar Array to offset 100% of their usage, and then their account will get
id supply) will need to pay $2/kW.

Business Use

kicked into time of use, which adds a lot of complexity to Net Metering, and are harder to educate custo

mers and banks on.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	
	:	Docket No. R-2025-3054394
Citizens' Electric Company of Lewisburg, PA	:	
	:	

SURREBUTTAL TESTIMONY OF BRETT NOLT ON BEHALF OF KELLY ROAD SOLAR, LLC, LANCASTER AVENUE SOLAR, LLC, AND TWILIGHT RENEWABLES, LLC

Solar Projects' Statement No. 1-SR
August 28, 2025

Q. Please state your name and business address.

A. I am Brett Nolt, and I reside at 23 Snyder Hill Road, Lititz, PA 17543, which is my business address as well.

Q. By whom are you employed and what is your job title?

A. I am CEO and owner of Twilight Renewables

Response to Citizens' Witness Nathan Johnson

Q. In his Rebuttal Testimony at Page 15, Line 9 and 10, Mr. Johnson suggests that paying customer generators at the GSSR-1 PTC would constitute an "unreasonable subsidy", how do you respond?

A. Compliance with the Alternative Energy Portfolio Standards Act of 2004 (which requires compensation for electricity from net metered systems be at the full retail value) should not be construed to be an unreasonable subsidy. This legislated mandate has been in place for over 20 years.

Q. On Page 15, Line 15 of his Rebuttal Testimony, Mr. Johnson admits that "some customer generators" will be charged substantially more for distribution demand, how do you respond?

A. A very common goal desired by customers looking into solar, is to offset 100% of their usage. Such a system fully shields them from long-term electric generation/transmission price volatility. Typically, only when space constraints arise do customers settle for less than 100% offset. In my experience, all non-residential customers for whom I have built

systems, (which produce 100% (+/- 10%) of their electrical usage) see more real-time production demand (kW), than usage demand (kW) during midday hours most days out of the year. Therefore, a very common customer goal of a 100% usage-offsetting solar array will almost always trigger increased demand charges under the proposed Citizens Tariff unless the load is perfectly in sync with generation during peak generation hours. That means that even a system designed only to offset usage will still incur substantial rate increases under Citizens' proposed tariff.

Q. In his Rebuttal Testimony at Page 16, Lines 1-3, Mr. Johnson claims that if a customer with demand already exceeding 400 kW were to install solar to offset a portion of their load, they would see little increase in demand charges. How do you respond?

A. In my experience, almost all businesses I deal with that are in a real-time pricing rate class (over 400kW in Citizen's case) lock into fixed price contracts with an electric generation supplier to fix their costs. They don't want to be subject to real time price volatility. However, electric generation suppliers are not required to offer net metering to customers. All suppliers that I have dealt with that do offer net metering include components in addition to LMP's (the capacity, transmission, etc.). I cannot recall a single supplier that reimburses for excess electricity in an energy year. If the customer produces 110% of their usage in a year (due to business decline, energy efficiency upgrades over time etc.) 10% of the production value cannot be monetized. For such customers, there would be a change. However, it is very common for construction of a solar system to void a supply contract, and return the customer to default utility service, where the value of the solar generation is now limited to only LMP as Mr. Johnson stated, and do not include other components

(capacity, transmission, RTEP, e-factor etc.). This could change their rate significantly. In a situation where the customer is only offsetting less than 50% of their usage with a solar generator and has a relatively normal usage profile, there is a good chance that the usage demand number will still be the demand number utilized for billing under the new tariff, resulting in no excess demand charges.

Q. On page 17 of his Rebuttal Mr. Johnson includes a table. Do you have any comments regarding this table?

A. Per my Exhibit: "*BN-1 Excel Form Corrected with Added Detail for Set III"* the real-world agricultural case study suggests a customer offsetting 95% of their usage, that has an average peak demand of 57kW, would be required to install a 146kW generator that operates close to this rating at least once a month in order to meet its consumption. This result aligns best with row 2 of Mr. Johnson's table "50kW Import, 150 kW Gen GLP-1". The resulting change to that customer is a bill going from $2,108/yr to $7074/yr. This is the most common scenario**.**

Q. On page 18, Lines 18-21 of his Rebuttal, Mr. Johnson criticizes your Exhibit BN-1, how do you respond?

A. The method of calculating demand charges is not flawed. Per the table in BN-1, column 4 indicates "Pk KW 3P Usage." Pk meaning peak. I averaged out the peak demand of every month for 4 years to use in my calculations, not the average. Nonetheless, it is not surprising that my "flawed" method of calculation produced the same result as Mr. Johnson's method.

Q. In his Rebuttal at page 18 lines 21-22, and page 19, lines 1-2, Mr. Johnson criticizes your calculation of the generation rate. How do you respond?

A. See Updated *"Citizens Electric Price to Compare Average"* (**Attached as Exhibit BN - 3**). In the exhibit, I weighted the length of time price each price was in effect. The figures are very similar, and they do not change the findings. The average in my testimony was $.08565/kWh. Weighting by length of time produces a result of $.08361/kWh.

Q. In his Rebuttal on Page 19 lines 6-12, Mr. Johnson suggests that your analysis would have a solar project losing money even without the proposed changes. How do you respond?

A. This example was meant to bring to light existing financial pressure with the current tariff, with debt amortized over almost the entire system's useful life, let alone what is being proposed. Financers and wise investors manage their downside risk. We feel that the 10-year average PTC is a good baseline to conservatively model cashflow for the future, while fully realizing there is upside potential in electric rates, as we have seen in the past 2 years. It is true that $.08XX/kWh power for these types of projects is breakeven in a lot of cases. Therefore, a loss of $1,294 in one year cannot be presumed for 25 years. Hence why the new tariff is an existential issue for customers who built projects under the current tariff but are subject to new tariff rules. If rates were to return to an average $.085/kWh for GSSR-1, and a $.03xxx/kWh's worth of distribution charges are introduced, the customer is under water.

Q. On page 20 of Mr. Johnson's Rebuttal at Lines 1-6, he criticizes your singular use of solar projects in your examples, how do you respond?

A. From Discovery it was learned that all (99) customer generators in Citizens Electric territory are fueled by solar. For that reason, for the purposes of my testimony in this case, I have been using "customer generator" and "solar generator" interchangeably. I understand the confusion and understand that a customer generator fueled by a different source will have different peak demand characteristics, but none of those are yet on Citizens' system.

Q. On page 21 of his Rebuttal Testimony at Lines 13-17, Mr. Johnson addresses your suggestion that such radical changes to the Citizen's tariff, which will financially devastate existing customers, should contain a "grandfathering" provision and not apply to existing customers? How do you respond ?

A. A fundamental definition change, and new methodology for billing customers, with some customers being affected by more than 1000% rate increases is completely out of line and needs to be subject to some sort of grandfathering clause. The Company's "phase-in" of some of the charges is not nearly sufficient considering the life of the assets.

Q. On Page 22 of his Rebuttal at lines 13-26, Mr. Johnson proposes the above-mentioned phase-in. Will this be sufficient to address the harm the changes will cause?

A. All of the systems in service are less than 1 year old and have a 30-year service life. Phasing in from 70%-100% in the first 3 years does not come close to fixing fundamental issues at hand.

Q. In his Rebuttal Testimony at page 23, lines 21-22, Mr. Johnson admits that Citizens has relied entirely on the Commission's decision in the UGI case, a case which is currently under appeal. How do you react?

A. I think that it is reckless to base tariff changes of such magnitude on a case where the issues and outcome are disputed and the courts have yet to address the substance of the appeal.?

Q. In Mr. Johnson's Rebuttal at Page 30, lines 15-21, he suggests that you don't know what size transformer is needed for specific loads. What is your response?

A. On all 4 systems in operation, 100% percent of the service costs were covered by the customer, including wiring and transformers, all of which has a lifespan equal to or greater to the solar array lifespan. Mr. Gorman's table on page 17 line 9 of his rebuttal shows the utility charging $22,000/year or $660,000/system life for a 500kVA service that was paid for, in full, by the customer before the system was active.

Q. Mr. Johnson claims that your argument that your distinction between a manufacturing plant load and a customer generator's production is misplaced, and that solar facilities are non-dispatchable on the Citizens' system, how do you respond (Citizens St. 4-R, page 31, lines 15-16)?

A. Other PA utilities have PUC approval to install DER devices that interface with Inverters for power quality/grid reliability reasons. I would assume Citizens has the regulatory ability to utilize settings in customer supplied inverter equipment to strengthen their grid. Citizens chooses not to utilize those benefits, to the detriment and cost of their customers.

Q. Mr. Johnson's Rebuttal at page 31 Lines 22-23, and page 32, at lines 1-3, criticizes your claim that the proposed compensation method for excess generation artificially diminishes the reimbursement, how do you respond?

A. That fact that billing cycle crediting for excess kWh only happens once a month, and kWh's are monetized only once a year does not change the value of the kWh. It is still calculated hourly, and so remains very volatile. Weighted by solar availability, there is on average a $.05/kWh loss in electric value when a customer is moved from GSSR-1 to GSSR-2. Yearly cashflow constraints of being paid only once per year is not the issue that we are concerned about, it's the value of our product being severely reduced.

Q. On page 32 of his Rebuttal, Mr. Johnson claims that the GSSR-2 rate will be a retail rate, do you agree?

A. No, if it were a retail rate, and not just passing through "several" wholesale costs, it would look like GSSR-1. The law requires "full retail value", not a contrived retail "rate" and what Mr. Johnson is proposing does not pass muster.

Q. In Mr. Johnson's Rebuttal at page 32, line 14, he claims that you incorrectly state that a customer generator's "Gross Generator Capacity will always be greater than actual maximum demand." How do you respond?

A. This statement was directed solely looking at the generator independent of any load. A 400kW rated generator will never read 400kW at the utility metering point. The Generators are not 100% efficient, and there will be a small percentage of line loss leading up to the metering point. Metering will typically read somewhere between 392-399kW.

Q. In his rebuttal at page 32, Lines 18-20, Mr. Johnson again attacks your statements regarding Gross Generator Capacity ("GGC"); how do you respond?

A. The Luke Hoover system that Twilight Renewables installed is a good example of the negative impacts specifically Virtually Net Metered Customers. Under current PA net metering laws, a customer can install a Solar system at one site and offset metered accounts within 2 miles under the same utility account name/operation control. Luke Hoover had a brand-new roof (not available at any other location), and easily accessible 3 phase infrastructure at this location. By design, an oversized system was installed to cover the

farm usage at the site on which the solar was located, and the home farm less than 2 miles away, leaving some margin for solar degradation and future load growth.

Utilizing virtual net metering saves the customer from unnecessary construction costs attributed to interconnecting at multiple different service points. Because most of the land area in Citizen's territory is agricultural, it is very common for a farmer to own several farms with electric services within a 2-mile radius of the "home farm". This was the lowest cost solution for Luke Hoover under the existing tariff. This is very common situation solar contractors run into and is not limited just to my "rationale". The new tariff discriminates against a virtual net metering customers, due to the fact that they have to pay distribution charges equating to roughly $.03/kWh to put power into the grid from the solar site, and then pay distribution charges again at the electric service within a 2-mile radius to bring the power "back in" so to speak. I believe this goes against the very intent of Virtual net metering and net metering in general.

Q. In his Rebuttal on page 34 lines 7 & 8, Mr. Johnson suggests that you "could have" known about the UGI decision in February of this year when the decision was rendered, how do you respond?

A. I am not sure what Mr. Johnson is suggesting, but it is irrelevant to my initial point to suggest that I should have some interest in a PUC decision in a territory where I have no projects and could have known about the UGI decision before I did know about it.

Q. In his Rebuttal at page 34, line 10, Mr. Johnson discusses your not having demanded refunds of payments made to Citizens after learning of this case, how do you respond?

A. This is a ridiculous spin on actual events. Transformers were procured by Citizens for these specific projects, and active line construction was happening by Citizens towards the goal of interconnecting the solar generator in good faith prior to the payments being made. To say I could have requested a return of my deposits on May 15th, leaving citizens with unfinished/unneeded 3-phase line infrastructure, with costs being ultimately paid for by existing ratepayers is absurd.

Q. In his Rebuttal at page 34, line 12, Mr. Johnson claims that you proceeded with a project, even knowing about the changes Citizens was proposing. What is your response?

A. Apart from acknowledging that the proposed Citizens' changes are so arduous that it would seem reasonable to him that I withdraw my projects, I did indeed submit the Fairfield Road Solar Project's 50% utility upgrade down payment, in an effort to establish service at the facility and energize the solar array by the end of the year, prior to this case being decided by the PUC, or the Commonwealth Court's decision on the UGI case. The world does not stop under regulatory uncertainty. Several PA senate bills regarding net metering are introduced every year. To say no development should happen during regulatory uncertainty is absurd. We plan to energize new system under AEPS Law, under the current EDC tariff. Luke Hoover, and the Lancaster Avenue Solar Project were turned on last year and were in operation prior to the UGI default service proceeding. Disputing the fact that they will suffer irreparable harm is ridiculous.

Response to Citizens' Witness Gorman

Q. On page 16 lines 21-23 of his rebuttal testimony, Mr. Gorman claims that both your testimony and that of Mr. Lucas "clearly explain that avoiding distribution charges is a part of the incentive for their projects." How do you respond?

A. My testimony claims that non-residential customers that install systems to cover 100% of their electrical usage (+/-10%) will continue to pay usage demand charges as before. I claim that solar generation will affect usage distribution charges by 0-10% under the current tariff. Avoiding distribution charges is not part of the incentive here. Mr. Gorman is incorrect.

Q. On page 17 of his Rebuttal, at lines 6-7, Mr. Gorman suggests that the company needs the same assets to serve 400kw of load as it does 400 kW of generation – is he correct?

A. No. His answer ignores power quality differences. Power quality can be improved by DER as discussed in my testimony.

Q. In his rebuttal testimony at page 19, lines 12-13, Mr. Gorman suggests that generators will at some point use all of their capacity: is he correct?

A No. A 400kW rated generator will never read 400kW at the utility metering point. The Generators are not 100% efficient, and there will be a small percentage of line loss leading up to the metering point. Metering will typically read somewhere between 392-399kW. If a battery was introduced to limit output to of a 400kW solar generator to 200kW during the day, and exported stored power at night, that is a possibility as well to limit demand on the grid below the rated generator capacity.

Q. Does this conclude you Surrebuttal Testimony?

A. Yes.

Exhibit BN-3

Date Going into Effect	Price (Cents/kWH)	Months under this rate:	B*C (for weighted average calculations)
2/1/2024	0.0987	4	0.3948
12/1/2023	0.1097	2	0.2194
7/1/2023	0.1334	5	0.667
6/1/2023	0.1381	1	0.1381
2/1/2023	0.1343	4	0.5372
1/1/2023	0.1264	1	0.1264
12/1/2022	0.1223	1	0.1223
6/1/2022	0.0937	6	0.5622
3/1/2022	0.074	3	0.222
1/1/2022	0.078	2	0.156
12/1/2021	0.0795	1	0.0795
6/1/2021	0.0698	6	0.4188
2/1/2021	0.0645	4	0.258
12/1/2020	0.0747	2	0.1494
6/1/2020	0.0748	6	0.4488
2/1/2020	0.0759	4	0.3036
12/1/2019	0.0798	2	0.1596
6/1/2019	0.065	6	0.39
2/1/2019	0.0778	4	0.3112
12/1/2018	0.0754	2	0.1508
7/1/2018	0.0716	5	0.358
6/1/2018	0.0705	1	0.0705
2/1/2018	0.0746	4	0.2984
12/1/2017	0.0701	2	0.1402
7/1/2017	0.0696	5	0.348
6/1/2017	0.0665	1	0.0665
12/1/2016	0.0816	6	0.4896
6/1/2016	0.0715	6	0.429
4/1/2016	0.0804	2	0.1608
1/1/2016	0.0799	3	0.2397

	10/1/2015	0.0745	3	0.2235
	7/1/2015	0.0836	3	0.2508
	6/1/2015	0.0772	1	0.0772
	4/1/2015	0.0854	2	0.1708
	1/1/2015	0.082	3	0.246
	10/1/2014	0.0797	3	0.2391
	7/1/2014	0.0957	3	0.2871
	4/1/2014	0.0893	3	0.2679
	2/1/2014	0.0971	2	0.1942
	1/1/2014	0.0795	1	0.0795
Total			125	10.4519
Weighted Average Based on Time:		0.0836152		
Average Based on Line Item: (Regardless of time)		0.0856525		

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	
	:	Docket No. R-2025-3054394
Citizens' Electric Company of Lewisburg, PA	:	
	:	

DIRECT TESTIMONY OF KEVIN LUCAS ON BEHALF OF KELLY ROAD SOLAR, LLC, LANCASTER AVENUE SOLAR, LLC, AND TWILIGHT RENEWABLES, LLC

Solar Projects' Statement No. 2
July 15, 2025

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I. INTRODUCTION AND QUALIFICATIONS

Q1. Please state for the record your name, position, and business address.

A1. My name is Kevin Lucas. I am the Vice President of Policy Analysis at the Solar Energy Industries Association ("SEIA"). My business address is 1425 K St. NW #1000, Washington, DC 20005.

Q2. Please summarize your business and educational background.

A2. I began my employment at SEIA in April 2017 as the Director of Rate Design and since January 2024 have been Vice President of Policy Analysis. SEIA is leading the transformation to a clean energy economy. SEIA works with its 1,200 member companies and other strategic partners to fight for policies that create jobs in every community and shape fair market rules that promote competition and the growth of reliable, low-cost solar power. Founded in 1974, SEIA is a national trade association building a comprehensive vision for the Solar+ Decade through research, education, and advocacy.

During my time at SEIA, I have developed testimony in rate cases on rate design and cost allocation; in integrated resource plans on resource selection and portfolio analysis; worked on net energy metering, virtual power plant, and distributed generation compensation mechanisms; and performed a variety of analyses for internal and external stakeholders.

Before I joined SEIA, I was Vice President of Research for the Alliance to Save Energy ("Alliance") from 2016 to 2017, a DC-based nonprofit focused on promoting technology-neutral, bipartisan policy solutions for energy efficiency in the built environment. In my role at the Alliance, I co-led the Alliance's Rate Design Initiative, a working group that consisted of a broad array of utility companies and energy efficiency products and service providers that sought mutually beneficial rate design solutions. Additionally, I performed general analysis and research related to state and federal policies

that impacted energy efficiency (such as building codes and appliance standards) and domestic and international forecasts of energy productivity.

Prior to my work with the Alliance, I was Division Director of Policy, Planning, and Analysis at the Maryland Energy Administration, the state energy office of Maryland, where I worked between 2010 and 2015. In that role, I oversaw policy development and implementation in areas such as renewable energy, energy efficiency, and greenhouse gas reductions. I developed and presented before the Maryland General Assembly bill analyses and testimony on energy and environmental matters and developed and presented testimony before the Maryland Public Service Commission on numerous regulatory matters.

I received a Master's degree in Business Administration from the Kenan-Flagler Business School at the University of North Carolina, Chapel Hill, with a concentration in Sustainable Enterprise and Entrepreneurship in 2009. I also received a Bachelor of Science in Mechanical Engineering, *cum laude*, from Princeton University in 1998.

Q3. Have you testified previously before the Pennsylvania Public Utility Commission ("Commission")?

A3. No, I have not.

Q4. Have you testified previously before other state utility commissions?

A4. Yes. I have submitted testimony in rate cases, integrated resource plans ("IRP"), utility merger proceedings, and renewable portfolio and energy efficiency resource standards before the Arizona Corporation Commission, the Colorado Public Utilities Commission, the Georgia Public Service Commission, the Illinois Commerce Commission, the Maryland Public Service Commission, the Michigan Public Service Commission, the Public Utility Commission of Nevada, the North Carolina Utilities Commission, the Public

Service Commission of South Carolina, the Public Utility Commission of Texas, and the Virginia State Corporation Commission. My complete CV is attached to my testimony.[1]

Q5. On whose behalf are you submitting testimony?

A5. My testimony is provided on behalf of Kelly Road Solar, LLC, Lancaster Avenue Solar, LLC, and Twilight Renewables, LLC (collectively, the "Solar Projects").

Q6. What is the purpose of your testimony?

A6. I review the application of Citizens' Electric Company of Lewisburg, PA ("Citizens'") in this proceeding. While the focus of my testimony is on this Citizens' proceeding, I also discuss related issues in the now-consolidated application of Wellsboro Electric Company ("Wellsboro") in Docket No. R-2025-3054392. The primary focus of my testimony is the implication of Citizens' and Wellsboro's (collectively, "the Utilities") proposals to change the way small commercial customer-generators would be assigned the GSSR-1 and GSSR-2 rate schedules. I review some of the discovery responses that shed further light on the mechanics of their proposals and the potential impact on their customers.

Q7. Please summarize your findings.

A7. I find the Utilities' proposal to introduce a new concept of Billing Demand based on hypothetical power flows is deeply flawed and recommend that it be rejected. Their proposal to charge customers based not on their actual use of the system but based on hypothetical, idealized use of the system results in unreasonable and unjust rates. Further, the use of Billing Demand could increase the distribution bills of customer-generators more than if they had never installed solar, despite potentially lowering their peak demand during times of higher grid stress. And despite all these negative outcomes, the Utilities propose to apply this definition to all existing and soon-to-be customer-generators, with no legacy customer treatment.

[1] Attachment KL-1, Kevin M. Lucas CV.

I also question the viability of the Utilities' proposal to shift from a kilowatt hour ("kWh")-based net metering rubric to a dollar-based net billing rubric for generation compensation for larger customers. It appears the proposal directly contradicts the underlying Pennsylvania net metering statute both by bifurcating the netting and compensation treatment of generation from distribution and transmission, and by shifting to a net billing construct. While the attorneys in this case will address the legal implications of the Utilities' proposals, I find that the policy implications of this shift are also troubling as they would require medium-sized businesses to take default service under a much more complex tariff that could have significant adverse impacts on their businesses.

Q8. Please summarize your recommendations.

A8. I recommend the Commission reject the Utilities' proposal related to Billing Demand and its use in charging and classifying customers for electricity service. I further recommend the Commission determine whether the proposed shift to a net billing structure for generation compensation comports with Pennsylvania law, but even if it technically does, reject it based on policy reasons.

II. THE UTILITIES' "BILLING DEMAND" PROPOSAL IS HIGHLY UNUSUAL, INAPPROPRIATE, AND FLAWED AND SHOULD BE REJECTED

Q9. What is the purpose of this section of your testimony?

A9. In this section of testimony, I provide an overview of the Utilities' Billing Demand proposal. I discuss several reasons why the definition is flawed and examine its impact on several customer-generators' scenarios. I respond to the Utilities' assertion that the Billing Demand definition is needed to avoid cost shifts to other customers. Finally, I discuss why the expansion of the Billing Demand concept from a different default service docket into distribution ratemaking is inappropriate and why the Utilities' new netting proposal may conflict with Pennsylvania law.

A. Billing Demand Proposal Overview

Q10. Please explain the Billing Demand Proposal advanced by the Utilities.

A10. The Utilities propose to introduce a new Billing Demand definition for use in both distribution rates and for classifying customers into the Default Service Generation Supply Service Rate ("GSSR") schedules. Billing Demand is defined as follows:

> Billing Demand shall reflect the Customer's use of the distribution system, which will be the greater of Gross Generator Rating (kW(AC)) as stated in the generator interconnection application or the maximum demand of the customer during any 15-minute period during the current month.[2]

For customers with distributed generation ("DG"), the Company proposes to use the larger of the net demand (e.g., native load less self-consumed DG energy) and the maximum DG generator rating, even if the latter is not actually attained in a given month. Moreover, the construction of the proposal means that the maximum DG generator rating will act as a permanent, 100% demand ratchet for the customer regardless of how their usage changes over time.

The Utilities also propose to use this new Billing Demand definition to assign non-residential customers to different distribution and Default Service rates. Both Utilities propose to base the non-residential tariff break points on the Billing Demand of a customer, rather than on their actual net usage of the grid. The proposed breakpoints and rates of the two utility's tariffs are shown below in Table 1.[3]

[2] Citizens' Statement No. 4, Direct Testimony and Exhibits of Nathan Johnson at 18. ("Johnson Direct").
[3] Citizens' Tab D, Supplement 172 ("Citizens' Tariff""); Wellsboro Tab D, Supplement 162 ("Wellsboro Tariff").

Table 1 – Non-Residential Customer Tariff Break Points			
	Small	**Medium**	**Large**
Citizens'	**GLP-1**		**GLP-3**
Demand Limits			>= 50 kW
Customer Charge	$21.00		$100.00
$/kW	$4.52		$6.91
$/kWh Flat	$0.01164		
$/kWh per kW			$0.01221 up to 30 kWh/kW
$/kWh additional			$0.00133
Wellsboro	**No. 3**	**No. 4**	**No. 5**
Demand Limits / Voltage	<= 7 kW / Secondary	> 7 kW / Secondary	> 50 kW / Primary
Customer Charge	$16.50	$32.03	$150.00
$/kW		$9.24	$14.00
$/kWh Flat	$0.15758	$0.03357	
$/kWh per kW			$0.02881 up to 130 kWh/kW
$/kWh additional			$0.00182

The Billing Demand will also be used to assign customers into either GSSR-1 or GSSR-2. Customers with a Billing Demand under 400 kilowatt ("kW") will be assigned to the GSSR-1 tariff, while those 400 kW or more will be assigned to the GSSR-2 tariff.[4]

Q11. What arguments are advanced to support this change?

A11. Both Utilities make similar but not identical arguments as to why the proposal is needed. Generally, the Utilities argue:

- Customers should pay for their use of the distribution system, and this use is best measured by either power flow from the utility to the customer or by the maximum amount of power a customer could generate.[5]
- There is not a meaningful difference in planning or utility operations depending on whether a customer imports power from the grid or a customer exports power to the grid.[6]
- The Commission's decision in the recent UGI Utilities, Inc. – Electric Division ("UGI") Default Service Plan proceeding should be extended beyond the power supply context and be used to determine distribution rates.[7]

[4] Citizens' Tariff, GSSR-1 Rider, GSSR-2 Rider.
[5] Johnson Direct at 17, Wellsboro Statement No. 4, Direct Testimony and Exhibits of Byron Farnsworth, Jr. at 23. ("Farnsworth Direct").
[6] Johnson Direct at 17, Farnsworth Direct at 23.
[7] Johnson Direct at 17-18 (discussing *Petition of UGI Utilities, Inc. – Electric Division for Approval of a Default Service Plan for the Period of June 1, 2025 through May 31, 2029, Docket No. P-2004-3049343, et al.)*, Farnsworth Direct at 22.

Q12. Do you agree with the Utilities on these points?

A12. No, I do not. As a primary matter, the Utilities' testimony on these points is very thin, with only a handful of paragraphs dedicated to what would be a seismic shift away from evidence-based cost of service ratemaking principles to impose rate design changes that would have outsized adverse impacts on certain customers. Utilities have the burden of proof in rate cases to show that the rates proposed are just and reasonable,[8] and the lack of detail in the Utilities' filings is very problematic. Taken in total, the proposals advanced by the Utilities are quite radical, and such an extreme proposal would need equivalent levels of support for the Commission to be able to approve it. That has simply not been provided in this case.

Moreover, each point contains a problematic jump in logic that is outside traditional ratemaking practices. The Utilities propose to bill customers not based on their actual demand levels, but on the potential power their generation systems could place on the system even if that value is never attained. It also transfers the Commission's settlement approval regarding power supply rates to its distribution rates, despite the dramatically different regulatory structure that governs these two different areas. I will discuss each of these issues in turn.

B. The Utilities' Proposed Billing Demand Definition is Flawed and Punitive

Q13. What are the issues with the Utilities' Billing Demand definition?

A13. There are three major issues with the proposed definition. First, the Utilities propose to apply the new definition to existing customers with no legacy customer or project treatment (*i.e.*, grandfathering). Second, it is not based on a customer's actual use of the distribution system. Third, it can assign customers to a larger distribution customer class rate or a substantially more complex power supply rate independent of actual usage. The first issue alone is highly problematic, but when coupled with the second and third, it results in a

[8] *See* 66 Pa. C.S. § 315(a).

discriminatory rate that penalizes customers who have or plan to install on-site generating systems to participate in net metering, or behind-the-meter DG ("BTM DG") systems.

Q14. Do the Utilities propose to exempt any customers that currently operate BTM DG systems from the new Billing Demand definition?

A14. No. The Utilities' proposal contains no legacy customer treatment of any kind, meaning that any customer who has already installed is in the process of installing a BTM DG system will immediately be subject to the new definition. This may come with a mandatory change in the customer's distribution rate schedule and default service rate structure. As I will discuss below, there are several major differences between the Utilities' small commercial and large commercial rate schedules that would have sizable bill impacts on customers, independent of the compensation for their exported solar generation.

Q15. In your experience, do changes related to net metering typically occur on a forward-looking basis?

A15. Yes. In almost all cases when policy makers decide to make changes to net metering structures, they do so at a future date and exempt existing customers who have either installed their systems or have reached a certain development milestone such as a signed interconnection agreement. Subjecting a customer who has already made an investment in a BTM DG system to structural financial changes that could not have been reasonably anticipated is, in my view, bad policy. If the Commission decides to approve the Utilities' Billing Demand proposal – which I strongly recommend it does not – it should at a minimum require this change only a prospective basis, starting on a future date certain, while allowing sufficient time for in-development projects to be completed and placed on the current tariff regime.

Q16. Turning to the second issue, how does the proposal ignore a customer's actual use of the system?

A16. The Billing Demand definition is based on the larger of two values: (1) the highest average power usage over any 15-minute period in a month; and (2) the gross generation rating of

a DG system. The former is a conventional method among non-residential customers to determine billing demand, and if the Utilities had based Billing Demand on this value there would be little concern about its appropriateness. However, by taking the gross generation rating of a DG system, which is the maximum amount of power that it could produce independent of load or weather conditions, the Utilities break from convention.

The gross generator rating serves as an upper bound on the energy production from a DG system. It typically only is realized on clear, sunny days during certain months of the year, and then only for a portion of the hours in the middle of the day.[9] In one of the workpapers provided by the Utilities in discovery, a modeled PV rooftop PV system only reached its gross generation rating in 19 hours over the course of a year.[10] In other words, for 99.8% of the year, the system produced less power than its theoretical maximum.

Further, all solar systems degrade slowly over time, meaning that for every year that passes the system will produce slightly less output in similar weather conditions. The Utilities' proposals do not factor this in and, given the gross generation rating is a function of a system's inverter hardware, it will remain fixed for the lifespan of the system even if the system ceases to be able to saturate the power output of its inverters.

Q17. Does the proposed Billing Demand definition reflect the load of a BTM customer-generator?

A17. No, it does not. The Utilities' proposals look at the gross generation rating of the system in isolation. But for a BTM system, the apparent load that a customer-generator places on the grid is a function of both BTM generation and its native load.[11] The Utilities completely ignore this reality, despite providing a workpaper that vividly demonstrated this fact.

Q18. Please describe this workpaper.

[9] Ground-mounted single-axis tracking systems are able to maintain their maximum generation for more hours in day as they can pivot to follow the sun, but the frequency of these maximum generation hours depends on the inverter loading ratio. Fixed-tilt systems common on rooftops do not attain their maximum generation as often.
[10] Ex. KL-2, SP-I-21 Attachment A excerpt. The Utilities modeled a fixed-tilt system with a 1.2 ILR.
[11] The native load is the load that the customer's equipment consumes independent of solar generation.

A18. Citizens' provided a workpaper in discovery that purported to analyze the impact of its proposal on a hypothetical 450 kW_{AC} fixed-tilt photovoltaic ("PV") system on its own, when paired with a roughly 400 kW peak demand customer, and when paired with a roughly 120 kW peak demand customer.[12] That said, the workpaper contained many errors that rendered its results moot and required correction before any reasonable comparison can be made. These errors include:

- **Incorrect modeled system size**. Citizens' discovery response stated they modeled a 450 kW_{AC} system, but the workpaper actually modeled a 412.5 kW_{AC} system due to an improper inverter load ratio ("ILR") assumption.
- **Mismatched solar generation**. The workpaper contained hourly load in Eastern Prevailing Time format, but did not adjust the PVWatts modeled solar generation, which is in Eastern Standard Time.
- **Applies "generic" weather and solar generation to actual metered load**. PVWatts uses a "typical meteorological year" weather to derive solar generation. This approach takes a month's worth of weather from 12 different years and necessarily does not match weather conditions for the actual hourly load data.
- **Hardcoded, incorrect system size in bill calculation**. The workpaper used the incorrect system size in the bill calculation.
- **Incorrect metered demand**. The metered demand for the two customers does not correspond to the hourly load data, the hourly solar generation, or the hourly net load data.[13]
- **Incorrectly copied wrong Customer A metered demand values to Customer B.** The workpaper copied the hardcoded metered demand values from one customer to the other instead of recalculating them from the hourly load information.
- **Customer B is not entirely based on actual data.** Customer B's load from June and July is just a scaled-down version of Customer A. It is unclear whether a customer with a roughly 66% lower load would have the same hourly load pattern as the larger customer during these hot summer months.
- **Incorrectly calculated energy use.** The workpaper references the incorrect value when calculating the kWh per kW energy usage.

[12] Exhibit KL-3, Citizens' response to SP-I-21. The values above are based on the hourly load data as the embedded historic metered demand values do not match the hourly data.

[13] It is possible although unlikely that some of the monthly differences are due to the use of 15-minute peak demand history compared to the hourly integrated load presented in the worksheet. However, the difference for some months is sizable (e.g., the hardcoded value in September is 400 kW compared to a maximum hourly load of 350 kW), and in some months the hardcoded value is smaller than the maximum hourly load (in which case the hardcoded value cannot represent the highest 15-minute billing demand if there is a larger hourly demand in the same month).

- **Incorrectly calculated net energy bank usage.** The workpaper does not correctly net out a month's usage with the banked energy before calculating the energy component of the bill.

Q19. Were you able to correct these issues?

A19. I corrected all of the issues except for the application of the Typical Meteorological Year ("TMY") weather files as 2025 historic weather data is not yet available for the time period the Company analyzed. While this may have a noticeable impact on the overall customer bill if a hot, sunny afternoon where customer load is high is represented by a cool, cloudy afternoon in the TMY data, historic load data during a time when historic weather data was not available at the time submission of this pre-filed testimony.

After correcting these issues, I recomputed annual bills based on two different metrics. The first is based on a conventional definition of billing demand, which is the maximum amount of net power the Utilities deliver to a customer, labeled "Bill on Inflow" below. The second was based on the highest power flow to or from the customer, labeled "Bill on Max Inflow/Outflow" below. This approach is still unconventional and not recommended as it is not reflective of cost-causation principles, but it highlights the difference between billing on actual power flows as opposed to hypothetical ones as the Utilities propose.[14]

Using my counter-analysis, the extreme nature of the Utilities' proposals becomes clear. A customer-generator with significant excess generation would see a massive increase in its bill, going from essentially paying only the fixed customer charge to paying 27 times more under the Utilities' proposal. Customer A, who self-consumes nearly 93% of its solar generation and never had an hour where exported solar exceeded its minimum nighttime load, much less its minimum daytime load, would still see a 25% increase in its distribution bill despite not placing any more demand on the Utilities' systems. And

[14] When applied to shared distribution assets, non-coincident demand charges are not reflective of cost-causation because these assets are designed to share the diversified load of all customers that are being served by them. A customer with a sizable BTM solar generator will likely experience their maximum exported power in the middle of the day in non-summer months, a time when the power grid has spare capacity and the exported power is not causing any marginal cost increases.

Customer B, whose system would be sized to offset 108% of their annual usage, would see more than a 350% increase in their annual distribution bill compared to the current definitions of billing demand.

Table 2 – Bill Comparison

	412.5 kW PV System	Customer A ~400 kW Load	Customer B ~120 kW Load
Citizens' Original Workpaper	$38,514	$42,589	$38,574
Corrected Citizens' Workpaper[15]	$35,405	$39,338	$35,447
Bill on Inflow	$1,200	$31,431	$7,795
% Increase	2,850%	25%	355%
Bill on Max Inflow/Outflow	$32,437	$31,431	$26,920
% Increase	9%	25%	32%

The Bill on Max Inflow/Outflow shows how much the Utilities' proposal to use hypothetical energy flows would impact bills. Given the high degree of self-consumption, Customer A never exports more than 46% of its solar generation to the grid in any given hour. Further, the highest hour of solar export (178 kW) is actually lower than the lowest level of inflow over the entire year (185 kW). In other words, every piece of equipment that is needed to deliver the minimum annual load to this customer – which is about 45% of its peak load – is already able to handle the power flow associated with the maximum export of solar generation. And yet the Utilities' reliance on the gross generator rating would increase this customer's bill by 25%.

Customer B would perform worse on this metric as its solar system is larger relative to its native loads. In this case, billing based on the gross generator rating instead of the maximum power flow to and from the customer would result in a 32% increase in annual distribution bills.

Q20. Please discuss the third reason the Utilities' approach is problematic.

A20. The customers above have peak demands (roughly 400 kW and 120 kW) that are well above the 50 kW threshold of the Utilities' large commercial customer tariffs. But smaller customers who wish to install a BTM PV system that offsets a reasonable fraction of their

[15] As corrected by based on my revisions discussed herein.

annual energy usage could pay outsized demand charges based on power flows that are simply not relevant to cost causation.

Imagine Customer C is a Citizens' customer with a 25-kW peak demand who takes service on the GLP-1 tariff. Under Citizens' proposed rate increase, that customer would face a customer charge of $21 per month and a demand charge of $4.52/kW.[16] If one scaled the peak demand of Customer A to this size, a 50 kW_{AC} PV system would offset about 51% of their annual usage, a reasonably modest amount. Further, the maximum export this customer would have in a year of 36 kW is well below the 50 kW gross generator rating that would establish their Billing Demand.

Q21. What do these changes do to Customer C's distribution bill?

A21. They substantially increase it, even after accounting for the solar generation. Table 3 below shows what Customer C would pay under the GLP-1 tariff with and without solar under the current tariff definitions, and under the GLP-1 tariff with solar under the Utilities' proposal. The Utilities' proposals would increase the total distribution component by 77% compared to what the customer would pay on the GLP-1 tariff under the current definitions, and adding solar would increase the distribution charges by 25% compared to having no solar at all.

Table 3 - 25 kW Load / 50 kW Solar Bill Comparison

	Customer Charge	Demand Charge	Energy Charge	Distribution Total
GLP-1 No Solar	$252	$1,110	$1,680	$3,042
GLP-1 Current	$252	$1,064	$825	$2,141
GLP-1 Proposed	$252	$2,712	$825	$3,789

Q22. The Utilities argue that this is appropriate to avoid any cost shift to other customers. Do you agree?

A22. No. The Utilities' proposals do not just prevent this customer from reducing their distribution bill, it actively increases beyond what they would pay without solar. Their argument is that the loads that Customer C places on the system after installing solar

[16] SEIA takes no position on the revenue requirement and cost allocation proposed by the Company.

somehow increases the cost of providing service to this customer, and if Customer C does not pay more, then other customers will have to make up the difference. But Customer C's peak demand is reduced after installing solar in all non-winter months, with its peak demand falling by as much as 10% in the summer where the grid is under the most strain. Figure 1 below shows the pre- and post-solar peak hourly demands of the customer, showing these persistent demand reductions during the summer months when load on the Company's system is high.[17]

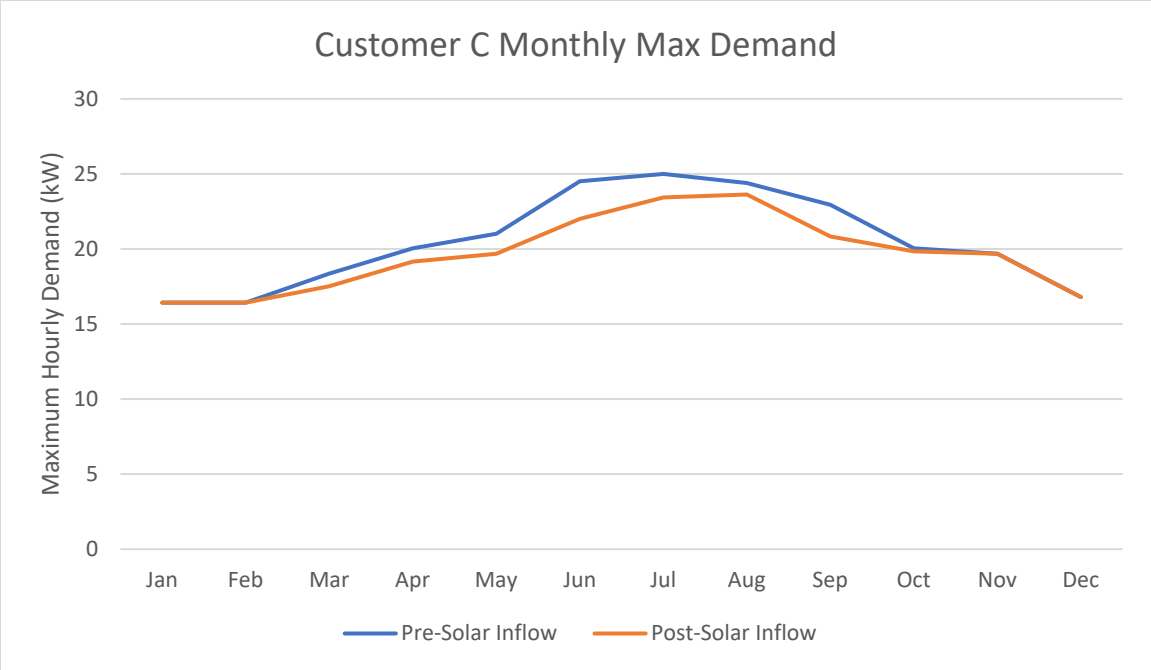

Figure 1 - Customer C Monthly Max Demand

Q23. Does the absolute level of power flow from Customer C to the utility increase after installing solar?

A23. Yes, but only during non-summer months. Figure 2 below adds in the maximum power flow to or from the Utilities' grid. In the early months of the year, there are weekend midday hours when solar generation is high and on-site consumption is low, leading to an

[17] Notably, the summer month with the smallest load reduction is August. In inspecting the TMY weather file used to simulate the solar generation, there was a two-day cloud event that produced very low solar generation. If the weather file and the load files had been date-matched, then this cloud event would likely have also cause a reduction in cooling load, which could have reduced the post-solar peak demand for that month. This temporal mismatching between load and generation is one of the limitations of the Utilities's analysis.

export level of roughly 35 kW that exceeds Customer C's maximum inflow demand during these months. In the summer, Customer C's maximum power flow is set by inflows as the midday solar generation is consumed onsite. In the fall, maximum outflows again surpass maximum inflows as cooling loads fall. And in all cases, the maximum outflow is well below the gross generator rating ("GGR") of 50 kW on which the Utilities propose to base demand charges.

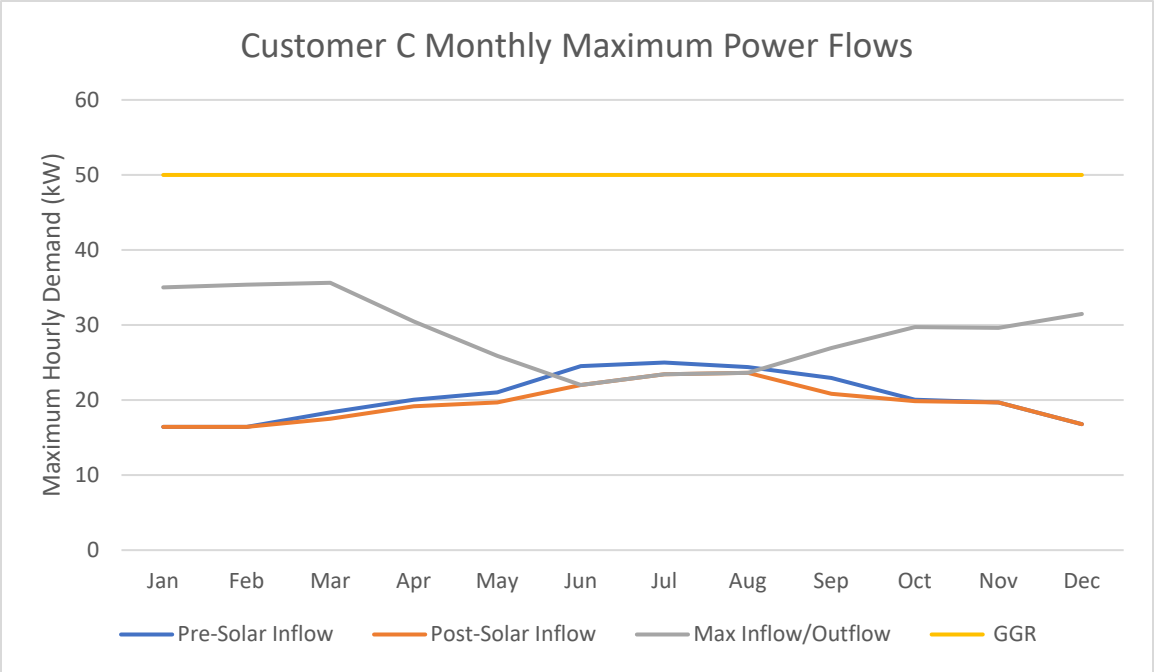

Figure 2 - Customer C Monthly Maximum Power Flows

Q24. Are these increased power flows during the non-summer months problematic for the Utilities?

A24. No. It is important to note that aside from service drops, meters, and line transformers in sparsely-populated areas, very few customers have dedicated distribution equipment that is designed to serve only their load. In fact, the vast majority of the Utilities' distribution rate base is comprised of shared assets such as substations, feeders, and most transformers. These assets are designed to meet the diversified demand of all customers being served by the assets, not the maximum power flows of each individual customer.

Further, the increased outflows in the non-summer months all occur in the middle of the day when the broader distribution grid is experiencing lower loads overall. The maximum outflows occurred between 11 AM and 12 PM three times, between 12 PM and 1 PM five times, and between 1 PM and 2 PM once. By contrast, in non-summer months the Utilities' grids peak in the early morning or late evening, so this marginal increase in midday exported power has no bearing on the aggregate peak load of shared distribution assets.

The one instance in which the increased power flows from Customer C's exported power could be an issue is if Customer C was served by dedicated distribution assets (such as a line transformer or service drop) that cannot handle the new power flows. However, in this instance, Customer C would have been required to pay for an upgrade to these facilities in order to safely interconnect the distributed energy resource ("DER") system in the first place, isolating other distribution customers from the potential cost increase of upsizing these assets.

Q25. Given this, what is the net effect of the Utilities' Billing Demand definition?

A25. The proposal fails on all fronts. It is not fair as it relies on hypothetical power flows that in reality are not realized by customers with BTM solar. It is not based on cost-causation principles as it can, without justification, substantially increase the distribution rates a customer pays even if they do not place loads on the system that increases costs. And it is punitive as it can substantially increase distribution bills for customers who have already installed BTM solar systems.

C. Power Flows from Individual Customers Must Be Analyzed as Part of the Whole

Q26. What is the Utilities' second justification for their proposal?

A26. The second justification is, generally, that the Utilities must plan and operate their grids for maximum power flows whether they are being sent to the customer or being received from the customer.

Q27. Is this assertion technically accurate?

A27. Yes, but it must be taken in the proper context. It is obviously the case that the Utilities must plan for and manage the power flows on the grid, and they have policies and protocols in place that allow them to do so. But the actual impact of most BTM DER systems is limited to a small portion of the power grid that serves the customer-generator and their neighbors.

Citizens' provided a data response showing that of the 87 solar systems that have been installed on Citizens' grid, 72 were for residential customers.[18] For the typically-sized residential systems, power exported to the Utilities' grid will flow to the nearest load, which in almost all cases will simply be the customer-generator's neighbors. The assets that handle the power flow between these very local sections of the grid – including service drops, line transformers, and feeders – are intrinsically able to handle two-way power flows. Further, the relatively small number of DERs on the Utilities' grids suggest that the systems are too few in number to be highly geographically concentrated.[19]

The situation is somewhat different for the larger PV systems. As discussed above, a customer with a relatively high load and large PV system can have periods when exported power is sizable. However, the Utilities' interconnection process screens for these exact situations prior to allowing a customer to install a generator. If these exports would overload equipment or cause power quality issues for other customers, the prospective customer-generator would have to pay for upgrades to resolve the issues before being able to proceed.

Q28. How do the Utilities' frame exported power?

A28. The Utilities discuss exported power as something that a customer-generator delivers to other customers over the grid. This framing not only fails to acknowledge that the Utilities

[18] Exhibit KL-4, Citizens' response to SP-I-2. There is one "residential" customer that has a 137 kW PV system, which is substantially larger than any other residential system.
[19] Citizens' has about 6,000 residential customers, meaning that roughly 1 in 83 have installed solar.

are the ones that deliver the exported power, but also is used to justify the Billing Demand definition:

> As a result, EDCs like Wellsboro must accommodate the interconnection and net metering of customer generators with capacity of up to 3 MW that use very little electricity supplied by the EDC. In addition, we may have a customer that has generation producing power that exceeds their usage at the service location. **In both scenarios, the customer generator uses the Wellsboro distribution system to deliver its output,** which then offsets the energy that must be delivered to the Wellsboro service territory through the PJM (FE MAIT) transmission system. We are obligated to compensate the customer generator first by netting any electricity used by the account against the exported kWh, then by paying them "full retail value" for the remaining kWh at the end of the year that has not been netted against their usage.[20]

Q29. What happens when power is exported from a customer-generator's premises?

A29. Physically, the power flows from the customer-generator's PV system and serves any on-site loads. Any power beyond that instantaneous on-site need flows through the customer's utility meter, on to the service drop, and on to the Company's grid. From there, the power will flow to the nearest source of load.

Q30. Once the power leaves the customer's meter, who owns it?

A30. The Utilities own ("take title to") the exported power as soon as it flows through the utility meter. And because they now own the energy, it is the Utilities who deliver the power over their own grids to the nearest source of load. When the power finds that load, likely at a neighbor, it flows through that neighbor's utility meter and the neighbor is billed for the energy at their full retail rate.

Q31. Do the Utilities use their entire distribution grid to deliver this exported power?

A31. No, they do not. In most cases, the exported power only flows through a tiny fraction of the Utilities' distribution assets. It may not even flow past the low-side of the line transformer if multiple neighbors share a transformer. Despite this, the Utilities charge the neighbor for the energy at the full retail distribution rate, which is designed to recover the costs of the entire distribution grid.

[20] Farnsworth Direct at 21. (emphasis added)

Q32. Why is this distinction important?

A32. It is important because the Utilities claim that it is appropriate to charge a customer-generator for "the use of" the distribution grid "to deliver its output." This is the basis for using the gross generator rating in the determination of Billing Demand: "Using these measures [net power flow from or onto the Utilities's distribution system] provides an accurate reflection of the Customer's use of the distribution system."[21] But it is not the customer-generator that "uses" the distribution grid "to deliver its output" – it is the Utilities who have already taken title to the exported energy and use their own distribution grid to deliver their own product to another one of their own customers. The customer-generator is compensated for the exported power the instant it leaves the utility meter, and at this point, the customer-generator is no longer the responsible party. Charging them based on this rubric is inappropriate.

D. The Utilities Improperly Expand the Scope of the Commission's UGI Settlement Approval

Q33. What is the Utilities' third justification for their proposal?

A33. Generally, the Utilities argue that the Commission's recent decision in the recent UGI default service docket can be expanded to distribution ratemaking.

> Until recently, we assumed that customer generators must be classified for distribution and generation purposes based on amount of peak electricity that the electric distribution company supplied to the customer generator's account. However, a recent decision by the Commission in Petition of UGI Utilities, Inc-Electric Division for Approval of a Default Service Plan for the Period of June 1, 2025 though May 31, 2029¸ Docket No. P-2004-3049343, et al., indicated that customer generators can be classified for generation purposes according to their peak electricity imported from the EDC or exported to the EDC. We are proposing to clarify in our tariff that we will use customer generator's net power flow from or onto the Company's distribution system to establish the distribution charges

[21] Johnson Direct at 17.

> for the account and eligibility for the Generation Supply Service Rate ("GSSR") 1 or GSSR-2.[22]
>
> I am advised by counsel that the logical legal extension of the UGI decision is that distribution service schedule placement and billing can reflect the customer generator's use of the distribution system, whether through its peak import from the system or its peak export to the distribution system. This ensures non-discriminatory treatment between customers that use the distribution system to power their non-residential operations and those who use the distribution system for the delivery of their energy product.[23]

Q34. Did the Commission explicitly approve the Utilities' proposed Billing Demand definition, or something similar, in the UGI case?

A34. No. The Commission approved a settlement between certain parties that contained, among other elements, a definition that would classify customers into either GSSR-1 or GSSR-2 based on the larger of their power consumption from the grid or their power exports to the grid. The Utilities' proposal does not directly mirror the approved change in the UGI case, and I am advised by counsel that the UGI case has been appealed and is currently before the Pennsylvania Commonwealth Court.

Q35. Given the lack of direct Commission approval, do the Utilities provide any meaningful support for this jump in logic?

A35. No. Citizens' couches its proposal as a shift in assumptions that allows it to "clarify" its tariff, underscoring the magnitude of its proposal. Wellsboro's witness notes a vague "advised by counsel" notion but provides no additional legal support for its change. While I am not an attorney and am not offering legal opinions, I understand that the core issue in the UGI case is currently working its way through Pennsylvania's appeals court process, meaning the matter is far from settled. And against this uncertain backdrop, it is doubly improper to expand the scope of the UGI settlement to distribution rate making. I further note that the UGI change was approved in a default service proceeding, not a distribution rate case as is the case here.

[22] Johnson Direct at 17.
[23] Farnsworth Direct at 22.

Q36. From a policy perspective, is there a difference between setting default service rates and distribution rates?

A36. Yes. Pennsylvania has restructured its electric utility industry, meaning that while the Commission is able to approve the structure of default service plans that utilities provide, it does not directly set prices. By contrast, the Commission does have oversight over the actual rates and rate designs of electric distribution companies ("EDCs"), and is obligated to ensure that utilities implement just and reasonable rates.

A component of ensuring that all Commonwealth residents and businesses pay just and reasonable rates is that EDCs have a burden of proof to justify any proposed changes. In their filings, the Utilities provide scant support for their new definition of Billing Demand, relying instead on a handful of pages of testimony, no legal arguments, and no policy impact analysis. Instead, the proposals' support boils down to vague claims regarding the appropriateness to extend the UGI settlement construct to distribution rates and a specious claim that basing rates on hypothetical energy flows is just and reasonable.

Q37. What is one example of how the Utilities' proposal could result in unjust and unreasonable rates?

A37. The Utilities propose to use base demand charges on the larger of the GGR and the highest 15-minute demand in a given month, even if this value is not reflective of the customer-generator's use of the system: "[t]he Company's proposed Tariff revision for billing demand would include the rated output capacity of the net-metered generator system in the calculation. Rated output capacity may differ from the nameplate capacity of a generating facility and/or the actual peak output."[24] This functionally acts as a 100% demand ratchet based on the installed capacity of the customer-generator's DER system, even if this level of power is never attained by the customer as shown in the Customer C example above.

[24] Exhibit KL-5, Citizens' response to SP-I-13.

The Utilities' current demand ratchet, which sets the billing demand floor at 50% of the demand attained by the customer in the prior 12 months, is at least based on actual power usage by the customer. If a customer uses 100 kW in a given month, then it will be required to pay demand charges based on at least 50 kW of demand for the next 12 months, even if its demand fell to no more than 45 kW on a permanent basis. After the 12-month demand ratchet expires, the billing demand would be reset to the lower value, and a new 50% ratchet floor would be established.

By contrast, a customer-generator could install a 100 kW PV system that never actually produces 100 kW, that never results in 100 kW of exported power, and where the customer never consumes 100 kW of power from the grid, and yet they could be charged a demand charge based on 100 kW for decades as long as their DER was operation. While the Utilities' current demand ratchet sends a poor price signal to reduce demand, it is at least based on actual power flows. The Billing Demand proposal, however, is completely independent from actual power flows and is thus, by definition, arbitrary. And arbitrary definitions should not be considered a sufficient basis for just and reasonable rates.

Q38. Aside from the fact that the Utilities have failed to sufficiently support their proposals, do you have other concerns with the Billing Demand definition and implementation?

A38. Yes. While I am not an attorney and am not making legal arguments, I have 15 years of experience drafting and interpreting legislative language, drafting and interpreting regulatory language, and performing policy analysis that requires a very close reading of relevant statutory authorities. In my review of Pennsylvania's net-metering statute and the Utilities' proposed tariff language and discovery responses, I believe there is an irreconcilable divergence in Utilities' netting proposals and the underlying Pennsylvania statute.

Q39. What is the nature of this divergence?

A39. The Utilities propose to shift compensation for generation from a kWh-based net metering construct to a dollar-based net billing construct. These are two fundamentally different rubrics, and the latter appears to be facially inconsistent with the net metering statue.

Q40. Please describe the traditional kWh-based accounting used in net-metering.

A40. In the traditional approach to net-metering, a single meter was used that was capable of measuring energy delivered to a customer (inflow) and delivered from the customer to the grid (outflow). When the customer's energy use was larger than their DER generation, the inflow energy spun the meter "forward," and each kWh increased the meter's accumulated register. When generation exceeded on-site load, outflow energy spun the meter "backward" and decremented the meter's register.

At the end of the billing period month, the utility would measure the register, compare it to the value at the end of the prior billing period, and determine whether there was net inflow or net outflow for the billing period. If there was net inflow, meaning the customer consumed more power than the produced during the billing period, they would be charged for this net usage at the retail rate. If there was net outflow, meaning the total generation exceeded total consumption, the utility would "carry forward" the kWh credit to be applied against the next month's usage. Depending on state or utility rules, the carry-forward kWh credits may be "cashed out" at the end of a year at a designated price.

Q41. Please contrast this approach with the dollar-based net billing structure.

A41. In a net billing structure, rather than measuring and netting generation and load in kWh, generation and net energy are converted from kWh to dollars based on a specified rate at specific times. The netting may occur on a monthly basis. Under this approach, the meter would "spin" back and forth within the month and excess generation converted to a dollar value at the end of the billing period. Alternatively, the netting may occur on an instantaneous basis. Here, a utility would measure and accumulate all inflow power in one meter register, all outflow power in another meter register. At the end of the billing period, the total inflow power would be multiplied by the full retail rate, and the total outflow

power credited at a potentially different outflow rate. The dollar amounts would be netted against each other and charged to the customer.

Q42. Which of these do the Utilities propose?

A42. The Utilities' proposal is in the middle of these two net billing methods. For customers with Billing Demand larger than 400 kW, they propose an hourly netting with the inflow and outflow rate equal to the PJM real-time locational marginal price ("LMP") at the PJM West Hub.[25]

Q43. Is this change obvious from the Utilities' testimony?

A43. No, and in fact, the Utilities' testimony on this matter is in direct conflict with their actual proposal. Citizens' testimony on this point only refers to the LMP being applicable to the annual cash out: "For customers with Billing Demands over 400 kW, the annual cash out will be a weighted average locational marginal price ("LMP")."[26] Wellsboro similarly says

> We are obligated to compensate the customer generator first by netting any electricity used by the account against the exported kWh, then by paying them "full retail value" for the remaining kWh at the end of the year that has not been netted against their usage. For customers with Billing Demands over 400 kW, the annual cash out will be a weighted average locational marginal price ("LMP").[27]

In both cases, the Utilities' testimony make it appear that they will continue to follow the Pennsylvania net metering statute using a kWh-based net metering approach on a month-to-month basis, and only apply the lower LMP to the final annual cash out calculation. But this testimony is directly contradicted by the Utilities' discovery response, which provides more details about the proposed methodology.[28]

Q44. What is their actual netting proposal for customers with larger Billing Demands?

[25] Exhibit KL-6, Citizens' response to SP-I-4.
[26] Johnson Direct at 17.
[27] Farnsworth Direct at 21.
[28] Exhibit KL-6, Citizens' response to SP-I-4.

A44. When asked to "explain how Citizens intends to 'net' the customer-generators production against its consumption on an annual basis for both GSSR-1 and GSSR-2, broken down by rate class", Citizens' replied:

> For GSSR-1 customers, net energy consumption is calculated in the customer-generators utility meter billing read register. Net energy is equal to the total energy consumed through the meter minus the energy exported through the meter from one billing read to the next. Net kWh consumption is the same for both distribution and generation billing calculations.
>
> For GSSR-2 customers, the Company proposes to use the same calculation as for GSSR-1 for calculation of distribution billing charges. For generation billing, the customer-generator will be billed for each hour of net consumption at the PJM West Hub Real-time Locational Marginal Price ("LMP"). Each hour of net export will be credited to the generation portion of the customer-generator's bill at the corresponding LMP. Excess credit will carry over to offset generation costs in future bill periods [sic] any excess balance will be cashed out to the customer-generator annually following the May bill cycle.[29]

Here, the Utilities bifurcate their netting approach both by customer size and by rate component. Customers with Billing Demands under 400 kW would be classified as GSSR-1 customers, and the Utilities plan to follow the traditional kWh-based accounting and annual cash out process as stipulated in the statutory language. Similarly, it appears that GSSR-2 customers will have their distribution costs calculated using the traditional approach.

But the proposal for compensating GSSR-2 customers for their generation is decidedly different. Instead of netting kWh on a monthly basis with kWh carryforwards for excess monthly generation, the Utilities propose to convert kWh to a dollar value on an hourly basis and accrue dollar charges and credits throughout the year.

The proposals are unambiguous on this matter. Customer-generators will be "billed" each hour for inflow energy "at the [LMP]", and "credited" each hour for outflow energy "at the corresponding LMP". The dollar-based "excess credit" will offset

[29] Exhibit KL-6, Citizens' response to SP-I-4.

"generation costs in the future" – not excess generation measured in kWh, but excess generation "credits" that offset future "costs". The kWh-based accounting of traditional NEM is completely missing for the generation component, replaced by an hourly net billing structure.

Q45. How does this compare to the Regulation language regarding net-metering?

A45. It is quite different. The relevant portions of the Pennsylvania code follow:[30]

> (d) An EDC and DSP shall credit a customer-generator at the full retail kilowatt-hour rate, which shall include generation, transmission and distribution charges, for each kilowatt-hour produced by a Tier I or Tier II resource installed on the customer-generator's side of the electric revenue meter, up to the total amount of electricity used by that customer during the billing period. If a customer-generator supplies more electricity to the electric distribution system than the EDC and DSP deliver to the customer-generator in a given billing period, the excess kilowatt hours shall be carried forward and credited against the customer-generator's kilowatt-hour usage in subsequent billing periods at the full retail rate. Any excess kilowatt hours that are not offset by electricity used by the customer in subsequent billing periods shall continue to accumulate until the end of the year. For customer-generators involved in virtual meter aggregation programs, a credit shall be applied first to the meter through which the generating facility supplies electricity to the distribution system, then through the remaining meters for the customer-generator's account equally at each meter's designated rate.
>
> (e) At the end of each year, the DSP shall compensate the customer-generator for any remaining excess kilowatt hours generated by the customer-generator that were not previously credited against the customer-generator's usage in prior billing periods at the DSP's price to compare rate.

Q46. What elements of the Utilities' tariffs do you believe to be inconsistent with the Regulation's language?

A46. A plain reading of the Regulation confirms that the "full retail kilowatt-hour rate" includes "generation, transmission, and distribution charges." It further posits that if a customer-generator sends more energy to the EDC or default service provider than they receive (*i.e.*,

[30] 52 Pa. Code § 75.13.

if there is net outflow) in "a given billing period", the "excess kilowatt hours shall be carried forward." Further, this carryforward must be "credited… against kilowatt-hour usage in subsequent billing periods at the full retail rate," which is explicitly defined to include generation, transmission, and distribution charges. Finally, any excess kWh carryforward that is not extinguished in a billing period "shall continue to accumulate until the end of the year."

There is no wiggle room for the Utilities to bifurcate their proposed netting methodologies for generation and transmission from those used for distribution. The statute is clear that all crediting must be done at the "full retail rate" which explicitly includes all three components. Neither is there space to switch from a month-by-month kWh-based accounting framework to a dollar-based one; kWh carryforwards are required to be credited against kWh usage until the end of the year. Only at the end of the year is the conversion between kWh and dollars permissible, where it is done at the price to compare.

Q47. Does the statute define "billing period"?

A47. Yes. While the NEM statute includes a reference to the defined term "billing month" and not "billing period", the PA code provides a cross-reference definition elsewhere.

- 52 Pa. Code § 75.12
  - "Billing month—The term has the same meaning as set forth in § 56.2 (relating to definitions)."[31]
- 52 Pa. Code § 56.2
  - "Billing month—A period of not less than 26 days and not more than 35 days except in the following circumstances:"[32]
  - "Billing period—In the case of public utilities supplying gas, electric and steam heating service, the billing period must conform to the definition of "billing month."[33]

[31] 52 Pa. Code § 75.12.
[32] 52 Pa. Code § 56.2. The "circumstances" relate to customers starting and stopping service, correcting a billing problem, a change in meter reading route, or a change in electricity supplier.
[33] 52 Pa. Code § 56.2.

Based on these definitions, one cannot construe the "billing period" referenced in the netting section of the NEM statute to be an hourly time period as the Utilities propose, as to conform with the definition of billing month, the billing period must be at least 26 days. But the Utilities' proposals sidestep this requirement when it proposes to net energy over each hourly period and convert each hour's net inflow or net outflow to a dollar credit based on LMP.

Q48. Setting aside the legal question, what is the immediate impact of this change when combined with other elements of the Utilities' proposals?

A48. The Utilities propose to classify customers for generation supply service based on the ill-conceived Billing Demand concept. This means that a BTM customer who has pre-solar loads well below the 400 kW cutoff for GSSR-2, and whose post-solar exports are also well below the 400 kW cutoff for GSSR-2, could be shifted to a dramatically different supply tariff if they install a 400 kW PV generator, even if this PV system only offsets a fraction of their annual load.

This change would impact not only the value of their exported solar generation, but also all power they consume. Instead of being billed on the quasi-fixed GSSR-1 rate that is updated every six months, they would be subject to the real-time price fluctuations of the PJM wholesale market. Further, as the Utilities propose to charge and credit customers for their inflow and outflow energy at a rate that is neither known in advance nor fixed for any meaningful period of time, customers who are placed on the GSSR-2 tariff because of the size of their PV generation will no longer be able to determine what they will pay for generation supply nor what their exports will be valued at. These are massive changes for a medium-sized business to manage, particularly if they were not expecting to be shifted to a much more complex tariff.

Q49. Please summarize your testimony and recommendations

A49. The Commission should reject the Utilities' proposals to introduce a new definition of Billing Demand and to classify and charge customers based on this definition. The

Utilities' attempt to bring a concept from a different type of regulatory docket – *i.e.*, a default service case - into this proceeding and expand a non-traditional approach to ratemaking is not rigorously supported by its testimony. Further, because it relies on hypothetical power flows and not actual power flows, it is not a sound basis to produce just and reasonable rates. The result is a rate design that can lead to substantial increases in distribution bills for customer-generators after installing solar, despite the new power flows from the solar system occurring during times when the grid has spare capacity.

In addition, the Utilities' proposals to shift from a kWh-based net-metering approach to a dollar-based net billing approach for generation compensation appears to be in conflict with Pennsylvania's net metering regulations, though I am not a lawyer and am not making a legal conclusion. But regardless of this legal question, the Utilities have not met their burden to demonstrate the sizable policy shift of pushing medium-sized businesses onto a much more complex supply tariff is in the interests of all ratepayers and, therefore, I recommend that the Commission wholly reject the Utilities' ill-conceived proposals.

Q50. Does this conclude your testimony?

A50. Yes, it does.

EXHIBIT KL-1

KEVIN M. LUCAS

SOLAR ENERGY INDUSTRIES ASSOCIATION

Mr. Lucas is Vice President of Policy Analysis for the Solar Energy Industries Association (SEIA). SEIA is the national trade association for the U.S. solar industry. SEIA is leading the transformation to a clean energy economy. SEIA works with its 1,200 member companies and other strategic partners to fight for policies that create jobs in every community and shape fair market rules that promote competition and the growth of reliable, low-cost solar power.

Since 2010, Mr. Lucas has worked in the energy and environment industry focusing on renewable energy, energy efficiency, and greenhouse gas reduction. In his role at SEIA, Mr. Lucas develops expert witness testimony for rate cases, integrated resource plans, and other regulatory proceedings. He also supports SEIA's State Affairs, Regulatory Affairs, and Congressional Affairs divisions on policy and market design matters. Prior to joining SEIA, Mr. Lucas worked for the Alliance to Save Energy, a Washington DC-based nonprofit focused on reducing energy use in the built environment. Before the Alliance, he worked for the Maryland Energy Administration, the state energy office, on numerous legislative and regulatory issues and developed and presented testimony before the Maryland General Assembly and the Maryland Public Service Commission.

Prior to entering the energy and environment field, Mr. Lucas was a manager at Accenture, a leading consulting firm. Mr. Lucas implemented enterprise resource planning software for Fortune 500 companies in industries such as consumer electronics, oil and gas, and manufacturing.

AREAS OF EXPERTISE

- Renewable Energy Policy Analysis: extensive experience analyzing renewable energy policy issues and communicating results to both expert and general audiences.
- Energy Efficiency Policy Analysis: detailed understanding of energy efficiency policies, including the development of potential studies and utility efficiency program design and implementation.
- Quantitative Analysis: deep expertise in quantitative analysis across a broad range of topics including analyzing financial and operational data sets, constructing models to explore electricity industry data, and incorporating original analysis into expert witness testimony.
- Energy Markets: studies interaction of renewable energy and energy efficiency policies with wholesale market operation and price impacts.
- Legislative Analysis: reviews legislation related to energy issues to discern potential impacts on markets, utilities, and customers.

EDUCATION

Mr. Lucas holds a Masters of Business Administration from the University of North Carolina, Kenan-Flagler Business School (2009) and a Bachelor of Science in Engineering, Mechanical Engineering from Princeton University (1998).

ACADEMIC HONORS

- Beta Gamma Sigma Honor Society
- Paul Fulton Fellowship, Kenan-Flagler Business School
- Graduated *cum laude* from Princeton University

KEVIN M. LUCAS

SOLAR ENERGY INDUSTRIES ASSOCIATION

EXPERT WITNESS TESTIMONY

Arizona Corporation Commission

- Docket No. E-01345A-19-0236 – *In the Matter of the Application of Arizona Public Service Company for a Hearing to Determine the Fair Value of the Utility Property of the Company for Ratemaking Purposes, to Fix a Just and Reasonable Rate of Return Thereon, to Approve Rate Schedules Designed to Develop Such Return.*
    - Analyzing and modifying APS's class cost of service study, arguing for changes to time of use rate design, proposing new rate designs for solar plus storage installations, proposing improvements to non-residential rate designs, advocating for a "bring your own device" program.
- Docket No. E-01933a-22-0107 – *In the Matter of the Application of Tucson Electric Power Company for the Establishment of Just and Reasonable Rates and Charges Designed to Realize a Reasonable Rate of Return on the Fair Value of the Properties of Tucson Electric Power Company Devoted to its Operations Throughout the State of Arizona and for Related Approvals.*
    - Direct and rebuttal testimony advocating for a "bring your own device" program designed to optimize the use of solar plus storage systems, proposed and designed new storage-supporting residential and non-residential tariffs, argued for the removal of an out-of-date fee for distributed solar metering equipment.
- Docket No E-01345A-22-0144 – *In the Matter of the Application of Arizona Public Service Company for a Hearing to Determine the Fair Value of the Utility Property of the Company for Ratemaking Purposes, to Fix a Just and Reasonable Rate of Return Thereon, and to Approve Rate Schedules Designed to Develop Such Return.*
    - Direct and rebuttal testimony advocating for a "bring-your-own-device" program designed to optimize the use of solar plus storage systems, proposed and designed new storage-supporting residential and non-residential tariffs, argued against APS's cost of service study for solar customers.

Public Utilities Commission of the State of Colorado

- Proceeding 17A-0797E – *Public Service Company - Accelerated Depreciation - AD/RR*
    - Advocating for appropriate structure to utilize renewable energy funds to support the early retirement of coal facilities and to continue to support distributed resources.
- Proceeding 19A-0369E – *In the Matter of The Application of Public Service Company of Colorado For Approval of Its 2020-2021 Renewable Energy Compliance Plan*
    - Advocating for changes to better support solar and solar plus storage installations
- Proceeding 19AL-0687E - *In the Matter of Advice No. 1814-Electric of Public Service Company of Colorado to Revise its Colorado P.U.C. No. 8 – Electric Tariff to Reflect a Modified Schedule RE-TOU and Related Tariff Changes to be Effective on Thirty-Days' Notice*
    - Designed and advocated for new data-based default time of use rate.

Public Utilities Commission of the State of Colorado – Cont.

- Proceeding No. 21A-0141E – *In the Matter of the Application of Public Service Company of Colorado for Approval of its 2021 Electric Resource Plan and Clean Energy Plan.*
    - Argued for changes to proposed resource plan to more accurately reflect capabilities of solar and storage, to updated template contracts, and improve procurement process.
- Proceeding No. 21A-0625EG – *Public Service Company - Renewable Energy Compliance Plan.*
    - Advocated for various program modifications and enhancements for the utility's four-year distributed generation and community solar plan.
- Proceeding No. 23AL-0243E – *In the Matter Of Advice Letter No. 1923-Electric Of Public Service Company Of Colorado To Revise Its Colorado P.U.C. No. 8-Electric Tariff To Reset The General Rate Schedule Adjustments, To Place Into Effect Revised Base Rates, And To Implement Other Phase II Tariff Proposals To Become Effective June 15, 2023*
    - Analyzed novel cost allocation methodology proposed by PSCo, proposed modifications to non-residential rate design, critiqued PSCo's meter cost analysis.
- Proceeding No. 24AL-0377E – *In the Matter Of Advice Letter No. 1960 Filed By Public Service Company Of Colorado To Revise Its Colorado P.U.C. No. 8 – Electric Tariff To Modify Time-Of-Use ("Tou") Tariffs For Electric Service, Including Tou Periods And Associated Tou Rates And Charges, To Become Effective October 4, 2024.*
    - Proposed updated TOU schedule based on PSCo's evolving resource mix and decarbonization goals.
- Proceeding No. 24A-0442E – *In The Matter of the Application of Public Service Company of Colorado For Approval Of Its 2024 Just Transition Solicitation*
    - Discussed impacts of solar generation variability, proposed economic analysis of planning reserve margin, analyzed impact of large load customers

Georgia Public Service Commission

- Docket No. 44160 – *In Re: Georgia Power Company's 2022 Integrated Resource Plan* and Docket No. 44161 – *In Re: Georgia Power Company's Application for the Certification, Decertification, and Amended Demand Side Management Plan*
    - Advocated for improvements to proposed procurement plan with an increased focus on solar plus storage projects and distributed energy resources; recommended expansion of monthly netting program for BTM solar projects.
- Docket No. 44280 – *Georgia Power 2022 Rate Case*
    - Analyzed and critiqued Georgia Power's rate case filing, specifically regarding its proposed flat interconnection fee for DG systems, its purported cost shift associated with BTM solar customers, its consistent and sizable excess revenue collection over a decade, and various proposals to modify or eliminate residential tariffs.

Illinois Commerce Commission

- Docket No. 22-0486 – *Commonwealth Edison Company Order Requiring Commonwealth Edison Company To file an Initial Multi-Year Integrated Grid Plan And Initiating Proceeding to Determine Whether The Plan is Reasonable and Complies with the Public Utilities Act.* and 23-0055 – *Verified Petition for Approval of a Multi-Year Rate Plan under Section 16-108.18 of the Public Utilities Act.*
    - Designed and advocated for a virtual power plan program and community solar and storage program to help assist ComEd with its demand reduction goals. Also recommended approval of meter collar adaptors as a way to reduce solar install costs.
- Docket No. 22-0487 & 23-0082 – Ameren Illinois Company d/b/a Ameren Illinois Petition for Approval of a Multi-Year Rate Plan Pursuant to 220 ILCS 5/16-108.18.
    - Designed and advocated for a virtual power plan program and community solar and storage program to help assist Ameren with its demand reduction goals. Also recommended approval of meter collar adaptors as a way to reduce solar install costs.

Maryland Public Service Commission

- Case 9153, 9154, 9155, 9156, 9157, 9362 – *In the Matter of Maryland Utility Efficiency, Conservation and Demand Response Programs Pursuant to the Empower Maryland Energy Efficiency Act of 2008*
    - Multiple filings regarding the design and implementation of Maryland's energy efficiency portfolio standard.
- Case 9271 – *In re the Merger of Exelon Corp. & Constellation Energy Grp., Inc.*
    - Analysis of renewable energy commitments in merger proposal.
- Case 9311 – *In re the Application of Potomac Elec. Power Co. for an Increase in its Retail Rates for the Distrib. of Elec. Energy*
    - Supporting the implementation of a limited cost tracker to accelerate reliability investments after 2012 Derecho.
- Case 9326 – *In re the Application of Balt. Gas & Elec. Co. for Adjustments to its Elec. & Gas Base Rates.*
    - Supporting the implementation of a limited cost tracker to accelerate reliability investments after 2012 Derecho.
- Case 9361 – *In re the Matter of the Merger of Exelon Corporation and Pepco Holdings, Inc.*
    - Policy analysis of merger proposal.

Michigan Public Service Commission

- Case U-18419 – *In the matter of the application of DTE ELECTRIC COMPANY for approval of Certificates of Necessity pursuant to MCL 460.6s, as amended, in connection with the addition of a natural gas combined cycle generating facility to its generation fleet and for related accounting and ratemaking authorizations.*
    - Arguing against DTE Electric's proposal to construct a new natural gas combined cycle generating facility and instead meet its future capacity and energy needs with a distributed portfolio of solar, wind, energy efficiency, and demand response.
- Case U-20162 – *In the matter of the Application of DTE Electric Company for authority to increase its rates, amend its rate schedules and rules governing the distribution and supply of electric energy, and for miscellaneous accounting authority*
    - Arguing against DTE Electric's proposal for a net energy metering successor tariff that improperly undervalued the contribution of distributed solar.
- Case U-20165 – *In the matter of the application of Consumers Energy Company for approval of its integrated resource plan pursuant to MCL 460.6t and for other relief.*
    - Discussing Consumers Energy Company's integrated resource plan, arguing for advancing the deployment of solar to meet its capacity requirements, arguing against Consumers' proposed financial compensation mechanism for third-party PPA contracts, supporting a robust PURPA market, and supporting transparent and equitable competitive procurement guidelines.
- Case U-20471 – *In the matter of the Application of DTE Electric Company for approval of its integrated resource plan pursuant to MCL 460.6t, and for other relief.*
    - Evaluating DTE's integrated resource plan, arguing for the Company to modify its modeling assumptions for solar, analyzing the operation and reliability of DTE's aging peaker fleet, demonstrating that solar and solar plus storage could replace some of DTE's peakers, advocating for robust competition and third-party access to new resources.
- Case U-20836 – *In the matter of the application of DTE Electric Company for authority to increase its rates, amend its rate schedules and rules governing the distribution and supply of electric energy, and for miscellaneous accounting authority.*
    - Critiquing DTE's Stable Bill tariff as poorly designed and not reflective of costs; arguing against the requirement for solar customers to take service on the Stable Bill tariff; calculating a new cost-based outflow tariff for exported solar energy.
- Case U-21193 - In the matter of the application of DTE Electric Company for approval of its Integrated Resource Plan pursuant to MCL 460.6t, and for other relief.
    - Discussing interconnection reforms that would facilitate incremental renewable energy capacity
- Case U-21224 – *In the matter of the application of Consumers Energy Company for authority to increase its rates for the generation and distribution of electricity and for other relief.*
    - Critiquing Consumes Energy's proposed outflow compensation for DG customers, its minimum bill proposal, and supporting changes in its cost-of-service model.

Public Utility Commission of Nevada

- Docket Nos. 17-06003 & 17-06004 Phase III – Rate Design – *Application of Nevada Power Company d/b/a NV Energy for authority to adjust its annual revenue requirement for general rates charged to all classes of electric customers and for relief properly related thereto.*
    - Arguing against Nevada Power Company's proposal to increase fixed customer charge.
- Docket No. 24-02026 – Rate Design - *Application of Sierra Pacific Power Company d/b/a NV Energy and Sierra Pacific Power Company d/b/a NV Energy for Authority to Adjust its Annual Revenue Requirement for General Rates Charged to All Classes of Electric Customers and For Relief Properly Related Thereto.*
    - Arguing against Sierra Pacific Power Company's proposal to increase fixed customer charge and solar cost of service study

North Carolina Utility Commission

- Docket E-100 Sub 165 – *2020 Integrated Resource Plans*
    - Advocating for modifications to Duke Energy's IRP, including assumptions on capital and O&M costs, operational assumptions, and natural gas forecast methodology.

Public Service Commission of South Carolina

- Docket Nos. 2019-224-E and 2019-225-E – *South Carolina Energy Freedom Act (House Bill 3659) Proceeding Related to S.C. Code Ann. Section 58-37-40 and Integrated Resource Plans for Duke Energy Carolinas, LLC and Duke Energy Progress, LLC*
    - Advocating for modifications to Duke Energy's IRP, including assumptions on capital and O&M costs, operational assumptions, and natural gas forecast methodology.

Public Utility Commission of Texas

- Docket 46831 – *Application of El Paso Electric Company to Change Rates*
    - Critiquing El Paso Electric's proposal to implement a three-part rate for residential and small commercial net metered customers.
- Docket 57568 - *Application of El Paso Electric Company for Authority to Change Rates*
    - Critiquing El Paso Electric's proposal to implement a three-part rate for residential and small commercial net metered customers, proposing an alternative time of use rate

Virginia State Corporation Commission

- Case No. PUR-2021-00146 – *For approval of the RPS Development Plan, approval & certification of proposed CE-2 Solar Projects pursuant to § 56-580 D and 56-46.1 of the Code of Virginia, revision of rate adjustment clause, designated Rider CE, under §56-585.1 A 6 of the Code of Virginia, and a prudence determination to enter into power purchase agreements pursuant to § 56-585.1:4 of the Code of Virginia.*
    - Evaluating Dominion Energy's compliance with the RPS requirements of the Virginia Clean Economy Act
- Case No. PUR-2024-00161 - *Petition of Appalachian Power Company for Approval to Revise its Net Metering Program Pursuant to § 56-594 of the Code of Virginia*
    - Analyzing and critiquing Appalachian Power Company's proposal to modify its net metering construct

EXHIBIT KL-3

SP-I-21

Explain the ongoing distribution rate Citizens would receive for a net-metered 450 kWAC system in their territory as compared to that same system connected as a PJM wholesale generator.

Response Provided By:
Nathan Johnson, President & CEO, Citizens' Electric Company

Date: June 26, 2025

Response:

The company cannot provide exact rate implications of a net-metered 450kW$_{AC}$ generation system. A number of parameters including, but not limited to:

- Existing load at service
  - Existing kWh usage behind the meter
  - Magnitude and timing of existing demand peak(s)
  - Load factor of existing load

- Nature of generating system
  - Parasitic load magnitude and characteristics
  - Coincidence of generation with existing load demand peak(s)
  - Type and nature of generation source

- Generation interconnection characteristics
  - Phase
  - Voltage

While no single answer is possible or appropriate for this question, the Company has provided an attachment, titled SP-I-21 Attachment A providing several hypothetical net-metered installations. The scenarios examined in the attachment are described below:

Scenario A:	450kW$_{AC}$ Rack Mounted SPV Array (Parameters provided in spreadsheet) with no co-located load.
Scenario B:	Scenario A SPV system with co-located ~420kW$_{AC}$ 3ph GLP-3 load.
Scenario C:	Scenario A SPV system with co-located 562MWh annual usage 3ph GLP-3 load.

The Company is unable to provide a distribution rate comparison case for the same system connected as a PJM wholesale generator. Distribution rates for a standalone wholesale generator would be negotiated in a site-specific contract, for which the Company has no comparable examples.

EXHIBIT KL-4

SP-I-2

How many customer generators have applied for interconnection, or are already interconnected, in the Citizens' service territory, and what is the kw rating and estimated kWh production of each? Please break down by rate class.

Response Provided By:
Nathan Johnson, President & CEO, Citizens' Electric Company

Date: June 26, 2025

Response:

There are currently 99 known existing or applied-for interconnections on the Company's system. See the attachment titled SP-I-2 Attachment A for the requested detailed listing. Estimated kWh production is provided as listed on the interconnection application unless no production was provided, or the provided number was invalid.

EXHIBIT KL-5

SP-I-13

Does Citizens intend to base demand charges for GSSR-2 customer generators on the nameplate capacity of the generating facility or the actual peak output, if they differ?

Response Provided By:
Nathan Johnson, President & CEO, Citizens' Electric Company

Date: June 26, 2025

Response:

The Company's proposed Tariff revision for billing demand would include the rated output capacity of the net-metered generator system in the calculation. Rated output capacity may differ from the nameplate capacity of a generating facility and/or the actual peak output.

EXHIBIT KL-6

SP-I-4

Explain how Citizens intends to "net" the customer-generators production against its consumption on an annual basis for both GSSR-1 and GSSR-2, broken down by rate class.

Response Provided By:
Nathan Johnson, President & CEO, Citizens' Electric Company

Date: June 26, 2025

Response:

For GSSR-1 customers, net energy consumption is calculated in the customer-generators utility meter billing read register. Net energy is equal to the total energy consumed through the meter minus the energy exported through the meter from one billing read to the next. Net kWh consumption is the same for both distribution and generation billing calculations.

For GSSR-2 customers, the Company proposes to use the same calculation as for GSSR-1 for calculation of distribution billing charges. For generation billing, the customer-generator will be billed for each hour of net consumption at the PJM West Hub Real-time Locational Marginal Price ("LMP"). Each hour of net export will be credited to the generation portion of the customer-generator's bill at the corresponding LMP. Excess credit will carry over to offset generation costs in future bill periods any excess balance will be cashed out to the customer-generator annually following the May bill cycle.

REVISED

Statement No. 2-SR, Surrebuttal Testimony of Kevin Lucas

(Tracked Changes)

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	
	:	Docket No. R-2025-3054394
Citizens' Electric Company of Lewisburg, PA	:	
	:	

SURREBUTTAL TESTIMONY OF KEVIN LUCAS ON BEHALF OF KELLY ROAD SOLAR, LLC, LANCASTER AVENUE SOLAR, LLC, AND TWILIGHT RENEWABLES, LLC

REVISED – Tracked Changes Version

Solar Projects' Statement No. 1-SR
August 28, 2025

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I. INTRODUCTION AND QUALIFICATIONS

Q1. PLEASE STATE FOR THE RECORD YOUR NAME, POSITION, AND BUSINESS ADDRESS.

A1. My name is Kevin Lucas. I am the Vice President of Policy Analysis at the Solar Energy Industries Association ("SEIA"). My business address is 1425 K St. NW #1000, Washington, DC 20005.

Q2. ARE YOU THE SAME KEVIN LUCAS THAT SUBMITTED DIRECT TESTIMONY IN THIS CASE?

A2. Yes, I am.

Q3. WHAT IS THE PURPOSE OF YOUR SURREBUTTAL TESTIMONY?

A3. The purpose of my rebuttal testimony is to address several arguments raised by Citizens' Electric Company of Lewisburg, PA ("Citizens'" or "the Company") and by the Pennsylvania Office of Consumer Advocate ("OCA").

Q4. DOES YOUR FAILURE TO ADDRESS A PARTICULAR WITNESS OR ISSUE IMPLY SUPPORT OF THAT WITNESS OR ISSUE?

A4. No, it does not.

Q5. PLEASE SUMMARIZE YOUR FINDINGS AND RECOMMENDATIONS

A5. The arguments advanced in Company's rebuttal testimony do little to bolster support for its Billing Demand proposal. It continues to claim that customer-generators should be billed based on demand they do not place on the system, and its rebuttal offer to "phase in" the results of its punitive proposal do not remedy the inherent flaws in the concept.

Citizens' admits that customer-generator's exported power may not cause incremental costs on its system, but it proposes to substantially increase distribution costs for these customers because of nebulous "new obligations" that they place on the system. However, these "obligations" are completely undefined, unsupported with analysis, and do not correspond to the physical use of the system by customer-generators. Despite this, the Company has doubled down on its flawed proposal, recalculating its rates based on the higher (and seemingly incorrect) inclusion of the new Billing Demand definition.

The results are even higher bills for customer-generators, despite no change in their usage of the system. I continue to recommend the Commission fully reject the proposed Billing Demand proposal.

In response to the Office of Consumer's Advocate ("OCA") discovery requests following the direct testimony filing, the Company expanded on its reasons why large customer-generators should be shifted off of the GSSR-1 tariff. The additional responses, along with a revised version of a prior analysis, provided the opportunity to scrutinize this proposal further. As with the Company's analysis on the impact of the Billing Demand proposal that I discussed in my direct testimony, I found the Company's analysis and reasoning wanting.

The Company has improperly discounted the non-trivial contribution that solar customer-generators make to reducing capacity costs on the Default Service Provider ("DSP") contract, in part due to a flawed analysis. After fixing the Company's errors, I find that not only do solar customer-generators reduce capacity costs, they reduce them in a manner that provides more value than the average cost to serve the DSP load. Put another way, the avoided cost value of solar generation on the DSP contract is higher than the Price to Compare ("PTC") cost of the DSP contract.

This finding renders moot the Company's claim that compensating annual excess energy from customer-generators at the PTC results in a cost shift to non-customer-generator customers. Instead, all customers taking service on the DSP contract benefit from the addition of solar generation on the Company's distribution grid. Additionally, a review of the Company's most recently approved DSP contract does not reveal any price increase due to a higher risk premium than the prior contract, despite concerns raised by OCA. Given this, I recommend the Commission allow customer-generators to take service on whatever DSP rate they prefer.

II. REBUTTAL OF CITIZENS' WITNESSES GORMAN AND JOHNSON

Q6. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A6. In this section of testimony, I discuss the rebuttal testimony of Company witnesses Howard S. Gorman[1] and Nathan Johnson.[2]

Q7. PLEASE SUMMARIZE YOUR FINDINGS.

A7. The Company introduces several new arguments in its rebuttal testimony. It argued that there is precedent under its demand ratchet and minimum billing provisions for billing customers not based on their actual usage, but some other measure. But these measures are fundamentally different in nature than the proposed Billing Demand metric, and raise their own concerns.

Citizens' claims that its proposal will reduce customer confusion. However, it is not distinguishing between the very few customers that would be required to switch to the GSSR-2 rate from the many more customer-generators that would see sizable distribution bill increases due to the same definitional change. Far form reducing customer confusion, the proposal will likely incite frustration among most customer-generators.

The Company introduces a new and inflammatory claim that the GSSR-1 tariff provides the perverse incentive for customer-generators to intentionally act to harm the rest of the ratebase by turning off their systems during peak hours in an effort to manipulate the capacity market to their benefit. This is an extraordinary argument, which not only lacks extraordinary support, but lacks any evidence or analysis whatsoever. The Company's argument is farcical in its face given a small customer-generator has no ability to effectively manipulate the price of the multi-billion dollar, multi-Gigawatt PJM capacity market. The Company's unfortunate testimony on this point can only be seen as an effort to unjustly discredit customer-generators and should be fully disregarded by the Commission.

[1] Citizens Statement No. 1R - Rebuttal Testimony and Exhibit of H. Gorman ("Gorman Rebuttal").
[2] Citizens' Statement No. 4R - Rebuttal Testimony and Exhibits of Nathan Johnson ("Johnson Rebuttal").

In its rebuttal testimony, the Company recalculated its rates based on the proposed Billing Demand definition. The new rates exacerbate the issues identified in my direct testimony, causing an even more punitive rate impact for customer-generators based on demand they do not place on the system and costs they do not impose. The result is an even more stark bill increase that appears to only benefit non-customer-generators.

Finally, I revisit the Company's updated analysis on the capacity contribution of solar generation and its ability to reduce costs on the DSP contract. I find that, contrary to the Company's claims, the avoided cost benefits of the solar generation profile handily exceed the cost of serving the DSP load profile. Quite simply, paying customer-generators for their excess power at the PTC undercompensates these customers for the excess generation. Given this was the main reason why the Company proposes to require larger customer-generators to take service on the GSSR-2 rate, I recommend the Commission reject this proposal and allow customer-generators to take service on whichever rate they prefer.

A. Ratemaking and Demand Ratchet

Q8. MR. GORMAN ARGUES THAT YOUR OBSERVATION THAT THE IMPACT TO THE COMPANY'S SYSTEM IS LIMITED TO THE SMALL SET OF ASSETS THAT SERVE A CUSTOMER-GENERATOR IS NOT RELEVANT FOR RATEMAKING PURPOSES.[3] HOW DO YOU RESPOND?

A8. Mr. Gorman does not disagree with the fact that any impact to the Company's system from customer-generator systems is limited to the assets serving that customer. This is readily observable when the Company experiences a limited outage on its distribution system from downed trees or equipment failures. Customers on distant parts of the Company's grid are not impacted and continue to receive service as they are not directly served by the assets experiencing the outage. Similarly, the physical impact on the

[3] Gorman Rebuttal at 18.

Company's system from a customer-generator is necessarily limited to the assets that serve that customer, and those impacts are attenuated as one moves further upstream from local line transformers to feeders to substations as the usage is blended in with dozens, hundreds, or thousands of other loads.

Instead, Mr. Gorman argues that rates are designed to "recover its costs for the entire distribution system, from all its customers", with an exception for customer-dedicated assets. This statement is accurate, but it not only missed the point of my testimony, it runs counter to the entire basis of the Company's Billing Demand proposal: that customer-generators are imposing differential obligations through their use of the system and must be treated differently than in the past and from other customers.

Q9. WHERE IN THE RATEMAKING PROCESS DOES THIS DECISION GET MADE?

A9. The decision to implement the Billing Demand proposal is "upstream" from cost allocation and rate design components of the ratemaking process. Put another way, the Billing Demand decision is a precursor to the Company's cost of service study and rate design steps. In fact, in the Company's rebuttal testimony, it recalculated its demand rates based on the new definition of Billing Demand and allowed for potential future revisions to cost allocation "which can be eventually based on the actual class data."[4] So while it is true that the mechanical steps of ratemaking is intended to recover costs of the entire system from customers, the specific results are very much a result of which assumptions and methodologies a utility proposes.

Q10. DO YOU CONTINUE TO BELIEVE THAT THE COMPANY MODIFIED ITS RATEMAKING PROCESS BASED ON A FAULTY PREMISE?

A10. Yes. The Company attempts to justify disparate treatment of these customers by billing them not based on their actual usage but their potential usage of the system because it claims they impose burdens on the system that are not captured through the traditional

[4] Gorman Rebuttal at 4.

measures of imported demand. It bases these arguments not on how it must plan and operate its entire system writ large, but instead on how it must serve these individual customer-generators: "From a distribution perspective, we have to plan the same for a customer that is exporting 400 kW to Citizens' as we do for a customer that is receiving 400 kW from Citizens'. In fact, our planning for the export of power to us is more complicated because of potential variability, voltage sags/surges and other issues."[5]

In other words, the Company's justification for the Billing Demand proposal is specific to the usage characteristics of customer-generators, and it is on the robustness of this argument that the proposal must be measured. The Company cannot sidestep this crucial step by claiming that the end result is based on all the costs on the entire grid; it must instead justify its Billing Demand proposal on the facts of said usage. And as I discussed in my direct testimony, I do not believe the Company has met this burden.

Q11. MR. JOHNSON AND MR. GORMAN POINT TO THE USE OF BILLING DEMAND RATCHETS AS A PRECEDENT FOR NOT CHARGING CUSTOMERS BASED ON THEIR ACTUAL USAGE.[6] HOW DO YOU RESPOND?

A11. Mr. Johnson observed that "from July 2024 to May 2025, only 52% of non-residential bills charged for the actual metered demand during the same period" due to the 50% demand ratchet. Mr. Gorman had a slightly different figure, saying that only 49% of customers were billed based on their actual demand.[7] Regardless of whether it is 52% or 49% of customer bills that are caught by the demand ratchet, this is a troubling result. Given that nearly all of the distribution assets that serve customers are shared assets that are planned, sized, and operated to meet the diversified demand of the customers on the assets, it appears the Company is charging customers based on what are likely anomalous

[5] Citizens' Statement No. 4 at 17.
[6] Johnson Rebuttal at 39.
[7] Gorman Rebuttal at 15. Mr. Gorman states "Approximately 51% of all customer bills issued for GLP-1 and GLP-3 during the year are billed using the alternative measure (i.e., 50% of the highest monthly Billing Demand during the prior 11 months) rather than the metered monthly demand usage."

non-coincident peak ("NCP") demand that may have nothing to do with the cost causation of those demands.

The Company's statement means that roughly half of customer bills were for monthly peak demands that were less than half of the single maximum peak demand in the prior year or less than the 5 kW minimum demand on the GLP-1 tariff. For example, this could mean that a customer who had a peak demand of 100 kW in one month had demands of less than 50 kW in all other months would still be charged for 50 kW of usage for up to 11 months even if the 100 kW was an unusual outlier. Unless the Company has definitive evidence that even half of this peak demand of 100 kW was reflective of the cost-causing demand that they actually placed on the system, then it may be charging customers inappropriately based on a demand ratchet that is not tied to costs. I recommend the Commission investigate this issue further and request that the Company demonstrate that its use of the demand ratchet results in appropriate bills for its customers.

Q12. IS THIS DEMAND RATCHET ISSUE EXACERBATED WHEN COMBINED WITH THE PROPOSED BILLING DEMAND DEFINITION?

A12. Yes. There is a key distinction between being billed based on a demand ratchet and being billed based on the Company's proposed Billing Demand methodology. As problematic as the demand ratchet may be, it at least is based on some fraction of actual demand that a customer has placed on the grid in the prior 11 months. By contrast, the Billing Demand methodology is based on a hypothetical demand value that *may never be placed* on the Company's grid and can be substantially larger than any actual measure of demand the customer-generator draws from or places onto the Company's system.

Q13. DO YOU HAVE A ROUGH SENSE OF HOW SIZABLE THIS DIFFERENCE COULD BE?

A13. Yes. In my direct testimony, I corrected the Company's analysis related to how its Billing Demand proposal would impact a hypothetical customer.[8] As part of the modifications of the workpaper, I enabled functionality to quickly modify the customer peak demand and solar system and calculate the resulting power flows and customer Billing Demands under the current and proposed definition. I simulated potential combinations of customer peak demand and PV system size, with the results shown below in Table 1.

Billing Demand / Inflow Ratio				
	Customer Peak Demand			
PV System Size	**25**	**50**	**75**	**100**
25	1.27	1.00	1.00	1.00
50	2.55	1.27	1.00	1.00
75	3.83	1.91	1.27	1.00
100	5.11	2.55	1.69	1.27
125	6.40	3.19	2.12	1.59
150	7.68	3.83	2.55	1.91
175	8.96	4.47	2.98	2.23
200	10.25	5.11	3.41	2.55
225	11.53	5.75	3.83	2.87
250	12.82	6.40	4.26	3.19

Table 1 – Biling Demand / Inflow Demand Ratio

Q14. HOW DO YOU INTERPRET THESE RESULTS?

A14. The values in the table show the ratio of the average monthly customer peak demand under proposed Billing Demand definition and the current peak demand definition. The columns represent customers with different size peak demands (ranging from 25 kW to 100 kW in 25 kW increments), while the rows represent different size PV systems (ranging from 25 kW to 250 kW in 25 kW increments). The intersection of the row and column contains the result of dividing the average Billing Demand value by the average peak demand value. For instance, a customer with a 50 kW peak demand and a 100 kW PV system would see an average monthly Billing Demand that was 2.55 times larger than

[8] Lucas Direct at 9.

the current peak demand measurement, even if they never exported 100 kW to the Company's grid.

Q15. WHAT PERCENTAGE OF THAT CUSTOMER'S ANNUAL USAGE WOULD BE MET BY THAT SIZE SOLAR SYSTEM?

A15. Using the Company's example customer scaled to 50 kW peak demand, a 100 kW solar system would only cover about 51% of their annual load. Despite this relatively modest system size, the Company's proposed Billing Demand definition would result in distribution demand charges that are more than 2.5 times higher than under the current definition. For a customer wishing to offset their entire annual load, the new Billing Demand would be about 5 times higher than the current definition. This stands in stark contrast to the Company's demand ratchets, which are only triggered when peak demand falls below 50% of what a customer has already attained in the prior 11 months.

Q16. IS THERE ANOTHER PROBLEMATIC INTERACTION BETWEEN THE BILLING DEMAND DEFINITION AND THE DEMAND RATCHET?

A16. Yes. Because the demand ratchet would set the minimum demand based on the new Billing Demand definition – which could be based entirely on the gross generator rating ("GGR") of the PV system – a customer who meets more than roughly 20% of their annual usage could never reduce their ratcheted demand without changing the PV system hardware.[9] Using the Company's example customer's load profile, if a customer with a 100 kW peak demand installed an 80 kW PV system, they would offset roughly 20% of their annual usage and see their peak inflow demand fall from 100 kW to 80 kW. But because their Billing Demand could never fall below 80 kW due to the GGR, even if they took actions to further reduce their demand below 80 kW, they would get no relief on their demand charges because the GGR would set the billing demand floor in every month.

[9] Using the Company's example load profile, a customer with a PV system equal to 80% of their peak demand (e.g., a 100 kW customer with an 80 kW PV system) would see their demand switch from their actual usage of the grid to the GGR.

B. Customer Confusion, Alternative Definition of Billing Demand, and Billing Demand Phase In

Q17. THE COMPANY CONTINUES TO ASSERT THAT ITS BILLING DEMAND DEFINITION WILL "REDUCE CUSTOMER CONFUSION."[10] WHAT IS YOUR RESPONSE TO THAT?

A17. I disagree, and in fact, it is difficult to see how customer confusion would not increase under the proposal. The Company proposes to use the Billing Demand definition for two purposes: 1) assigning a customer taking default service to either GSSR-1 or GSSR-2, and 2) billing customers for a portion of their distribution costs. The former decision point would only affect customers with DG system sizes over 400 kW_{AC}, which is a small subset of customer-generators. Of the 87 customer-generators (15 of which are non-residential systems) that are currently taking service with the Company, only one is larger than 400 kW_{AC}.[11] Of the additional 12 projects that are listed as "Indicated" or "Applied / In Progress" (5 of which are non-residential), only two exceed 400 kW_{AC}.[12] In other words, even if all of the projects that exist or that the Company is aware of were all built, only three out of 99 would be impacted by the Company's proposal to assign default supply rates based on the 400 kW_{AC} Billing Demand threshold. This change would result in a sizable, negative impact for these individual customers, but it would not result in widespread customer confusion across the entire non-residential customer base.

On the other hand, all of the non-residential customer-generators would be impacted by a sizable change in their bills due to the use of the proposed Billing Demand definition on their distribution bills. Because all but one of these existing customers have system sizes below 400 kW_{AC}, they would not be impacted by the assignment of supply rates, but would nonetheless see sizable distribution bill increases. Why the Company believes that this would result in "reduced customer confusion" and not confused and frustrated customers who just received a huge bill increase is unclear.

[10] Johnson Rebuttal at 25.
[11] Exh. KL-7, SP-I-2 Attachment A.
[12] *Id.*

Q18. IS THE COMPANY OPEN TO USING AN ALTERNATIVE DEFINITION OF BILLING DEMAND?

A18. It appears so, but only if ordered by the Commission.[13] The Company acknowledges that "[t]here are other possibilities that could be used, such as the 15 minutes of maximum bi-directional demand during the billing cycle."[14] But it notes that its current meters are not configured for measuring bi-directional demand and would require reprogramming. It also raises a concern that "using the bi-directional demand could result in an account moving between the GSSR-1 and GSSR-2 net-metering credit process on an annual basis."[15]

Q19. DO YOU SEE EITHER OF THESE AS MAJOR ISSUES?

A19. No, although I continue to believe using bi-directional demand for the purposes of billing customers for their usage to be inappropriate for all the reasons discussed in my direct testimony. That said, if the Commission were to approve that definition, I do not believe these two issues are major impediments to using that definition.

First, the number of meters that would need to be reprogrammed is small as the Company currently only has 15 non-residential customer-generators on its system. Any new customer-generator could have a meter preconfigured for bi-directional measurement before installation, obviating any additional work. Second, while the Company did not provide the peak inflow demand of its customer-generators, it is reasonable to assume that the PV system size will be similar or larger in size than the customer's peak demand.[16] Given only one existing non-residential customer-generator exceeds the 400 kW_{AC} threshold (and, at 1.77 MW, by a sizable amount), the only way for other customer-generators to switch between GSSR-1 and GSSR-2 on an annual basis due to their actual peak bi-directional demand would be for their imported power to fluctuate above and below 400 kW.

[13] Johnson Rebuttal at 25.
[14] *Id.*
[15] Johnson Rebuttal at 26.
[16] As discussed above, a customer seeking to offset a reasonable portion of their annual usage will need to install a PV system that exceeds its peak demand.

Q20. DO YOU BELIEVE THIS WOULD HAPPEN OFTEN?

A20. No. Of the 15 non-residential customer-generators in service, 11 have PV systems under 200 kW_{AC}. For these systems to flip the net imported power from above 400 kW to below 400 kW would require a customer to have a sizable daytime load (e.g., 500 kW), which means the systems are offsetting very little of the customer's annual generation. For the 3 systems between 200 kW_{AC} and 400 kW_{AC}, the daytime load of the customer would need to be even larger.

Given the average GLP-1 customer has a billing demand of 12 kW[17] and that nearly all of the existing non-residential customer-generators take service on this tariff, the odds that all of the customer-generators on this tariff are extreme outliers with several hundred kW of demand is low. More likely, these customers have peak demands that are equal to or lower than their PV system sizes (which are already below the 400 kW_{AC} threshold), meaning that they are highly unlikely to switch between the GSSR-1 and GSSR-2 tariff on an annual basis based on actual power flows.

Q21. THE COMPANY PROPOSES TO PHASE IN THE BILLING DEMAND DEFINITION OVER THREE YEARS FOR DISTRIBUTION RATES.[18] WHAT IS YOUR RESPONSE TO THIS?

A21. This is a solution in search of a problem. First, the Company does not propose to phase in the definition to the supply rate, which would be implemented immediately in January 2026. Second, phasing in the Billing Demand definition over three years does not remedy its flaws; it merely tries to cushion the rate shock that would result from the unsupported proposal. The customers that would be the most impacted by this change – those with large systems relative to their on-site load – the economic life of a solar system is measured in decades, not in years. Phasing in a substantial increase in distribution costs over three years will do little to mitigate the lifetime financial impact on the system.

[17] Schedule B6-3 shows Schedule GLP-1 with 13,644 annual bills and 163,587 kW of annual demand. Dividing the latter by the former results in roughly 12 kW of monthly demand.
[18] Johnson Rebuttal at 22.

C. GSSR-1 and GSSR-2 Price Signals and Incentives

Q22. THE COMPANY SUGGESTS THAT CUSTOMER-GENERATORS TAKING SERVICE ON THE GSSR-2 TARIFF HAVE A GREATER INCENTIVE TO MAXIMIZE EXPORTS DURING PEAK HOURS.[19] WHAT IS YOUR RESPONSE TO THIS?

A22. I disagree with the Company's hypothesis. Mr. Johnson argues that a customer-generator placed on the GSSR-2 tariff will have an incentive to export to the grid "during higher-priced hours."[20] He continues:

> Although a solar generator may be relatively inelastic in producing power in response to hourly prices, many qualifying net-metered generation sources are able to respond directly to price signals. In addition, even the customer-generator with a solar array may be able to reduce the host load consumption to increase its exports during these hours.[21]

Q23. WHAT IS WRONG WITH THIS STATEMENT?

A23. As a primary matter, there is no way for a customer-generator to respond to the price signal provided by the GSSR-2 tariff. That tariff charges (or compensates) generation at the "actual real-time PJM West Hub Locational Marginal Price ('LMP') for each hour of the billing month"[22] The real-time LMP price is recalculated every five minutes throughout the day, and the "actual" value for any given hour cannot be calculated until the hour has already passed since it is necessarily the load-weighted average of the 12 five-minute periods of that hour. In other words, by the time a generator could even know what the real-time hourly rate at which they will be charged (or compensated), their usage (or generation) will have already occurred.

Q24. COULD A CUSTOMER-GENERATOR MONITOR THE REAL-TIME 5-MINUTE LMP INTERVALS AND MODIFY THEIR BEHAVIOR IN RESPONSE TO THESE PRICE SIGNALS?

[19] Johnson Rebuttal at 27.
[20] Johnson Rebuttal at 28.
[21] *Id.*
[22] GSSR-2 Rider

A24. No. PJM itself does not display the price of a 5-minute interval until most of the way through the interval.[23] Further, the idea that a business should be expected to moderate its load in response to price signals that could change by hundreds of dollars per MWh in minutes overstates the likely flexibility of the loads. It is one thing to reschedule a production line 24 hours in advance or even to make planned load adjustments several hours in advance based on expected prices, but actively managing a business enterprise based on minute-by-minute price fluctuations in the PJM wholesale market is a bar too high for nearly all businesses.

More problematically, the PJM real-time LMP frequently experiences unpredictable "needle peaks" where the price may jump by considerable amounts in one 5-minute interval only to fall just as rapidly as the generators on the grid are re-dispatched. For example, on August 25th, real-time prices were low in early morning hours and largely consistent with the day-ahead prices. At 8:10 AM, the Western Hub Real-Time LMP was $22.82/MWh. At 8:15 AM, it increased to $79.90/MWh. At 8:20 AM, it fell back to $25.65/MWh and stayed at or near that level for most of the rest of the morning. These needle peaks are not uncommon, as shown in Figure 1 below.[24] Moreover, they are not predictable since they are necessarily the result of very short-term imbalances in supply and demand resulting from issues such as unplanned generator or transmission line outages or sudden, unanticipated spikes in demand. The suggestion that customer-generators should or would monitor and respond to these "price signals" on a continuous basis is not reasonable.

[23] https://dataviewer.pjm.com/dataviewer/pages/public/lmp.jsf. The prices on the publicly accessible pages updated roughly four minutes into a given five-minute period. For example, the price for the period from 2:40 PM to 2:45 PM was updated on the PJM website at 2:44.

[24] Data accessed from https://dataviewer.pjm.com/dataviewer/pages/public/lmp.jsf at 3 PM on August 25, 2025.

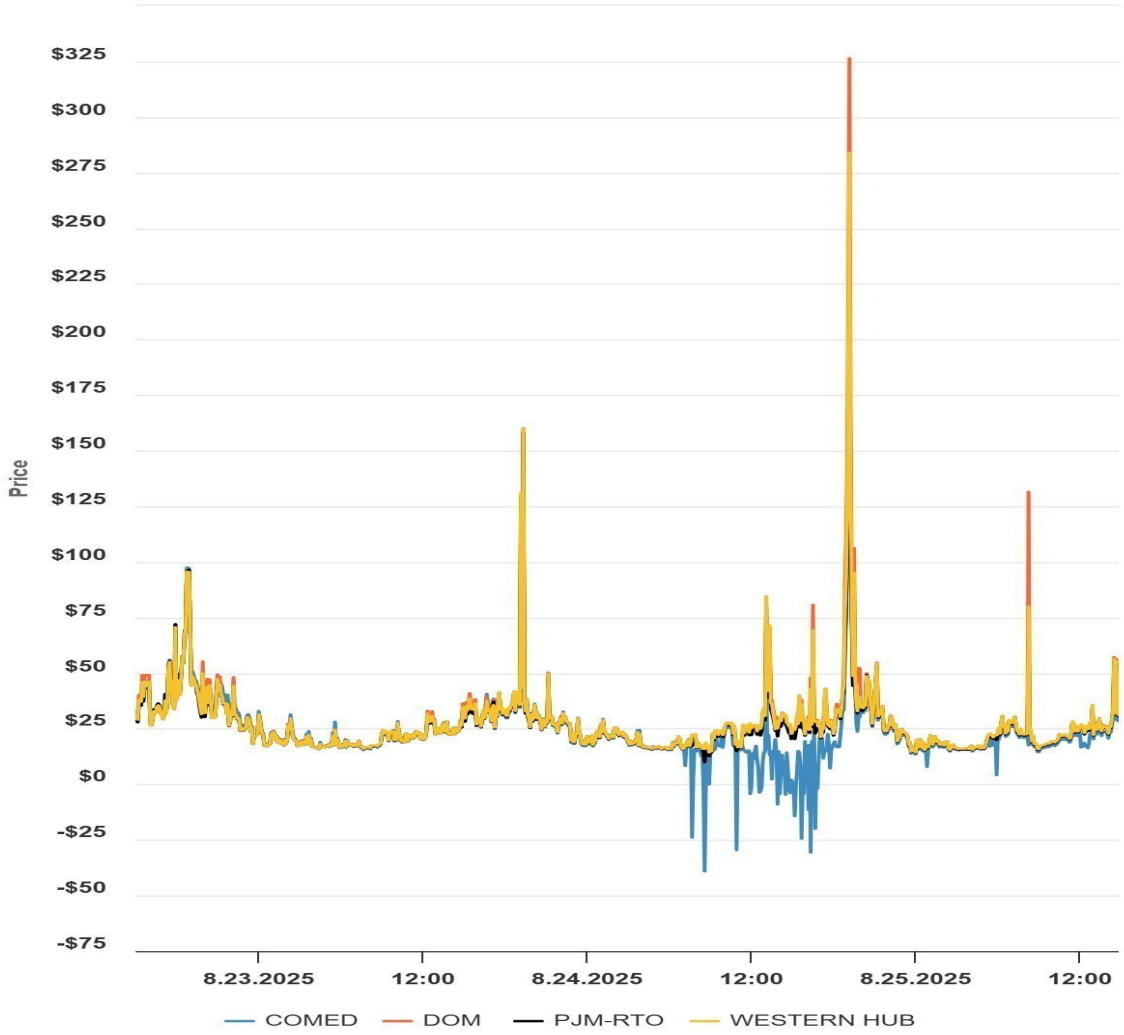

Figure 1 - PJM Real Time Prices August 22, 2025 to August 25, 2025

Q25. DOES THE COMPANY BELIEVE THESE PRICE SIGNALS AND INCENTIVES ALSO EXIST ON THE GSSR-1 RATE?

A25. No. In fact, the Company goes further and suggests that customer-generators have an incentive to withhold generation during peak hours to intentionally increase GSSR-1 rates.

> In fact, the GSSR-1 rate provides an economic disincentive for exporting during high-demand hours. Net exporting customer-generators are paid at the end of the energy-year at the PTC, which includes transmission and capacity costs determined by the Company's contribution to annual PJM peak hours. Exporting during peak hours reduces the Company's costs, thus reducing the value of export credits. Net-metered generation is non-dispatchable and, as Mr. Nolt states in his

> testimony, is able to "go offline immediately" so a customer-generator could reduce or eliminate output during peak hours to maximize the value of future export credits. In short, rather than incentivizing customer-generators to export during peak hours for benefit of all ratepayers in the class, the GSSR-1 rate structure, coupled with net metering code requirements, provide a financial incentive for customer-generators to deny exports during peak hours at the cost of non-exporting ratepayers.[25]

Q26. WHAT IS YOUR PERSPECTIVE ON THIS STATEMENT?

A26. This is a rather staggering accusation. The Company asserts – with no evidence or analysis whatsoever – that customer-generators would engage in market manipulation by intentionally reducing the output of their solar facilities in order to increase the peak demand of customers being served on the GSSR-1 tariff in hopes of inflating the future costs of that rider. It further presupposes that this increased peak demand will necessarily translate into increased costs that must be recovered from GSSR-1 customers, eventually increasing the credit rate at which exported energy is compensated.

Putting aside the unfounded and incredibly cynical basis for the statement, there are three problems with the Company's assertion. First, no customer knows when the five coincident peak hours that will be used in PJM's calculation of generation and transmission capacity cost allocation will occur. These are only announced months after the fact and are by definition retrospective. For a customer-generator to be confident of impacting one of these five hours, they would have to reduce their generation output on many hot afternoons as one simply cannot be determined with any precision when a combination of weather and customer load will trigger one of these system-wide peak hours.

Second, this repeated reduction in generation will have a much larger impact on a generator's compensation than any hypothetical price increase triggered by the intentional withholding of exported power could have. A customer-generator would be taking a sizable risk that forgoing guaranteed revenue by not generating on a given day

[25] Johnson Rebuttal at 28-29.

will result in future price increases that more than offset the lost revenue, particularly given the insignificance of a single distribution-connected DG system on the multi-Gigawatt, multi-billion dollar PJM capacity market.

Third, the DSP contract that the Company has with its wholesale supplier passes through PJM generation capacity and transmission costs directly based on the actual costs apportioned to the Company. The Company then divides these dollars by the kWh sold on the GSSR-1 tariff to determine the GSSR-1 $/kWh rate component for the recovery of generation and transmission costs. If a customer-generator reduced their output, it would result in increased net sales at the Company's PJM settlement point, which means the capacity costs would be divided by a larger quantity of sales. This would tend to reduce, not increase, the $/kWh rate that a customer-generator would be credited for excess generation.

Q27. PUTTING ASIDE THESE ISSUES, IS THERE EVEN A HYPOTHETICAL POSSIBILITY THAT A CUSTOMER-GENERATOR WOULD BENEFIT FROM THE MARKET MANIPULATION SUGGESTED BY THE COMPANY?

A27. No. Suppose a customer on the GSSR-1 tariff had a 100 kW_{AC} PV system that produced 147 MWh per year.[26] For a BTM customer-generator, much of this production will be used on-site and will not result in exported power. But to illustrate a worst-case scenario, suppose that all power was exported and compensated at the GSSR-1 rate.

The GSSR-1 rate used in the Company's workpapers included was $110.77/MWh, $42.27/MWh of which was for generation and transmission capacity.[27] At this rate, the customer-generator would receive $16,284 for excess generation at the end of the year. Suppose that this customer could magically determine exactly which five hours would be used in the PJM cost allocation process and decided to "turn off" their generation during only those five hours. Given that PJM's peak hours tend to occur

[26] This is the expected generation using the Company's PVWatts assumptions.
[27] Company workpaper SP-II-5 Attachment A.

between 4 and 6 PM EPT, the 100 kW generator will not be outputting 100 kW, but something lower.[28] The exact value will depend on the weather, but to continue the "worst case scenario", one can assume they may be outputting an average of 56 kW during these hours.[29] If the customer-generator deactivated the generation for these five hours, it would forgo roughly $31 in compensation.[30] In order for the customer-generator to come out ahead as a result of this behavior, the price of the transmission and capacity components of the GSSR-1 rate would have to increase by at least 0.5% as a direct result of the individual customer-generator's actions.[31]

In reality, a customer-generator would not have the magical ability to only deactivate their system during the 5 CP hours as these hours are not known in advance. Instead, a customer-generator seeking to manipulate the market to its favor would have to turn off their system during many summer afternoons between 4 PM and 6 PM with the hopes that one of those days would end up being a 5 CP hour. If they instead picked 20 days during which to target their peak load increase, the forgone revenue would increase by roughly 5 times, which would in turn require the capacity price impact from the customer-generator's actions to be in the 2-3% range to recoup the losses.

Q28. IS THERE ANY EVIDENCE WHATSOEVER OF A COORDINATED EFFORT AMONG ANY, MUCH LESS ALL, OF THE CUSTOMER-GENERATORS TO INTENTIONALLY DEACTIVATE THEIR SYSTEMS DURING PEAK HOURS TO MANIPULATE THE MARKET PRICE OF CAPACITY AND TRANSMISSION SERVICES?

[28] 18 of the past 20 5CP hours occurred either between 4 PM and 5 PM EPT or between 5 PM and 6 PM EPT. https://www.pjm.com/-/media/DotCom/planning/res-adeq/load-forecast/summer-2024-peaks-and-5cps.pdf

[29] The average of the five highest generation hours between 4 PM and 6 PM EPT from June to September in the Company's workpapers for a 100 kW_{AC} system averaged 56.5 kW. This represents the largest increase to peak demand that the customer-generator might expect to make on the 5CP days by shutting down its PV system.

[30] 56 kW * 5 hours * $110.77/MWh = $31.32 in lost revenue.

[31] Returning to the original revenue would require a total PTC of $110.98/MWh, which is $0.21/MWh higher than the original price. This would require a 0.51% increase in the generation and transmission capacity prices.

A28. Of course not. But even if there was, the ability for an individual customer-generator's behavior today to impact future capacity prices is swamped by so many other factors as to be rendered moot.

Q29. HOW MUCH CUSTOMER-GENERATOR SOLAR CAPACITY IS CURRENTLY OPERATING ON THE COMPANY'S GRID?

A29. The Company indicated it has about 4.1 MW of customer-generators in service on its system across all customer sizes and types.[32] Much of this is serving behind-the-meter loads, meaning only a fraction of this capacity would benefit from the hypothetical market manipulation suggested by the Company.

Q30. HOW MUCH LOAD WAS PRESENT DURING THE 2024 5 CP HOURS IN THE PPL PJM ZONE, WHICH SETS THE CAPACITY PRICE FOR THE COMPANY?

A30. The average of the 2024 5CP hours in PPL's PJM zone was 6,928.2 MW.[33]

Q31. WHAT WAS THE RECENT AMOUNT OF OFFERED AND CLEARED CAPACITY IN THE MOST RECENT PJM CAPACITY AUCTION IN THE PPL ZONE?

A31. The PJM PPL zone had 8,424.6 MW of capacity offered and cleared 8,377.4 MW of capacity.[34]

Q32. PUTTING THESE FIGURES TOGETHER, WHAT WOULD HAVE TO HAPPEN FOR A CUSTOMER-GENERATOR'S DECISION TO DEACTIVATE THEIR SYSTEM DURING PEAK HOURS TO IMPACT CAPACITY PRICES TO A SUFFICIENT DEGREE TO MAKE IT WORTH THEIR WHILE?

A32. First, a customer-generator would have to be served on the GSSR-1 tariff and have annual excess energy. This already eliminates any customer with a system that does not produce more energy over the course of the year than their consumption. Then, the customer will have to decide to attempt to manipulate the PJM capacity market by intentionally shutting their system down for several hours during hot summer afternoons.

[32] Exh. KL-7, Company workpaper SP-I-2 Attachment A.
[33] https://www.pjm.com/-/media/DotCom/planning/res-adeq/load-forecast/summer-2024-peaks-and-5cps.pdf
[34] https://www.pjm.com/-/media/DotCom/markets-ops/rpm/rpm-auction-info/2026-2027/2026-2027-bra-report.pdf

Depending on the system size and configuration, this may require the repeated manual flipping of cutoff switches and accepting any additional wear and tear on components that results.

Following this, the customer will have to sit around and wait to see if the day they selected to shut off their system ends up being one of the 5 CP hours on which PJM capacity cost allocations are based. If they missed by even an hour, they would have forgone guaranteed revenue based on speculation. But even if they were right, they would then have to wait several years for the increase in load attributable to their action to be captured via PJM's load forecast methodology and subsequently increase the load obligation of the PPL zone.[35] Next, generation and other capacity resource owners would have to bid in a manner where the marginal increase in PPL zonal load from the foregone solar generation triggers a price increase in the capacity market that exceeds the lost revenue from shutting down their system. Finally, three to four years hence, the customer-generator would have to wait for the end of the year to receive any added compensation for their annual excess generation that their actions has netted them.

Q33. IS THIS IN ANY WAY A REALISTIC SCENARIO?

A33. No; it is instead an absurd one. Putting aside the notion that the Company's small customer-generators will be flipping disconnect switches on hot summer afternoons in an attempt to manipulate the multi-billion-dollar PJM capacity market, the actions of any individual customer-generator would simply be lost among the many thousands of MW of load and generation that set PJM capacity prices. Even if there was a grand conspiracy and all 4.1 MW of customer-generators (including those that do not have any excess annual generation and thus would be completely unmotivated to lose money) turned off their systems during hot summer hours, this would only represent 0.05% of the cleared capacity in the PPL zone and has essentially zero chance of affecting the clearing price.

[35] PJM capacity prices are typically set three years in advance, although the capacity auction schedule has been compressed in recent years.

Q34. WHAT DO YOU RECOMMEND WITH RESPECT TO THIS "CONCERN" RAISED BY THE COMPANY?

A34. I recommend the Commission completely and wholeheartedly disregard it. It is a specious argument that has no basis in rational action by customer-generators and should be summarily dismissed.

D. The Billing Demand Proposal Discriminates Against Customer-Generators in Favor of Non-Customer Generators

Q35. WHAT CHANGES DID THE COMPANY MAKE TO ITS RATE DESIGN IN ITS REBUTTAL TESTIMONY?

A35. The Company modified the billing determinants that it used to calculate the demand charge in the GLP-1 and GLP-3 tariffs to confirm with its proposed Billing Demand definition.[36] In its original application, the Company used the actual and/or ratcheted demand from the customer to calculate the demand rates. When these were updated based on the proposed definition, the total demand billing determinants on the GLP-1 tariff increased by roughly 25%, going from 163,587 kW to 203,588 kW. The GPL-3 tariff had a much smaller increase given the fewer number of customer-generators and relatively larger customer loads on this tariff, increasing from 131,543 kW to 133,103 kW. The increase in billing determinants has an inverse effect on demand rates as they are still designed to recover the same revenue. The GLP-1 rates fell roughly 20% from $4.44/kW to $3.79/kW, while the GLP-3 rates fell modestly from $6.78/kW to $6.71/kW.

Q36. WHAT IS THE PRACTICAL EFFECT OF THIS CHANGE?

A36. The practical effect is that the 13 customer-generators on the GLP-1 tariff will see a massive increase in distribution costs, while the 1,124 non-customer-generators on the GLP-1 tariff will see a non-trivial distribution bill reduction.[37]

Q37. IS IT POSSIBLE TO CALCULATE THE MAGNITUDE OF THIS CHANGE?

[36] Gorman Rebuttal at 4. All figures in this paragraph are from Table HGS-2.
[37] Table HGS-2 indicates 13,644 annual bills, which is 1,137 customers. Workpaper SP-I-2 Attachment A shows 13 current customer-generators take service on the GLP-1 tariff, with a combined rated capacity of 2,967 kW.

A37. It is possible to get a rough estimate, although the Company's figures and discovery responses conflict with each other. Specifically, the increase in the GLP-1 billing determinants due to the inclusion of the GGR (3,333 kW per month) is larger than the sum of the GGR reported for active customer-generators on the GLP-1 tariff (2,967 kW per month). Given many of these customers are BTM generators, their demand under the current definition should not be zero, widening the disparity in the Company's figures.

The Company does not indicate that any of the "in progress" solar projects will take service on the GLP-1 tariff, nor does it include any new GLP-1 customers in its projected test year.[38] Further, after reviewing a confidential discovery response just before filing this testimony that included details about individual GLP-1 net metered customers, the 40,001 kW annual increase used in the bill determinant recalculation is substantially larger than the sum of the incremental Billing Demand in that workpaper.[39] I recommend the Commission investigate this matter further if it accepts the Company's Billing Demand definition to ensure that rates are being calculated correctly.

In my analysis using publicly available data, I attempted to de-skew the average cost impact due to the one very large (1.77 MW) customer-generator currently taking service on GLP-1 by separately analyzing this customer.[40] Using Excel, I set up a set of equations to calculate the average demand of the 1,124 non-customer generators and the 12 remaining customers-generators under the old and new definitions, setting the resulting total demand equal to the values in Table HGS-2. I then used Excel's Solver to solve the equations.[41] The results are found in Table 2 below.

[38] Exh. KL-7. In SP-I-2 Attachment A, all four projects listed as "Applied / In Progress" are listed on rate GLP-3. In the Company's COSS Study (Schedule B2-1), there are no additional customers forecasted for 2025 or 2026.
[39] Citizens' HIGHLY CONFIDENTIAL SP-II-11 Attachment A. I reviewed the workpaper too late to modify the analysis below. That said, the analysis presented here does not utilize confidential data and can thus be publicly filed and is largely consistent with the customer-specific results in the confidential attachment.
[40] Breaking this customer out made it impossible to solve the equations perfectly, although the resulting answer is within roughly 2.5% of the demand totals listed in the Company's rebuttal testimony.
[41] The equations have multiple results depending on the assumed average demand of non-customer-generators and customer-generators. Absent any additional information, I seeded the Solver algorithm with the assumption that the

	Direct Definition			
	Non Cust-Gen	1.77 MW Cust-Gen	Other Cust-Gens	Total
Customers	1,124	1	12	1,137
Avg Demand	12	380	12	
Avg kWh	1,994	0	1,994	
Customer Charge	$21.00	$21.00	$21.00	
Demand Rate	$4.44	$4.44	$4.44	
Energy Rate	$0.01143	$0.01143	$0.01143	
Customer Charge	$21.00	$21.00	$21.00	$23,877
Demand Charge	$53.23	$1,688.20	$53.23	$62,162
Energy Charge	$22.79	$0.00	$22.79	$25,894
Total Monthly	$97.03	$1,709.20	$97.03	$111,933
Total Annual	$1,164.33	$20,510.44	$1,164.33	$1,343,192
	Rebuttal Definition			
	Non Cust-Gen	1.77 MW Cust-Gen	Other Cust-Gens	Total
Customers	1,124	1	12	1,137
Avg Demand	12	1,766	113	
Avg kWh	1,994	0	1,994	
Customer Charge	$21.00	$21.00	$21.00	
Demand Rate	$3.79	$3.79	$3.79	
Energy Rate	$0.00976	$0.00976	$0.00976	
Customer Charge	$21.00	$21.00	$21.00	$23,877
Demand Charge	$45.44	$6,693.14	$427.97	$62,904
Energy Charge	$19.46	$0.00	$19.46	$22,110
Total Monthly	$85.90	$6,714.14	$468.43	$108,892
Total Annual	$1,030.85	$80,569.68	$5,621.18	$1,306,699

Table 2 – Billing Demand Definition Impact on Rates and Bills

Q38. HOW DO YOU INTERPRET THESE RESULTS?

A38. Assuming the Company's discovery responses and calculations are correct (although they do conflict with each other), mathematically the only way for the total demand billing determinants to increase by the 40,001 kW per year from 13 customers is for each customer to see a sizable increase in their assigned billing demand. In all likelihood, the one large 1.77 MW customer-generator represents a sizable portion of the increase, which I estimated at just over 40% of the total.[42] Even when I separately account for this, the

two groups of customers had the same average demand under the current definition. Even if customer-generators have larger-than-average demands, the total bill impact of this change remains similar.

[42] I estimated the average peak demand of this customer assuming a 50% load factor and using the 2022 sales from Workpaper SP-1-14 of 1.66 million kWh, resulting in an average peak demand of 380 kW. This customer's 2024 sales were reduced to 0 kW, suggesting that their solar system is fully offsetting their annual usage.

remaining customer-generators see an average billing demand increase of roughly 101 kW per month.

The impact on the customer-generators is sizable. The single large customer-generator would see its bill increase by more than $60,000 per year, a truly punitive amount and equal to a nearly 300% increase in its distribution bill. The remaining customer-generators would on average see bill increases of about $4,500 per year, representing a nearly 400% increase. Meanwhile, the non-customer generators would on average receive an 11% reduction in their demand charges, despite no change in behavior or usage of the system.

Q39. WHAT POSSIBLE JUSTIFICATION FOR THIS RESULT DOES THE COMPANY PROVIDE?

A39. Despite admitting that customer-generator exports do not always cause an increase in costs, and even if they did, that it has not done the requisite studies to determine those costs, the Company essentially claims that it has been billing customers wrong for as long as it has had customer-generators:

> Q. If the new "obligations" above do not result in incremental costs to serve its customers, does the Company believe it is appropriate to charge the customer-generator more after installing the on-stie generation? Please explain in full.
>
> A. Yes, just as obligations from new or increased load that increase peak consumed demand will result in increased charges to customers—regardless of whether specific, measurable incremental cost increases can be directly correlated to the new load—the Company proposes to charge exported 'demand' in a similar manner. The Company cannot reasonably calculate the exact incremental costs incurred by each individual customer on an ongoing basis, which is one of the reasons why tariffed rates are used. Billing demand and usage provide the best reasonable representation of a customer's relative utilization of the distribution system and, as such, are appropriate quantities on which to base customer bills.[43]

In short, the Company claims that customer-generators place new "obligations" on the system, and that even if these obligations do not increase the cost of the system, it is nonetheless appropriate for customer-generators to pay more for their use of the

[43] Exhibit KL-8, SP-VI-5.c.

system. In the example above, "serving" these new "obligations" results in a typical customer-generator seeing their costs increase by thousands of dollars per year.

Q40. HAS THE COMPANY PERFORMED ANY ANALYSES TO SUPPORT THIS DRAMATIC RESULT?

A40. No. The Company admits that adding customer-generators to its systems "do[es] not always result in incremental cost increases to operate and maintain the system."[44] It admits that customer-generators must pay for required studies and systems upgrades to safely interconnect with the Company's system.[45] It admits that adding distributed generation to its system will never increase feeder peak demand.[46] It admits that it has not performed a cost of service study comparing the cost responsibility using actual metered energy flows or its GGR Billing Demand methodology.[47] It admits that it does not perform marginal cost of service studies for its distribution system specifically related to the marginal cost of exports from distributed generation.[48] Finally, it admits that it is not aware of any other unbundled distribution utility that uses its proposed Billing Demand methodology.[49] In short, it has done none of the legwork required to demonstrate its proposal is just and reasonable.

Q41. DID THE COMPANY IDENTIFY WITH ANY SPECIFICITY WHAT THESE NEW "OBLIGATIONS" ARE?

A41. It specifically noted that customer-generators place new obligations on the system "by exporting more energy than it previously imported, and then expecting the return of the 'banked' excess supply on-demand."[50] It continued, "Finally, the Company does not argue that generation, by nature, creates additional costs compared to consumption of a

[44] Exhibit KL-9, SP-VI-5.b.
[45] Exhibit KL-10, SP-I-19, Exhibit KL-11, SP-I-20.
[46] Exhibit KL-12, SP-V-2.a.iii.
[47] Exhibit KL-13, SP-IV-6.
[48] Exhibit KL-14, SP-IV-23.
[49] Exhibit KL-15, SP-V-3.
[50] Johnson Rebuttal at 23.

similar magnitude. Rather, we seek to treat all utilization of the distribution system equally, regardless of the direction in which power flows"[51]

Q42. WHAT IS THE "RETURN OF THE 'BANKED' EXCESS SUPPLY ON-DEMAND" DESCRIBING?

A42. Physically, it is describing nothing other than the Company providing power to the customer-generator. The power grid does not physically separate excess generation, set it aside, and then return it to the customer-generator at a later time; it meets the instantaneous power needs of the customers at all times. The "banking" concept is strictly related to the net metering accounting rules and is the policy of the Commonwealth. Rather, the Company is describing its obligation to provide its customers with power when called upon, which is a core component of its obligation to serve. It does this the same for customer-generators as it does with non-customer-generators; there is nothing special here in terms of the system usage or subsequent cost-causation of customer-generators.

Q43. HAS THE COMPANY IDENTIFIED ANY SCENARIO IN WHICH THESE NEW "OBLIGATIONS" CANNOT BE HANDLED BY THE EXISTING SYSTEM WITHOUT MODIFICATION?

A43. The Company has not identified any specific issues that directly result from customer-generators being connected to its system. It does mention hypothetical concerns related to power fluctuations from passing clouds, but admits that these types of issues are screened for during the interconnection process, must be remedied and paid for by a customer-generator prior to connecting to the system, and there is "little difference" between solar generation and customer load fluctuation of similar size and timescale.[52]

Q44. DO DISTRIBUTION SYSTEM ASSETS GENERALLY CARE WHICH DIRECTION POWER FLOWS THROUGH THEM?

A44. Generally, no. Poles are structural, not electrical, in nature. Wires are unaffected by the direction of power flow and are only limited by the total power they can carry, and

[51] *Id.*
[52] Exhibit KL-16, SP-III-1.

transformers can typically handle reverse power flows with no impact on operations. There may be some larger switching equipment and voltage control equipment that are not designed to manage two-way flow, but these comprise a small portion of the Company's distribution rate base and the Company has not identified any ratebase-funded upgrades needed to accommodate reverse power flows as those would need to be paid for by the customer-generator as a condition of interconnection.

Q45. IS THE COMPANY'S BILLING DEMAND PROPOSAL REALLY BASED ON "ALL UTILIZATION" OF THE SYSTEM BY ITS CUSTOMERS?

A45. No. For a customer-generator, the Billing Demand is the larger of the peak imported power and the GGR, even if the GGR power equivalent is never actually exported to the grid. Further, the Company has already admitted that its current billing practices are heavily influenced by its use of a 50% demand ratchet, with roughly 50% of customers already being billed not on their actual usage but their ratcheted demand.

Q46. WHAT IS YOUR RECOMMENDATION ON THIS MATTER?

A46. The Company's justification for its Billing Demand proposal is inconsistent and selectively punitive towards customer-generators. It claims that it is proper to base demand charges on "all utilization" for customer-generators, even though it does not do so for non-customer-generators. It claims that customer-generators create additional "obligations" on the system and should thus pay more, despite the complete lack of incremental costs associated with these "obligations." Its updated rate design would increase distribution rates for most non-residential customer-generators by roughly 400% while providing a roughly 11% reduction for non-residential, non-customer-generators, despite no individual customer shifting their behavior in a way that impacts costs. I continue to recommend the Commission reject the Company's Billing Demand proposal as unsupported, not cost-based, and discriminatory towards customer-generators.

E. The Company Misrepresents the Interaction between Customer-Generators and its Default Service Provider Contract.

Q47. WHAT IS ONE OF THE CORE ASSERTIONS OF THE COMPANY IN THIS CASE?

A47. The Company asserts that there is a cost shift that occurs when a customer-generator is paid for its annual excess energy at the GSSR-1 PTC rate.[53] The Company's contends its analysis demonstrates "the limited ability of net-metered [solar PV] to mitigate PJM costs."[54] It continues:

> Additionally, while no quantitative analysis has been performed, basic market principles suggest that as the total volume of energy purchased decreases, the price-per-unit will increase. In essence, as more energy is purchased from net-metered exports, less is purchased through the DSP wholesale contract. This lowers the 'buying power' of the DSP while concentrating non-volumetric (Company and supplier admin costs, Capacity, Transmission, and RTEP) costs across a smaller total quantity purchased, increasing the cost per MWh of default supply.
>
> Finally, as purchased net-metered energy creates net under collection of GSSR costs under the existing structure (where the customer generator receives the GSSR-1 price regardless of the generator's size), the resulting reconciliation in future periods through the E-factor inflates the cost of default supply which, in turn, inflates the purchased cost of future-period net-metered energy purchases. In short, net-metered customer-generators directly benefit from the price inflation that they cause in a compounding fashion that increases as more net-metered generation is installed.
>
> The Company concludes from its analysis that 1) net-metered generation exports result in a significant increase to default supply costs and 2) its proposed tariff change will mitigate these increases by shifting large exporters to the GSSR-2 rate and corresponding reimbursement formula.[55]

Q48. PLEASE DISCUSS YOUR UNDERSTANDING OF THE COMPANY'S DSP CONTRACT.

A48. Based on a review of the recent DSP docket and discovery responses from the Company, it is my understanding that the Company has engaged a wholesale electricity supplier in a "Load-Following Full Requirements contract."[56] The contract requires the supplier to

[53] Exhibit KL-17, SP-II-5 Revised.
[54] *Id.*
[55] *Id.*
[56] Joint Default Service Plan for Citizens' Electric Company of Lewisburg, PA and Wellsboro Electric Company For the Period June 1, 2025 through May 31, 2029 at 1, Docket Number P-2024-3049357, May 31, 2024. ("DSP Plan Application")

deliver all necessary energy to the Company's PJM pricing node and allows the supplier to directly pass through many costs, including those for transmission and generation capacity and PJM's Regional Transmission Expansion Plan/Transmission Enhancement Costs ("RTEP/TEC"). It prices energy using a six-month laddered approach, where a 12-month strip of forward prices for the monthly PJM West Hub on-peak price are triggered every six months for half of the anticipated load.[57]

The contract also includes a "Supplier Adder", which includes the following:

> The Supplier Adder covers all other costs to deliver default service power (both fixed and hourly energy) to the wholesale meter at the Citizens' or Wellsboro Aggregate Bus. This includes congestion, marginal losses, Alternative Energy Portfolio Standards ("AEPS") Act compliance, and transmission losses, as well as all risks associated with default service customer usage variability, customer migration (switching to an EGS for supply service or returning to default service as permitted under the Companies' tariffs and Pennsylvania law) and deviations between the forward pricing and actual costs.[58]

The Company elaborated on the purpose of the Supplier Adder:

> On top of the respective energy component charges, Citizens' and Wellsboro will pay a Supplier Adder* to their wholesale supplier, which will be a uniform cents-per-kWh charge fixed for the duration of the 4-year contract. The Supplier Adder will compensate the wholesale suppliers for all costs and risks for delivery to the wholesale meter for the Citizens' or Wellsboro Aggregate Bus, including marginal losses, ancillary services, congestion, transmission charges (other than NITS and RTEP/TEC), AEPS costs, marginal losses, customer load variability, and customer migration. Importantly, the Supplier Adder avoids the need for the Companies to maintain congestion management plans, as wholesale suppliers would continue to assume congestion costs and the associated rights to Auction Revenue Rights "ARR" and Financial Transmission Rights "FTR".
>
> *The Supplier Adder will place the risk of deviations in actual versus forward energy costs, sales, on-peak/off-peak customer usage and on-peak/off-peak wholesale pricing differentials on the wholesale supplier.[59]

Q49. HAS THE COMPANY'S LATEST DSP PLAN BEEN APPROVED?

[57] DSP Plan Application at 12.
[58] *Id.*
[59] *Id.* at 14.

A49. Yes. The Company's DSP Plan was approved by the Commission on January 23, 2025, and will be in effect from June 1, 2025, through May 31, 2029.[60] Unless subsequently modified by agreement of all parties, the pricing methodology and Supplier Adder will be locked in for the next roughly four years.

Q50. GIVEN ALL OF THE COSTS AND RISKS THAT ARE INCLUDED IN THE SUPPLIER ADDER, HOW MUCH DID THE WINNING BIDDER OF THE CONTRACT CHARGE FOR THIS ITEM?

A50. The winning bidder not only did not charge a premium for the Supplier Adder, it offered and won with a Supplier Adder credit of $2.66/MWh.[61] In other words, for every MWh that the supplier bills the Company for default service, it reduces the cost by $2.66/MWh.

Q51. HOW DOES THIS COMPARE TO THE SUPPLIER ADDER IN THE PRIOR DSP PLAN?

A51. The Supplier Adder in the prior DSP period from June 1, 2021, through May 31, 2025, was $1.37/MWh.[62] In this procurement, the winning bidder had a Supplier Adder that was $4.03/MWh lower, a considerable drop from the prior plan.

Q52. DID THE COMPANY MAKE ANY STRUCTURAL CHANGES TO THE CURRENT DSP PLAN THAT MIGHT HAVE IMPACTED THIS FIGURE?

A52. Potentially. The Company requested and was approved a "minor modification" to the energy pricing formula trigger date.[63] Instead of providing notice to the supplier on a day-ahead basis, the Company switched to a same-day trigger process. This reduces the risk that market prices move substantially between when the trigger is executed and when the actual prices are locked in.

Q53. DO YOU BELIEVE THIS MODIFICATION WAS RESPONSIBLE FOR A MEANINGFUL PART OF THE REDUCTION OF THE SUPPLIER ADDER?

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[60] Commission Order, Dockets P-2024-3049357, January 23, 2025.
[61] Citizens' Electric Company of Lewisburg, PA Generation Supply Service Rate Filing; Supplement No. 171 to Tariff Electric PA. P.U.C. No. 14; Docket No -2024-3049357
[62] Citizens' Electric Company of Lewisburg, PA Disclosure of Default Service Solicitation Results June 1, 2021 through May 31, 2025. Available at https://citizenselectric.com/wp-content/uploads/2021/04/Citizens-2021-Default-Service-Supply-Bid-Disclosure-A8029446.pdf
[63] DSP Plan Application at 13.

A53. It is obviously not possible to determine exactly what thought process the winning bidder used in setting its Supplier Adder, but one can examine the degree to which PJM monthly forward contracts change in price on a day-to-day basis. In reviewing data on CME Group's website, while there were some days which future contract prices changed by several $/MWh on subsequent days, most days saw much smaller changes measured in the cents/MWh.[64] As such, it is unlikely that this change alone resulted in the sizeable drop of the Supply Adder in this procurement.

Q54. WERE THE ISSUES THAT ARE AT PLAY IN THIS DOCKET PRESENT DURING THE TIME WHEN BIDDERS WERE PARTICIPATING IN THE DSP PROCUREMENT PROCESS?

A54. Yes. The Company's DSP Plan was not approved until the end of January 2025. The ability of large customer-generators to produce substantial amounts of excess generation and be compensated on the GSSR-1 tariff was in place at that time. In fact, the Company did not file the application in this docket until April 30, 2025, which was after its compliance filing on April 17, 2025, in the DSP Plan reporting the results of the finalized procurement.

Mr. Johnson testified that the Company "did not provide any party or customer with advanced briefings on the various proposals or content of the rate filing until it was submitted."[65] In other words, the suppliers that bid in the DSP Plan procurement in early 2025 would have had no public knowledge at the time of the Company's plan to modify its default supply classification process.

Q55. DID ANY PARTY DISCUSS THE POSSIBILITY THAT SUPPLIERS WOULD ADD A LARGER "RISK PREMIUM" TO THEIR BIDS BECAUSE OF SOME OF THE RISKS ASSOCIATED WITH CUSTOMER-GENERATORS AND NET METERING?

[64] Several different futures contracts were examined roughly a year before their covered date at https://www.cmegroup.com/markets/energy/electricity/pjm-western-hub-peak-calendar-month-real-time-lmp.quotes.html

[65] Johnson Rebuttal at 34.

A55. Yes. While discussing the UGI Electric Default Service Plan order in his rebuttal testimony, OCA Witness Zach Teti noted that UGI raised three issues related customer-generators and its DSP procurement:

> (1) their output would decrease GSR-1 group load and tranche size; (2) there is substantial question as to the level of output and timing of when these projects will become operational; and (3) these large customer-generators have the ability to leave default service at any time and participate in the wholesale market, thereby creating an attrition risk if projects opt to leave GSR-1 service and shop their output elsewhere.[66]

In his own discussion of this issue, Mr. Teti stated

> While the Company did not show this effect in their analysis, the Company and I share the concern about the risk premiums associated with customer-generator uncertainty described in the above excerpt of the PUC's Opinion and Order. In the above remark, the Company expresses a comparable concern: that a large customer-generator stands to benefit from "price inflation that they cause in a compounding fashion." I take this statement to mean that the large customer-generator (output capacity > 400 kW) stands to benefit from higher prices caused by the risk premiums added to DSP suppliers to address their risks caused by unknown output quantities and attrition risk of large customer-generators.[67]

Q56. BASED ON THE LATEST DSP PROCUREMENT, DOES THIS SEEM TO BE AN ONGOING CONCERN?

A56. No. The most recent DSP procurement for the Company resulted in a substantial decrease in the Supplier Adder, which includes, among other things, all the risks identified in the UGI order above. The winning bidder was clearly sufficiently comfortable, even with those open issues, to undercut the prior Supplier Adder by more than $4.00/MWh. Further, even if suppliers were concerned about these developments, the Company's customers will be served for nearly four years before the issue will come up again. Given the myriad changes to the PJM market, including data center load growth, state and federal policy changes, and market design reforms that are likely to occur over the coming four years, there will be many other issue that will impact future DSP procurements than just those issues being addressed in this case.

[66] Teti Rebuttal at 11, quoting the PUC Decision in Docket P-2024-3049343 at 23.
[67] Teti Rebuttal at 12.

Q57. RETURNING TO THE INTERACTION OF THE DSP CONTRACT AND THE POTENTIAL COST IMPACT OF CUSTOMER-GENERATORS TAKING SERVICE ON THE GSSR-1 TARIFF, WHAT ANALYSIS DID THE COMPANY PRODUCE?

A57. The Company produced an analysis that purported to show that a 400 kW_{AC} rooftop system with no offsetting load could increase DSP costs by roughly $27,000 per year, while a 3 MW_{AC} ground mount single-axis tracking system with no offsetting load could increase DSP costs by $230,000 per year.[68] In calculating these figures, the Company assumed that it pays the full retail PTC to customer-generators for their excess energy, but only offsets the energy portion of the DSP contract when that generation reduces the energy that the wholesale supplier must provide to the Company. In other words, it provides zero value for any offset of generation capacity, transmission capacity, or RTEP/TEC costs, all of which are based on the peak load being provided by the wholesale supplier.

Q58. WHAT JUSTIFICATION DID THE COMPANY PROVIDE FOR THIS APPROACH?

A58. It provided four explanations, summarized below:

- NEM systems are not dispatchable
- GSSR-1 customers benefit from high PTC costs, providing an incentive to increase the costs
- Solar systems have a low demonstrated coincidence with peak demand periods.
- NEM generation is volatile and impacted by weather.[69]

Based on these factors, the Company "does not believe it is appropriate to incorporate any capacity or transmission impact into its analysis, however, because net-metered generation does not guarantee those savings and is economically disincentivized to export during peak demand periods."[70]

Q59. DO ANY OF THESE FACTORS MATTER IN TERMS OF HOW THE DSP CONTRACT IS STRUCTURED?

[68] Exhibit KL-17, SP-II-5 Revision 1.
[69] Exhibit KL-18, OCA-XV-1.
[70] Exhibit KL-19, OCA-XV-2.

A59. No. The fact that NEM systems are not dispatchable is irrelevant. The wholesale supplier is responsible for dispatching the anticipated DSP load on a day-ahead basis through the PJM scheduling process.[71] If the supplier chooses, it can include expected generation from customer-generators in its load assumptions. During the settlement process, any differences between scheduled and actual load are reconciled. All risks associated with any load variability from the DSP customers falls on the supplier and is one of the enumerated components of the Supplier Adder discussed above. This includes any failure to accurately forecast net load and any costs that may be needed to reconcile that load in the real-time market.

The remaining points do not support the Company's conclusion that solar should be afforded zero credit against PJM capacity costs. Because the customer-generators are connected to the distribution grid "downstream" of the PJM settlement point, and because the quantity of net metering capacity is substantially lower than the peak demand of the Company, every kW of power that is produced on the Company's distribution grid is consumed on the Company's distribution grid by another customer. As such, every kW of power that is being generated during one of the five coincident peak ("5CP") hours that determines cost allocation in the PJM market will reduce the amount of capacity that is assigned to the wholesale supplier. Given that the supplier passes these costs directly through to the Company, there is a 1:1 reduction in load obligations based on the generation in those hours.[72]

Q60. DO CUSTOMER-GENERATORS HAVE TO BE PRODUCING AT 100% OF THEIR GGR TO REDUCE PJM COSTS?

A60. No. The Company's argument that solar is intermittent and may not be producing during peak hours has nothing to do with the post hoc analysis that PJM uses to allocate costs. If

[71] Exhibit KL-20, SP-VI-17.

[72] There is a one year delay in when these reductions impact the load obligation, but they will be fully reflected in the PTC for the following energy year.

the system was producing power during a 5CP hour, it will be credited for that power, regardless of the ex ante probability of the generation during that 5CP hour.

Q61. HAVE YOU REVIEWED THE COMPANY'S ANALYSIS SUGGESTING THAT SOLAR IS POORLY CORRELATED WITH PEAK HOURS?

A61. Yes. As with the Company's other analysis that I discussed in my direct testimony, it contains a number of errors and improper methodological choices that artificially depress the result.

The Company was made aware of one such mistake where it improperly accounted for the AC to DC ratio of the system and issued a revised workpaper.[73] However, several other methodological issues remain. First, the Company again failed to adjust its modeled solar generation for Daylight Saving Time. For most of the year, this resulted in using solar generation from an hour later than was appropriate, and given the PJM 5CP hours tend to fall during late summer afternoons, this had a sizable impact on the forecasted generation.

Second, in using PVWatts, the Company utilized a typical meteorological year ("TMY") weather file for its modeled generation. TMY files are comprised of actual weather data from many different years that are specifically selected to represent "typical" weather conditions over the full year. The result of simulated generation using TMY files is more likely to represent the long-term average generation in a given location, but it is inappropriate to use when analyzing generation on a specific day at a specific time.

The PJM systems tends to peak during hot, summer afternoons. Hot summer afternoons are often sunny, meaning that solar production may be above average for that time of year. If the TMY file contained July weather from 2007, then the generation using that weather file on July 27th, 2007 at 5 PM EPT will not match the weather

[73] Exhibit KL-17, SP-II-5 Revision 1.

conditions that led to July 27th, 2023 at 5 PM EPT to be a 5CP hour. A proper analysis must include weather that corresponds to the grid conditions in place at the time.

Finally, the Company's analysis includes 5CP data going back to 2015, but fails to recognize what is a clear trend in the transmission cost allocation hours. Between 2015 and 2019, 18 of the 25 5CP hours for transmission cost allocation occurred during non-summer months. But between 2020 and 2024, only 4 of the 25 hours occurred outside the summer.[74] PPL, the transmission system in which the Company operates, is clearly shifting from winter to summer, and as a result, including data from the winter months from 10 years ago in the performance average is no longer appropriate.

Q62. WERE YOU ABLE TO FIX THE COMPANY'S ANALYSIS?

A62. Yes. I used the National Renewable Energy Laboratory's System Advisor Model ("SAM"), which is a more sophisticated version of its PVWatts tool, to replicate system generation using actual weather files from 2015 through 2024.[75] I fixed the Daylight Saving Time issue and recalculated the average performance during the 5CP hours from the past five years. The results are found below in Table 3.

	400 Kw Fixed Tilt		**3 MW Tracker**	
% of Nameplate during 5CP Hours	PLC Gen. Capacity	NSPL Trans. Capacity	PLC Gen. Capacity	NSPL Trans. Capacity
Original	25.4%	20.9%	39.9%	27.2%
Corrected	41.8%	35.0%	65.2%	50.1%
Change	**164.6%**	**167.4%**	**163.7%**	**184.0%**

Table 3 – Average Solar Contribution during 5CP Hours 2020-2024.

Q63. HOW DO YOU INTERPRET THESE RESULTS?

A63. The corrections increased the Company's original solar capacity contribution values by 64% to 84%. Further, the corrected results demonstrate that solar PV provides meaningful generation during the 5CP hours for both generation and transmission cost

[74] Exh. KL-17, SP-II-5 Attachment B
[75] https://sam.nrel.gov/

allocation purposes, particularly for the 3 MW tracking system. It is correct that these values are lower than the GGR of these systems, but these values are more than sufficient to discredit the Company's position that solar should get no capacity reduction credit for generation and transmission costs.

Q64. HOW DO YOU ANTICIPATE THE COMPANY RESPONDING TO THIS ANALYSIS?

A64. I suspect they will acknowledge the methodological shortfalls of their original analysis, but would still argue that because solar has a relatively low capacity factor and is not perfectly correlated with the 5CP hours, it is still causing a cost shift when paid the full PTC.[76]

Q65. DO YOU HAVE ANY ADDITIONAL INSIGHT INTO THAT ISSUE?

A65. Yes. It is important to consider the implications of the result. In the location simulated by the Company, solar production from a single-axis tracker is on average 18.8% of its GGR over the course of a year, while that of a fixed-tilt system is 16.7% of its GGR over the course of a year.[77] But during the peak hours, generation is 2-2.5 higher for fixed-tilt systems, and 2.7-3.5 times higher for single-axis tracking system. In other words, the solar systems outperform during peak hours compared to the total number of MWh they generate.

This has meaningful implications for the Company's PTC contract. In the Company's DSP Plan Compliance Filing, it broke down its calculation for the PTC.[78] Energy costs are calculated based on monthly forward pricing from PJM Western Hub futures contracts. Generation and Transmission capacity costs are converted from dollars to a $/kWh rate by multiplying the total capacity obligation in MW, the corresponding

[76] The Company may also disagree on the appropriateness of using only the past 5 years to reflect the shift in transmission peaks to the summer months. However, the trend in the data is clear, and given that cost allocation is based on actual and not projected data, I continue to recommend this adjustment.
[77] Exh. KL-17, SP-II-5 Attachment B (REV). The Company modeled zip code 17837. The values above represent the capacity factor of solar in that location.
[78] GSSR-1, GSSR-2 ADJ; SUPP NO 171 TO PA PUC NO 14; EFF: 6/1/25 - CITIZENS' ELECTRIC CO OF LEWISBURG, Docket No. P-2024-3049357. ("DSP Plan Compliance Filing") Available at https://www.puc.pa.gov/pcdocs/1875351.pdf

capacity rate in $/MW-day, and the number of days in a year, and finally divided by the total forecasted sales.

The Company performs these calculations for its projected PTC for June 1, 2025, through November 30, 2025, but also includes sales forecast data through May 30, 2026.[79] As such, it is possible to compare the avoided cost value of the generation profile of a fixed-tilt and single-axis tracking solar system against the cost of serving the load profile of the entire DSP load.

Q66. DID YOU PERFORM THESE CALCULATIONS?

A66. Yes, I did. I used solar generation from the TMY weather file for the avoided energy cost calculations given this analysis is for an unspecified period of time. I also used my updated generation and transmission capacity contribution calculations discussed above to calculate the avoided capacity cost values. The results of this calculation are shown below in Table 4.

	400 kW Fixed Tilt	3 MW Tracker	GSSR-1 Load Forecast
Annual Generation / Load MWh	567.9	5,333.2	114,007.0
Gen Capacity Contribution	41.8%	65.2%	
Gen Capacity MW	0.17	1.96	22.86
Gen Rate $/MW-Day	$270.43	$270.43	$270.43
Gen $	$16,487	$193,182	$2,255,947
Gen Rate $/MWh	**$29.03**	**$36.22**	**$19.23**
Trans Capacity Contribution	35.0%	50.1%	
Trans Capacity MW	0.14	1.50	24.90
Trans Rate $/MW-Day	$297.57	$297.57	$297.57
Trans $	$15,221	$163,290	$2,704,465
Trans Rate $/MWh	**$26.80**	**$30.62**	**$23.05**
Energy Rate $/MWh	**$66.82**	**$66.82**	**$66.82**
Total Rate $/MWh	**$122.66**	**$133.66**	**$109.10**

Table 4 – Solar Avoided Cost vs. DSP Load Profile Cost

Q67. HOW DO YOU INTERPRET THESE RESULTS?

[79] DSP Plan Compliance Filing, Schedules 1-12. The energy price for the second 6-month period will change when the new 12-month future contract is locked in. However, the analysis uses the currently 12-month future strip for the analysis as this is the only value available at this time.

A67. The analysis above duplicates the cost for the wholesale supplier of serving a load profile that is identical to the generation profile of the two solar systems. I followed the same steps to calculate the resulting $/MWh rate using the relative quantities of energy, generation capacity, and transmission capacity.[80] The result shows that the cost of serving the solar generation "load profile" is higher than the cost of serving the DSP load profile. Of course, this means the inverse is true: avoiding energy and capacity due to the solar generation profile is worth more than the average cost to serve the DSP load profile.

For the 400 kW_{AC} fixed-tilt system, I calculated an avoided cost benefit of $122.66/MWh, which is $13.56/MWh or 12% higher than the corresponding PTC components cost of $109.10/MWh. For the 3 MWAC tracking system, the avoided cost benefit was even higher at $133.66/MWh, which is $24.57/MWh or 23% higher than the corresponding PTC components. In short, paying customer-generators the PTC for their solar generation does not cause a cost shift to non-solar customers, it in fact undercompensates the solar system's contribution to reducing costs.

Q68. THE FIGURES ABOVE ARE BASED ON YOUR ADJUSTMENTS TO SOLAR'S CAPACITY CONTRIBUTION. WHAT IF THE COMMISSION DISAGREES WITH SHORTENING THE TIME HORIZON TO FIVE YEARS?

A68. If one only corrects the clear methodological errors of the Company's analysis of failing to adjust for Daylight Saving Time and using actual weather data from each year, but still uses the full 10-year average that the Company used, the result is directionally the same. The avoided cost benefits fall slightly to $116.67/MWh for the fixed-tilt system and $125.62/MWh for the tracking system, but these are still comfortably above the corresponding PTC component rate of $109.10/MWh.

[80] I did not include the RTEP/TEC costs as these are minor ($0.94/MWh) and the DSP Compliance Plan did not describe the calculation methodology. I also did not include the Admin costs, which are also minor ($1.35/MWh) and would be skewed by the relatively small quantity of solar generation. Finally, I did not include any distribution loss adjustment as it was unclear whether the Company's load forecast already included this value or not when calculating the final $66.82/MWh rate.

Q69. BUT IF SOLAR IS NOT PRODUCING AT ITS FULL GGR DURING THE PEAK HOURS, AND HAS A LOWER CAPACITY FACTOR THAN THE COMPANY'S DSP LOAD FACTOR, HOW DO YOU EXPLAIN THE ABOVE RESULT?

A69. Another way to analyze the avoided cost benefits is to look at the relative share of each PTC component on a dollar basis. As shown below in Figure 2, the solar generation profiles are "overweighted" in capacity compared to energy. This reflects solar's higher-than-average generation during the 5CP hours compared to the total quantity of generation over the course of the year when compared to the same peak load / total energy ratio of the DSP load profile. The result of this is that outsized avoided capacity benefits are "concentrated" into a small number of annual generation MWh, resulting in the higher rates above.

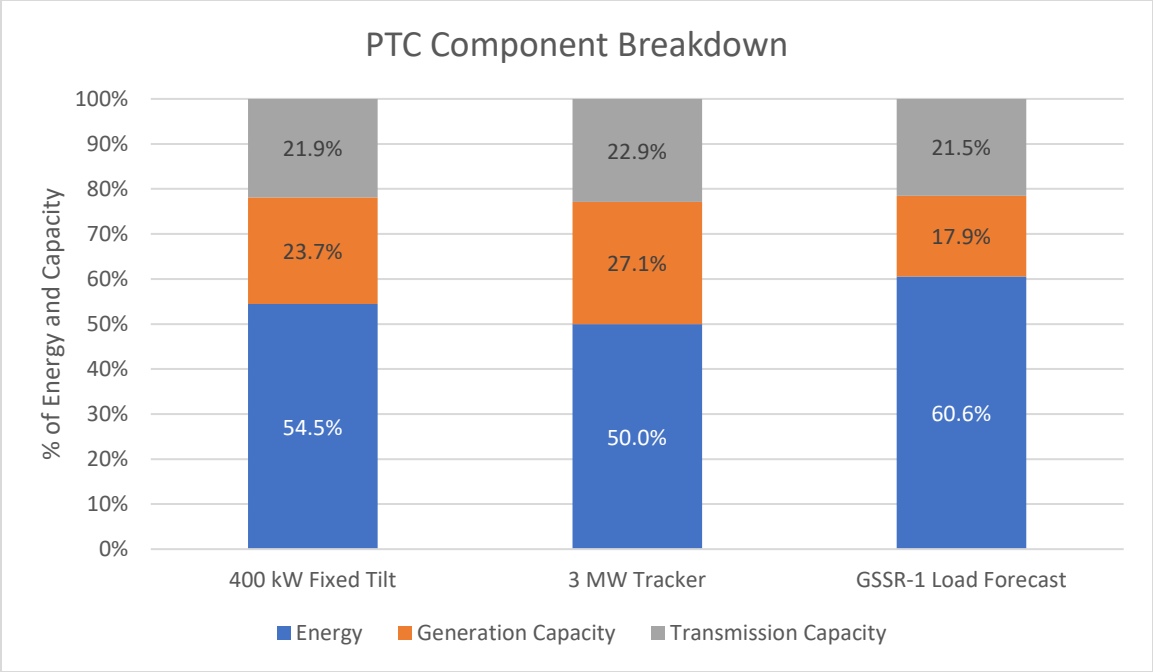

Figure 2 - PTC Component Breakdown

Q70. BUT DOESN'T THE LOWER AMOUNT OF GENERATION FROM A SOLAR SYSTEM IMPROPERLY INFLATE THE SOLAR RATE CALCULATION COMPARED TO THE LOAD PROFILE RATE CALCULATION?

A70. No. Although one might think that dividing the avoided capacity cost benefits by a smaller number of MWh artificially inflates the rates above, there is a simple way to prove this is not true: comparing the cost to serve the DSP load with and without a solar generator.

Because of the capacity cost pass-through and energy cost index structure of the DSP contract, the Company is only obligated to pay for the actual energy and capacity that its DSP customers use. If they use less energy because of distribution-connected solar systems, then the wholesale supplier has to deliver less of this product. If they have lower demand during the 5CP hours because of solar generation, the capacity cost allocation will be proportionately lower. The specific ratio of these decreases will determine whether the overall PTC rate increases or falls as it will be calculated based on the total capacity dollars divided by the total sales.[81]

Q71. WHAT IS THE RESULT OF THIS ANALYSIS?

A71. The results are shown in Table 5 below for the GSSR-1 load net of the fixed-tilt and tracking system. As expected, the rate to serve the GSSR-1 load net of either solar system is lower than the rate to serve the GSSR-1 load by itself, and the rate to serve the load net of the tracker is lower than to serve the load net of the fixed tilt. This is due to the greater reduction in capacity costs than the reduction in total energy in both, but a more pronounced difference in the tracker.

[81] Because of the contract structure, the energy component of the PTC rate remains constant regardless of the number of sales.

	GSSR-1 Load Forecast	Load Less Fixed Tilt	Load Less Tracker
Annual Load MWh	**114,007**	**113,439**	**108,674**
Gen Capacity MW	22.86	22.69	20.90
Gen Rate $/MW-Day	$270.43	$270.43	$270.43
Gen $	$2,255,947	$2,239,460	$2,062,765
Gen Rate $/MWh	**$19.23**	**$19.18**	**$18.42**
Trans Capacity MW	24.90	24.76	23.40
Trans Rate $/MW-Day	$297.57	$270.43	$270.43
Trans $	$2,704,465	$2,443,970	$2,309,406
Trans Rate $/MWh	**$23.05**	**$20.93**	**$20.62**
Energy Rate $/MWh	**$66.82**	**$66.82**	**$66.82**
Total Rate $/MWh	**$109.10**	**$106.93**	**$105.86**

Table 5 – DSP Load Profile Net of Solar Generation

Q72. THE ANALYSIS ABOVE ASSUMES THAT THERE IS NO LOAD TO OFFSET THE PV SYSTEM. DOES THIS ANALYSIS CHANGE IF THESE ARE BTM SYSTEMS THAT ARE INSTEAD OFFSETTING LOAD?

A72. No. The DSP contract is for delivery of all aggregated load at the Company's 69 kV St. Mary's substation.[82] Whether customer-generator uses this energy onsite or exports it to serve its neighbor's load, the net result at the St. Mary's substation is a reduction equal to the solar generation plus distribution line losses.

Q73. THE COMPANY CLAIMS THAT CUSTOMER-GENERATORS WILL BENEFIT "IN A COMPOUNDING FASHION" THROUGH THE INTERACTION OF NETTING ENERGY AND THE GSSR-1 RECONCILIATION FACTOR.[83] DO YOU AGREE WITH THIS STATEMENT?

A73. No, I do not. First, it is important to understand the scale of the DSP contract cost and the potential under-collection due to excess annual energy. The Company reported that customer-generators had accumulated a grand total of 636 MWh of net excess energy at the end of energy year 2025.[84] Even assuming that 100% of these customers are served on the GSSR-1 tariff, at the current PTC of $114.19/MWh, this represents payouts of

[82] DSP Plan, Exhibit NJ-3 at 3.
[83] Exhibit KL-17, SP-II-5 Revision 1.
[84] Exhibit KL-21, SP-IV-13.

approximately $73,000. By contrast, the DSP Plan is projected to collect roughly $13 million in energy year 2026.[85] Even if this excess energy caused a shortfall to be collected in future periods, it would only increase the rate from $114.19/MWh to $114.83/MWh. Given the average commercial customer with excess annual energy only had 58 MWh of banked generation at the end of the year, the reconciliation adjustment discussed above would on average result in an extra $35 or so.[86] This is hardly noticeable compared to the sizable increase these customers would experience under the proposed Billing Demand definition.

More to the point, the Company should be including anticipated generation from customer-generators in the sales forecast used to calculate the GSSR-1 capacity components. If the Company correctly includes these values for its existing and in-progress fleet, then the only potential under-collection due to unplanned excess generation would be from new systems that were conceived and built within the energy year and resulted in excess annual generation for the customer-generator. Given the Company updates its PTC every six months, this is an extremely unlikely scenario.

Finally, even if there were unplanned excess generation that resulted in under-collections in the GSSR-1 account, as shown above, that generation will contribute more to reducing capacity costs than reducing energy sales. When the following year's load obligations are released, they will be lower than they would have been absent the solar generation, which will reduce costs for all customers on the GSSR-1 tariff.

III. REBUTTAL OF OCA WITNESSES ZACH TETI

Q74. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

[85] DSP Plan Compliance Filing, Schedule 3. The Company forecasts 114,007 MWh of GSSR-1 sales at $114.19, which would result in collections of $13,018,459.
[86] Exhibit KL-21, SP-IV-13. There were 10 commercial customers with a total of 577 MWh of excess energy.

A74. In this section of testimony, I discuss the rebuttal testimony of OCA witnesses Zach Teti.[87]

Q75. PLEASE SUMMARIZE THE RELEVANT POSITIONS OF OCA'S REBUTTAL TESTIMONY.

A75. OCA witness Mr. Teti supports the approval of the Company's Billing Demand proposal, indicating his belief that the "overall default service supply portfolio and the specific default service procured on behalf of residential customers would benefit from the Company's proposed Billing Demand methodology."[88]

Q76. DOES MR. TETI PROVIDE ANY INDEPENDENT ANALYSIS OR REASONING TO SUPPORT HIS RECOMMENDATION?

A76. No. Mr. Teti repeats the Company's position, but does not independently discuss or analyze the Billing Demand proposal.[89] In doing so, he adopts the Company's arguments but does not offer any new insight or critiques of those arguments. For instance, he does not discuss the problems with charging customers for demand that they do not place on the system, nor does he question the Company's analysis provided in SP-II-5 Attachment A. In follow up discovery, Mr. Teti admitted that he "did not independently validate the quantitative approach by reconciling/cross-checking monetary values and magnitude of costs."[90] Given the myriad errors identified in the latter analysis in my direct testimony, Mr. Teti's failure to scrutinize the workpapers may have contributed to his acceptance of the problematic results.[91]

Mr. Teti was not able to independently validate the Company's explanation of how demand reductions from customer-generators impact PJM wholesale costs because of some ambiguity in the Company's discovery responses.[92] Mr. Teti did submit

[87] OCA Statement No. 5R - Rebuttal Testimony of Zach Teti on Behalf of the Pennsylvania Office of Consumer Advocate ("Teti Rebuttal").
[88] Teti Rebuttal at 3.
[89] Teti Rebuttal at 6.
[90] Exhibit KL-22, OCA Response to Solar Projects I-2.
[91] See e.g. Solar Projects' Statement No. 2, Direct Testimony of Kevin Lucas at 9-12 ("Lucas Direct").
[92] Teti Rebuttal at 10, footnote 13.

discovery to follow up on this issue, but it was not received before the filing deadline for his rebuttal testimony.

Q77. HAS THE COMPANY SINCE PROVIDED RESPONSES TO MR. TETI'S DISCOVERY?

A77. Yes, they have.[93]

Q78. AND DID THE DISCOVERY CLARIFY THE ISSUE?

A78. No, it did not. Mr. Teti asked the company "Please refer to "Attachment A (Rev)" of Citizens' response to SP-II-5, specifically in the portion that states: 'PJM costs substantially unaffected by net metered sales.' Please explain the effect of net metered sales on PJM costs."[94]

The Company's response did not address the core issue: how do net metered sales, including excess generation from both customer-sited behind-the-meter ("BTM") systems and distribution-connected commercial scale the PJM settlement process and the default service provider's ("DSP") full requirements contract. Instead, the Company reiterated its generic observations about net metered solar; namely, that it is not dispatchable, that solar generation does not peak at the same time as the system peak, and that excess generation is volatile.[95]

Q79. ARE THESE OBSERVATIONS RELEVANT TO THE MECHANICS OF THE PJM SETTLEMENT PROCESS AND THE DSP CONTRACT?

A79. No, they are not. The lack of dispatchability does not matter; these are not capacity resources that must have a specific capacity accreditation in the PJM wholesale market and are held accountable for their output during peak days. The observation that solar generation does not peak during the system peak hours does not mean that solar cannot and does not provide peak demand reductions; it does, albeit at a level that is lower than the GGR of the system. Similarly, the day-to-day volatility of an individual solar generator is smoothed out across a wider geographic area, and system operators

[93] Exhibit KL-18, Citizens' response to OCA-XV-1.
[94] Id.
[95] Id.

understand that solar generation has a diurnal generation profile and can plan the system around this fact.

Q80. WHAT APPEARS TO BE OCA'S MAIN CONCERN RELATED TO THE OPERATING CHARACTERISTICS OF DISTRIBUTION-CONNECTED DG SYSTEMS?

A80. Mr. Teti notes a concern that DSP providers will increase their bids to reflect a "risk premium" associated with the distribution-connected DG systems.[96] He also notes a Company concern about large customer-generators "benefiting from 'price inflation that they cause in a compounding fashion.'"[97] Notably, neither of these concerns has anything to do with the establishment of base distribution rates, which is ostensibly the purpose of this proceeding. They are exclusively related to the issue of DSP procurement, which should be litigated in a DSP proceeding. This proceeding is simply the wrong forum to address DSP-related matters.

Q81. HAS OCA PERFORMED ANY ANALYSIS RELATED TO THE PURPORTED UPWARD PRESSURE ON BIDS CAUSED BY THIS RISK PREMIUM?

A81. No, it has not for the understandable reason that "OCA is not permitted to see bid details following the completion of default service procurement auctions."[98] It is problematic that the office responsible for representing consumers in front of the Commission is not able to investigate one of the more speculative elements supporting a large change to customer-generator compensation.

Q82. ARE THERE OTHER ISSUES THAT MR. TETI RAISES REGARDING THE COMPANY'S TESTIMONY AND TARIFFS?

A82. Yes. Mr. Teti notes several instances of ambiguity and lack of clarity in the Company's testimony, discovery responses, and tariffs regarding how PJM costs are impacted by distribution-connected DG systems.[99] The follow-up discovery that Mr. Teti asked did

[96] Teti Rebuttal at 12.
[97] Teti Rebuttal at 12.
[98] Exhibit KL-22, OCA Response to Solar Projects Set I-3.b
[99] Teti Rebuttal at 16.

not resolve these issues, and it appears the record continues to lack clarity on how exported generation is incorporated into the PJM settlement process and how that impacts DSP costs.

Q83. DO YOU AGREE THERE IS A LACK OF CLARITY?

A83. Yes. I do not believe that the Company has directly answered OCA's questions on this matter, as discussed above. This is yet another reason that issues related to DSP costs should be fully litigated in a DSP proceeding where parties could properly clarify the record on these issues. Making a decision in this rate case docket while key questions related to supply costs for the DSP remain unanswered would be improper.

Q84. DOES THIS CONCLUDE YOUR TESTIMONY?

A84. Yes, it does.

REVISED

Statement No. 2-SR, Surrebuttal Testimony of Kevin Lucas

(Clean Copy)

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	
	:	Docket No. R-2025-3054394
Citizens' Electric Company of Lewisburg, PA	:	
	:	

SURREBUTTAL TESTIMONY OF KEVIN LUCAS ON BEHALF OF KELLY ROAD SOLAR, LLC, LANCASTER AVENUE SOLAR, LLC, AND TWILIGHT RENEWABLES, LLC

REVISED – Clean Version

Solar Projects' Statement No. 1-SR
August 28, 2025

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I. INTRODUCTION AND QUALIFICATIONS

Q1. PLEASE STATE FOR THE RECORD YOUR NAME, POSITION, AND BUSINESS ADDRESS.

A1. My name is Kevin Lucas. I am the Vice President of Policy Analysis at the Solar Energy Industries Association ("SEIA"). My business address is 1425 K St. NW #1000, Washington, DC 20005.

Q2. ARE YOU THE SAME KEVIN LUCAS THAT SUBMITTED DIRECT TESTIMONY IN THIS CASE?

A2. Yes, I am.

Q3. WHAT IS THE PURPOSE OF YOUR SURREBUTTAL TESTIMONY?

A3. The purpose of my rebuttal testimony is to address several arguments raised by Citizens' Electric Company of Lewisburg, PA ("Citizens'" or "the Company") and by the Pennsylvania Office of Consumer Advocate ("OCA").

Q4. DOES YOUR FAILURE TO ADDRESS A PARTICULAR WITNESS OR ISSUE IMPLY SUPPORT OF THAT WITNESS OR ISSUE?

A4. No, it does not.

Q5. PLEASE SUMMARIZE YOUR FINDINGS AND RECOMMENDATIONS

A5. The arguments advanced in Company's rebuttal testimony do little to bolster support for its Billing Demand proposal. It continues to claim that customer-generators should be billed based on demand they do not place on the system, and its rebuttal offer to "phase in" the results of its punitive proposal do not remedy the inherent flaws in the concept.

Citizens' admits that customer-generator's exported power may not cause incremental costs on its system, but it proposes to substantially increase distribution costs for these customers because of nebulous "new obligations" that they place on the system. However, these "obligations" are completely undefined, unsupported with analysis, and do not correspond to the physical use of the system by customer-generators. Despite this, the Company has doubled down on its flawed proposal, recalculating its rates based on the higher (and seemingly incorrect) inclusion of the new Billing Demand definition.

The results are even higher bills for customer-generators, despite no change in their usage of the system. I continue to recommend the Commission fully reject the proposed Billing Demand proposal.

In response to the Office of Consumer's Advocate ("OCA") discovery requests following the direct testimony filing, the Company expanded on its reasons why large customer-generators should be shifted off of the GSSR-1 tariff. The additional responses, along with a revised version of a prior analysis, provided the opportunity to scrutinize this proposal further. As with the Company's analysis on the impact of the Billing Demand proposal that I discussed in my direct testimony, I found the Company's analysis and reasoning wanting.

The Company has improperly discounted the non-trivial contribution that solar customer-generators make to reducing capacity costs on the Default Service Provider ("DSP") contract, in part due to a flawed analysis. After fixing the Company's errors, I find that not only do solar customer-generators reduce capacity costs, they reduce them in a manner that provides more value than the average cost to serve the DSP load. Put another way, the avoided cost value of solar generation on the DSP contract is higher than the Price to Compare ("PTC") cost of the DSP contract.

This finding renders moot the Company's claim that compensating annual excess energy from customer-generators at the PTC results in a cost shift to non-customer-generator customers. Instead, all customers taking service on the DSP contract benefit from the addition of solar generation on the Company's distribution grid. Additionally, a review of the Company's most recently approved DSP contract does not reveal any price increase due to a higher risk premium than the prior contract, despite concerns raised by OCA. Given this, I recommend the Commission allow customer-generators to take service on whatever DSP rate they prefer.

II. REBUTTAL OF CITIZENS' WITNESSES GORMAN AND JOHNSON

Q6. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A6. In this section of testimony, I discuss the rebuttal testimony of Company witnesses Howard S. Gorman[1] and Nathan Johnson.[2]

Q7. PLEASE SUMMARIZE YOUR FINDINGS.

A7. The Company introduces several new arguments in its rebuttal testimony. It argued that there is precedent under its demand ratchet and minimum billing provisions for billing customers not based on their actual usage, but some other measure. But these measures are fundamentally different in nature than the proposed Billing Demand metric, and raise their own concerns.

Citizens' claims that its proposal will reduce customer confusion. However, it is not distinguishing between the very few customers that would be required to switch to the GSSR-2 rate from the many more customer-generators that would see sizable distribution bill increases due to the same definitional change. Far form reducing customer confusion, the proposal will likely incite frustration among most customer-generators.

The Company introduces a new and inflammatory claim that the GSSR-1 tariff provides the perverse incentive for customer-generators to intentionally act to harm the rest of the ratebase by turning off their systems during peak hours in an effort to manipulate the capacity market to their benefit. This is an extraordinary argument, which not only lacks extraordinary support, but lacks any evidence or analysis whatsoever. The Company's argument is farcical in its face given a small customer-generator has no ability to effectively manipulate the price of the multi-billion dollar, multi-Gigawatt PJM capacity market. The Company's unfortunate testimony on this point can only be seen as an effort to unjustly discredit customer-generators and should be fully disregarded by the Commission.

[1] Citizens Statement No. 1R - Rebuttal Testimony and Exhibit of H. Gorman ("Gorman Rebuttal").
[2] Citizens' Statement No. 4R - Rebuttal Testimony and Exhibits of Nathan Johnson ("Johnson Rebuttal").

In its rebuttal testimony, the Company recalculated its rates based on the proposed Billing Demand definition. The new rates exacerbate the issues identified in my direct testimony, causing an even more punitive rate impact for customer-generators based on demand they do not place on the system and costs they do not impose. The result is an even more stark bill increase that appears to only benefit non-customer-generators.

Finally, I revisit the Company's updated analysis on the capacity contribution of solar generation and its ability to reduce costs on the DSP contract. I find that, contrary to the Company's claims, the avoided cost benefits of the solar generation profile handily exceed the cost of serving the DSP load profile. Quite simply, paying customer-generators for their excess power at the PTC undercompensates these customers for the excess generation. Given this was the main reason why the Company proposes to require larger customer-generators to take service on the GSSR-2 rate, I recommend the Commission reject this proposal and allow customer-generators to take service on whichever rate they prefer.

A. Ratemaking and Demand Ratchet

Q8. MR. GORMAN ARGUES THAT YOUR OBSERVATION THAT THE IMPACT TO THE COMPANY'S SYSTEM IS LIMITED TO THE SMALL SET OF ASSETS THAT SERVE A CUSTOMER-GENERATOR IS NOT RELEVANT FOR RATEMAKING PURPOSES.[3] HOW DO YOU RESPOND?

A8. Mr. Gorman does not disagree with the fact that any impact to the Company's system from customer-generator systems is limited to the assets serving that customer. This is readily observable when the Company experiences a limited outage on its distribution system from downed trees or equipment failures. Customers on distant parts of the Company's grid are not impacted and continue to receive service as they are not directly served by the assets experiencing the outage. Similarly, the physical impact on the

[3] Gorman Rebuttal at 18.

Company's system from a customer-generator is necessarily limited to the assets that serve that customer, and those impacts are attenuated as one moves further upstream from local line transformers to feeders to substations as the usage is blended in with dozens, hundreds, or thousands of other loads.

Instead, Mr. Gorman argues that rates are designed to "recover its costs for the entire distribution system, from all its customers", with an exception for customer-dedicated assets. This statement is accurate, but it not only missed the point of my testimony, it runs counter to the entire basis of the Company's Billing Demand proposal: that customer-generators are imposing differential obligations through their use of the system and must be treated differently than in the past and from other customers.

Q9. WHERE IN THE RATEMAKING PROCESS DOES THIS DECISION GET MADE?

A9. The decision to implement the Billing Demand proposal is "upstream" from cost allocation and rate design components of the ratemaking process. Put another way, the Billing Demand decision is a precursor to the Company's cost of service study and rate design steps. In fact, in the Company's rebuttal testimony, it recalculated its demand rates based on the new definition of Billing Demand and allowed for potential future revisions to cost allocation "which can be eventually based on the actual class data."[4] So while it is true that the mechanical steps of ratemaking is intended to recover costs of the entire system from customers, the specific results are very much a result of which assumptions and methodologies a utility proposes.

Q10. DO YOU CONTINUE TO BELIEVE THAT THE COMPANY MODIFIED ITS RATEMAKING PROCESS BASED ON A FAULTY PREMISE?

A10. Yes. The Company attempts to justify disparate treatment of these customers by billing them not based on their actual usage but their potential usage of the system because it claims they impose burdens on the system that are not captured through the traditional

[4] Gorman Rebuttal at 4.

measures of imported demand. It bases these arguments not on how it must plan and operate its entire system writ large, but instead on how it must serve these individual customer-generators: "From a distribution perspective, we have to plan the same for a customer that is exporting 400 kW to Citizens' as we do for a customer that is receiving 400 kW from Citizens'. In fact, our planning for the export of power to us is more complicated because of potential variability, voltage sags/surges and other issues."[5]

In other words, the Company's justification for the Billing Demand proposal is specific to the usage characteristics of customer-generators, and it is on the robustness of this argument that the proposal must be measured. The Company cannot sidestep this crucial step by claiming that the end result is based on all the costs on the entire grid; it must instead justify its Billing Demand proposal on the facts of said usage. And as I discussed in my direct testimony, I do not believe the Company has met this burden.

Q11. MR. JOHNSON AND MR. GORMAN POINT TO THE USE OF BILLING DEMAND RATCHETS AS A PRECEDENT FOR NOT CHARGING CUSTOMERS BASED ON THEIR ACTUAL USAGE.[6] HOW DO YOU RESPOND?

A11. Mr. Johnson observed that "from July 2024 to May 2025, only 52% of non-residential bills charged for the actual metered demand during the same period" due to the 50% demand ratchet. Mr. Gorman had a slightly different figure, saying that only 49% of customers were billed based on their actual demand.[7] Regardless of whether it is 52% or 49% of customer bills that are caught by the demand ratchet, this is a troubling result. Given that nearly all of the distribution assets that serve customers are shared assets that are planned, sized, and operated to meet the diversified demand of the customers on the assets, it appears the Company is charging customers based on what are likely anomalous

[5] Citizens' Statement No. 4 at 17.
[6] Johnson Rebuttal at 39.
[7] Gorman Rebuttal at 15. Mr. Gorman states "Approximately 51% of all customer bills issued for GLP-1 and GLP-3 during the year are billed using the alternative measure (i.e., 50% of the highest monthly Billing Demand during the prior 11 months) rather than the metered monthly demand usage."

non-coincident peak ("NCP") demand that may have nothing to do with the cost causation of those demands.

The Company's statement means that roughly half of customer bills were for monthly peak demands that were less than half of the single maximum peak demand in the prior year or less than the 5 kW minimum demand on the GLP-1 tariff. For example, this could mean that a customer who had a peak demand of 100 kW in one month had demands of less than 50 kW in all other months would still be charged for 50 kW of usage for up to 11 months even if the 100 kW was an unusual outlier. Unless the Company has definitive evidence that even half of this peak demand of 100 kW was reflective of the cost-causing demand that they actually placed on the system, then it may be charging customers inappropriately based on a demand ratchet that is not tied to costs. I recommend the Commission investigate this issue further and request that the Company demonstrate that its use of the demand ratchet results in appropriate bills for its customers.

Q12. IS THIS DEMAND RATCHET ISSUE EXACERBATED WHEN COMBINED WITH THE PROPOSED BILLING DEMAND DEFINITION?

A12. Yes. There is a key distinction between being billed based on a demand ratchet and being billed based on the Company's proposed Billing Demand methodology. As problematic as the demand ratchet may be, it at least is based on some fraction of actual demand that a customer has placed on the grid in the prior 11 months. By contrast, the Billing Demand methodology is based on a hypothetical demand value that *may never be placed* on the Company's grid and can be substantially larger than any actual measure of demand the customer-generator draws from or places onto the Company's system.

Q13. DO YOU HAVE A ROUGH SENSE OF HOW SIZABLE THIS DIFFERENCE COULD BE?

A13. Yes. In my direct testimony, I corrected the Company's analysis related to how its Billing Demand proposal would impact a hypothetical customer.[8] As part of the modifications of the workpaper, I enabled functionality to quickly modify the customer peak demand and solar system and calculate the resulting power flows and customer Billing Demands under the current and proposed definition. I simulated potential combinations of customer peak demand and PV system size, with the results shown below in Table 1.

Billing Demand / Inflow Ratio				
	Customer Peak Demand			
PV System Size	**25**	**50**	**75**	**100**
25	1.27	1.00	1.00	1.00
50	2.55	1.27	1.00	1.00
75	3.83	1.91	1.27	1.00
100	5.11	2.55	1.69	1.27
125	6.40	3.19	2.12	1.59
150	7.68	3.83	2.55	1.91
175	8.96	4.47	2.98	2.23
200	10.25	5.11	3.41	2.55
225	11.53	5.75	3.83	2.87
250	12.82	6.40	4.26	3.19

Table 1 – Biling Demand / Inflow Demand Ratio

Q14. HOW DO YOU INTERPRET THESE RESULTS?

A14. The values in the table show the ratio of the average monthly customer peak demand under proposed Billing Demand definition and the current peak demand definition. The columns represent customers with different size peak demands (ranging from 25 kW to 100 kW in 25 kW increments), while the rows represent different size PV systems (ranging from 25 kW to 250 kW in 25 kW increments). The intersection of the row and column contains the result of dividing the average Billing Demand value by the average peak demand value. For instance, a customer with a 50 kW peak demand and a 100 kW PV system would see an average monthly Billing Demand that was 2.55 times larger than

[8] Lucas Direct at 9.

the current peak demand measurement, even if they never exported 100 kW to the Company's grid.

Q15. WHAT PERCENTAGE OF THAT CUSTOMER'S ANNUAL USAGE WOULD BE MET BY THAT SIZE SOLAR SYSTEM?

A15. Using the Company's example customer scaled to 50 kW peak demand, a 100 kW solar system would only cover about 51% of their annual load. Despite this relatively modest system size, the Company's proposed Billing Demand definition would result in distribution demand charges that are more than 2.5 times higher than under the current definition. For a customer wishing to offset their entire annual load, the new Billing Demand would be about 5 times higher than the current definition. This stands in stark contrast to the Company's demand ratchets, which are only triggered when peak demand falls below 50% of what a customer has already attained in the prior 11 months.

Q16. IS THERE ANOTHER PROBLEMATIC INTERACTION BETWEEN THE BILLING DEMAND DEFINITION AND THE DEMAND RATCHET?

A16. Yes. Because the demand ratchet would set the minimum demand based on the new Billing Demand definition – which could be based entirely on the gross generator rating ("GGR") of the PV system – a customer who meets more than roughly 20% of their annual usage could never reduce their ratcheted demand without changing the PV system hardware.[9] Using the Company's example customer's load profile, if a customer with a 100 kW peak demand installed an 80 kW PV system, they would offset roughly 20% of their annual usage and see their peak inflow demand fall from 100 kW to 80 kW. But because their Billing Demand could never fall below 80 kW due to the GGR, even if they took actions to further reduce their demand below 80 kW, they would get no relief on their demand charges because the GGR would set the billing demand floor in every month.

[9] Using the Company's example load profile, a customer with a PV system equal to 80% of their peak demand (e.g., a 100 kW customer with an 80 kW PV system) would see their demand switch from their actual usage of the grid to the GGR.

B. Customer Confusion, Alternative Definition of Billing Demand, and Billing Demand Phase In

Q17. THE COMPANY CONTINUES TO ASSERT THAT ITS BILLING DEMAND DEFINITION WILL "REDUCE CUSTOMER CONFUSION."[10] WHAT IS YOUR RESPONSE TO THAT?

A17. I disagree, and in fact, it is difficult to see how customer confusion would not increase under the proposal. The Company proposes to use the Billing Demand definition for two purposes: 1) assigning a customer taking default service to either GSSR-1 or GSSR-2, and 2) billing customers for a portion of their distribution costs. The former decision point would only affect customers with DG system sizes over 400 kW_{AC}, which is a small subset of customer-generators. Of the 87 customer-generators (15 of which are non-residential systems) that are currently taking service with the Company, only one is larger than 400 kW_{AC}.[11] Of the additional 12 projects that are listed as "Indicated" or "Applied / In Progress" (5 of which are non-residential), only two exceed 400 kW_{AC}.[12] In other words, even if all of the projects that exist or that the Company is aware of were all built, only three out of 99 would be impacted by the Company's proposal to assign default supply rates based on the 400 kW_{AC} Billing Demand threshold. This change would result in a sizable, negative impact for these individual customers, but it would not result in widespread customer confusion across the entire non-residential customer base.

On the other hand, all of the non-residential customer-generators would be impacted by a sizable change in their bills due to the use of the proposed Billing Demand definition on their distribution bills. Because all but one of these existing customers have system sizes below 400 kW_{AC}, they would not be impacted by the assignment of supply rates, but would nonetheless see sizable distribution bill increases. Why the Company believes that this would result in "reduced customer confusion" and not confused and frustrated customers who just received a huge bill increase is unclear.

[10] Johnson Rebuttal at 25.
[11] Exh. KL-7, SP-I-2 Attachment A.
[12] *Id.*

Q18. IS THE COMPANY OPEN TO USING AN ALTERNATIVE DEFINITION OF BILLING DEMAND?

A18. It appears so, but only if ordered by the Commission.[13] The Company acknowledges that "[t]here are other possibilities that could be used, such as the 15 minutes of maximum bi-directional demand during the billing cycle."[14] But it notes that its current meters are not configured for measuring bi-directional demand and would require reprogramming. It also raises a concern that "using the bi-directional demand could result in an account moving between the GSSR-1 and GSSR-2 net-metering credit process on an annual basis."[15]

Q19. DO YOU SEE EITHER OF THESE AS MAJOR ISSUES?

A19. No, although I continue to believe using bi-directional demand for the purposes of billing customers for their usage to be inappropriate for all the reasons discussed in my direct testimony. That said, if the Commission were to approve that definition, I do not believe these two issues are major impediments to using that definition.

First, the number of meters that would need to be reprogrammed is small as the Company currently only has 15 non-residential customer-generators on its system. Any new customer-generator could have a meter preconfigured for bi-directional measurement before installation, obviating any additional work. Second, while the Company did not provide the peak inflow demand of its customer-generators, it is reasonable to assume that the PV system size will be similar or larger in size than the customer's peak demand.[16] Given only one existing non-residential customer-generator exceeds the 400 kW_{AC} threshold (and, at 1.77 MW, by a sizable amount), the only way for other customer-generators to switch between GSSR-1 and GSSR-2 on an annual basis due to their actual peak bi-directional demand would be for their imported power to fluctuate above and below 400 kW.

[13] Johnson Rebuttal at 25.
[14] *Id.*
[15] Johnson Rebuttal at 26.
[16] As discussed above, a customer seeking to offset a reasonable portion of their annual usage will need to install a PV system that exceeds its peak demand.

Q20. DO YOU BELIEVE THIS WOULD HAPPEN OFTEN?

A20. No. Of the 15 non-residential customer-generators in service, 11 have PV systems under 200 kW_{AC}. For these systems to flip the net imported power from above 400 kW to below 400 kW would require a customer to have a sizable daytime load (e.g., 500 kW), which means the systems are offsetting very little of the customer's annual generation. For the 3 systems between 200 kW_{AC} and 400 kW_{AC}, the daytime load of the customer would need to be even larger.

Given the average GLP-1 customer has a billing demand of 12 kW[17] and that nearly all of the existing non-residential customer-generators take service on this tariff, the odds that all of the customer-generators on this tariff are extreme outliers with several hundred kW of demand is low. More likely, these customers have peak demands that are equal to or lower than their PV system sizes (which are already below the 400 kW_{AC} threshold), meaning that they are highly unlikely to switch between the GSSR-1 and GSSR-2 tariff on an annual basis based on actual power flows.

Q21. THE COMPANY PROPOSES TO PHASE IN THE BILLING DEMAND DEFINITION OVER THREE YEARS FOR DISTRIBUTION RATES.[18] WHAT IS YOUR RESPONSE TO THIS?

A21. This is a solution in search of a problem. First, the Company does not propose to phase in the definition to the supply rate, which would be implemented immediately in January 2026. Second, phasing in the Billing Demand definition over three years does not remedy its flaws; it merely tries to cushion the rate shock that would result from the unsupported proposal. The customers that would be the most impacted by this change – those with large systems relative to their on-site load – the economic life of a solar system is measured in decades, not in years. Phasing in a substantial increase in distribution costs over three years will do little to mitigate the lifetime financial impact on the system.

[17] Schedule B6-3 shows Schedule GLP-1 with 13,644 annual bills and 163,587 kW of annual demand. Dividing the latter by the former results in roughly 12 kW of monthly demand.
[18] Johnson Rebuttal at 22.

C. GSSR-1 and GSSR-2 Price Signals and Incentives

Q22. THE COMPANY SUGGESTS THAT CUSTOMER-GENERATORS TAKING SERVICE ON THE GSSR-2 TARIFF HAVE A GREATER INCENTIVE TO MAXIMIZE EXPORTS DURING PEAK HOURS.[19] WHAT IS YOUR RESPONSE TO THIS?

A22. I disagree with the Company's hypothesis. Mr. Johnson argues that a customer-generator placed on the GSSR-2 tariff will have an incentive to export to the grid "during higher-priced hours."[20] He continues:

> Although a solar generator may be relatively inelastic in producing power in response to hourly prices, many qualifying net-metered generation sources are able to respond directly to price signals. In addition, even the customer-generator with a solar array may be able to reduce the host load consumption to increase its exports during these hours.[21]

Q23. WHAT IS WRONG WITH THIS STATEMENT?

A23. As a primary matter, there is no way for a customer-generator to respond to the price signal provided by the GSSR-2 tariff. That tariff charges (or compensates) generation at the "actual real-time PJM West Hub Locational Marginal Price ('LMP') for each hour of the billing month"[22] The real-time LMP price is recalculated every five minutes throughout the day, and the "actual" value for any given hour cannot be calculated until the hour has already passed since it is necessarily the load-weighted average of the 12 five-minute periods of that hour. In other words, by the time a generator could even know what the real-time hourly rate at which they will be charged (or compensated), their usage (or generation) will have already occurred.

Q24. COULD A CUSTOMER-GENERATOR MONITOR THE REAL-TIME 5-MINUTE LMP INTERVALS AND MODIFY THEIR BEHAVIOR IN RESPONSE TO THESE PRICE SIGNALS?

[19] Johnson Rebuttal at 27.
[20] Johnson Rebuttal at 28.
[21] *Id.*
[22] GSSR-2 Rider

A24. No. PJM itself does not display the price of a 5-minute interval until most of the way through the interval.[23] Further, the idea that a business should be expected to moderate its load in response to price signals that could change by hundreds of dollars per MWh in minutes overstates the likely flexibility of the loads. It is one thing to reschedule a production line 24 hours in advance or even to make planned load adjustments several hours in advance based on expected prices, but actively managing a business enterprise based on minute-by-minute price fluctuations in the PJM wholesale market is a bar too high for nearly all businesses.

More problematically, the PJM real-time LMP frequently experiences unpredictable "needle peaks" where the price may jump by considerable amounts in one 5-minute interval only to fall just as rapidly as the generators on the grid are re-dispatched. For example, on August 25th, real-time prices were low in early morning hours and largely consistent with the day-ahead prices. At 8:10 AM, the Western Hub Real-Time LMP was $22.82/MWh. At 8:15 AM, it increased to $79.90/MWh. At 8:20 AM, it fell back to $25.65/MWh and stayed at or near that level for most of the rest of the morning. These needle peaks are not uncommon, as shown in Figure 1 below.[24] Moreover, they are not predictable since they are necessarily the result of very short-term imbalances in supply and demand resulting from issues such as unplanned generator or transmission line outages or sudden, unanticipated spikes in demand. The suggestion that customer-generators should or would monitor and respond to these "price signals" on a continuous basis is not reasonable.

[23] https://dataviewer.pjm.com/dataviewer/pages/public/lmp.jsf. The prices on the publicly accessible pages updated roughly four minutes into a given five-minute period. For example, the price for the period from 2:40 PM to 2:45 PM was updated on the PJM website at 2:44.

[24] Data accessed from https://dataviewer.pjm.com/dataviewer/pages/public/lmp.jsf at 3 PM on August 25, 2025.

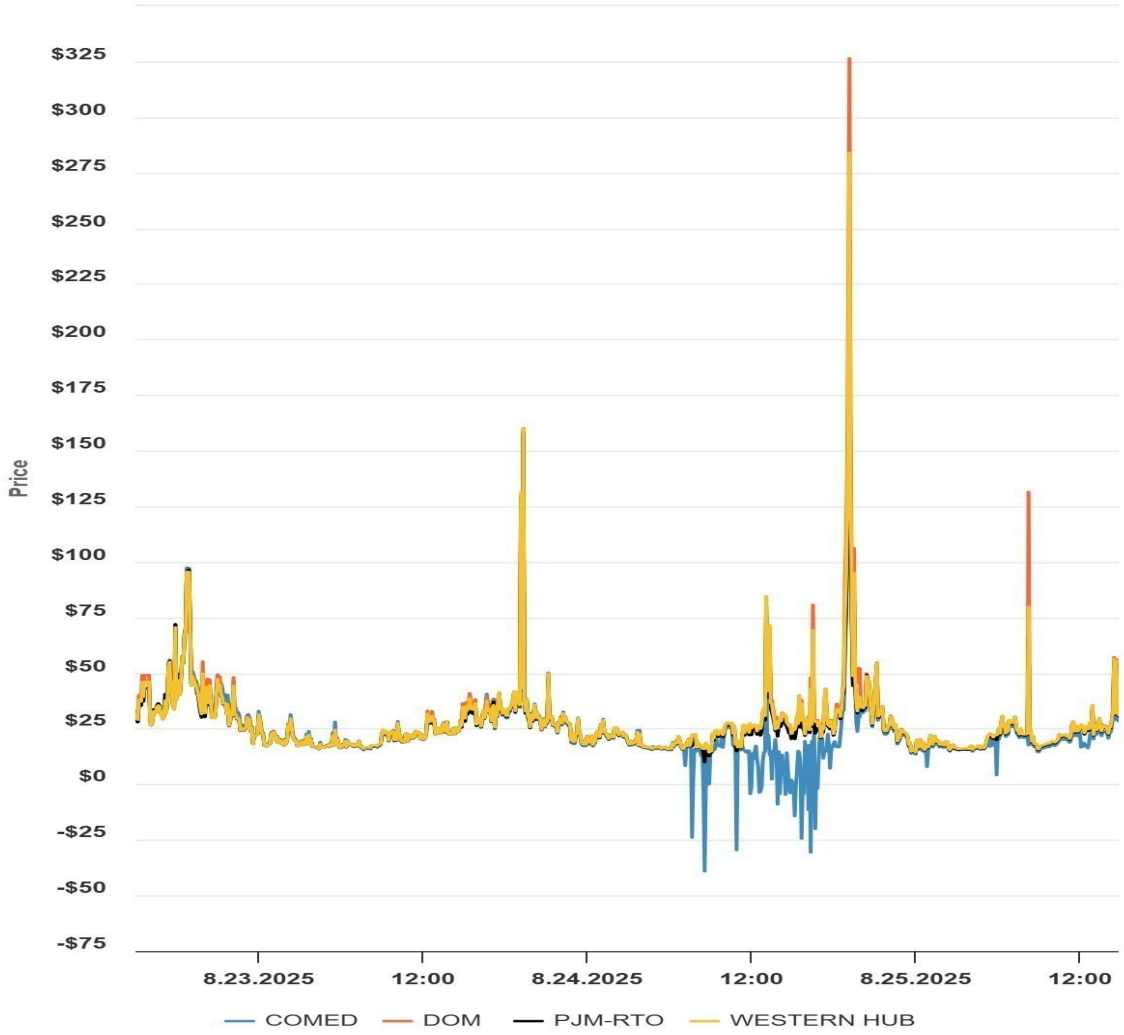

Figure 1 - PJM Real Time Prices August 22, 2025 to August 25, 2025

Q25. DOES THE COMPANY BELIEVE THESE PRICE SIGNALS AND INCENTIVES ALSO EXIST ON THE GSSR-1 RATE?

A25. No. In fact, the Company goes further and suggests that customer-generators have an incentive to withhold generation during peak hours to intentionally increase GSSR-1 rates.

> In fact, the GSSR-1 rate provides an economic disincentive for exporting during high-demand hours. Net exporting customer-generators are paid at the end of the energy-year at the PTC, which includes transmission and capacity costs determined by the Company's contribution to annual PJM peak hours. Exporting during peak hours reduces the Company's costs, thus reducing the value of export credits. Net-metered generation is non-dispatchable and, as Mr. Nolt states in his

> testimony, is able to "go offline immediately" so a customer-generator could reduce or eliminate output during peak hours to maximize the value of future export credits. In short, rather than incentivizing customer-generators to export during peak hours for benefit of all ratepayers in the class, the GSSR-1 rate structure, coupled with net metering code requirements, provide a financial incentive for customer-generators to deny exports during peak hours at the cost of non-exporting ratepayers.[25]

Q26. WHAT IS YOUR PERSPECTIVE ON THIS STATEMENT?

A26. This is a rather staggering accusation. The Company asserts – with no evidence or analysis whatsoever – that customer-generators would engage in market manipulation by intentionally reducing the output of their solar facilities in order to increase the peak demand of customers being served on the GSSR-1 tariff in hopes of inflating the future costs of that rider. It further presupposes that this increased peak demand will necessarily translate into increased costs that must be recovered from GSSR-1 customers, eventually increasing the credit rate at which exported energy is compensated.

Putting aside the unfounded and incredibly cynical basis for the statement, there are three problems with the Company's assertion. First, no customer knows when the five coincident peak hours that will be used in PJM's calculation of generation and transmission capacity cost allocation will occur. These are only announced months after the fact and are by definition retrospective. For a customer-generator to be confident of impacting one of these five hours, they would have to reduce their generation output on many hot afternoons as one simply cannot be determined with any precision when a combination of weather and customer load will trigger one of these system-wide peak hours.

Second, this repeated reduction in generation will have a much larger impact on a generator's compensation than any hypothetical price increase triggered by the intentional withholding of exported power could have. A customer-generator would be taking a sizable risk that forgoing guaranteed revenue by not generating on a given day

[25] Johnson Rebuttal at 28-29.

will result in future price increases that more than offset the lost revenue, particularly given the insignificance of a single distribution-connected DG system on the multi-Gigawatt, multi-billion dollar PJM capacity market.

Third, the DSP contract that the Company has with its wholesale supplier passes through PJM generation capacity and transmission costs directly based on the actual costs apportioned to the Company. The Company then divides these dollars by the kWh sold on the GSSR-1 tariff to determine the GSSR-1 $/kWh rate component for the recovery of generation and transmission costs. If a customer-generator reduced their output, it would result in increased net sales at the Company's PJM settlement point, which means the capacity costs would be divided by a larger quantity of sales. This would tend to reduce, not increase, the $/kWh rate that a customer-generator would be credited for excess generation.

Q27. PUTTING ASIDE THESE ISSUES, IS THERE EVEN A HYPOTHETICAL POSSIBILITY THAT A CUSTOMER-GENERATOR WOULD BENEFIT FROM THE MARKET MANIPULATION SUGGESTED BY THE COMPANY?

A27. No. Suppose a customer on the GSSR-1 tariff had a 100 kW_{AC} PV system that produced 147 MWh per year.[26] For a BTM customer-generator, much of this production will be used on-site and will not result in exported power. But to illustrate a worst-case scenario, suppose that all power was exported and compensated at the GSSR-1 rate.

The GSSR-1 rate used in the Company's workpapers included was $110.77/MWh, $42.27/MWh of which was for generation and transmission capacity.[27] At this rate, the customer-generator would receive $16,284 for excess generation at the end of the year. Suppose that this customer could magically determine exactly which five hours would be used in the PJM cost allocation process and decided to "turn off" their generation during only those five hours. Given that PJM's peak hours tend to occur

[26] This is the expected generation using the Company's PVWatts assumptions.
[27] Company workpaper SP-II-5 Attachment A.

between 4 and 6 PM EPT, the 100 kW generator will not be outputting 100 kW, but something lower.[28] The exact value will depend on the weather, but to continue the "worst case scenario", one can assume they may be outputting an average of 56 kW during these hours.[29] If the customer-generator deactivated the generation for these five hours, it would forgo roughly $31 in compensation.[30] In order for the customer-generator to come out ahead as a result of this behavior, the price of the transmission and capacity components of the GSSR-1 rate would have to increase by at least 0.5% as a direct result of the individual customer-generator's actions.[31]

In reality, a customer-generator would not have the magical ability to only deactivate their system during the 5 CP hours as these hours are not known in advance. Instead, a customer-generator seeking to manipulate the market to its favor would have to turn off their system during many summer afternoons between 4 PM and 6 PM with the hopes that one of those days would end up being a 5 CP hour. If they instead picked 20 days during which to target their peak load increase, the forgone revenue would increase by roughly 5 times, which would in turn require the capacity price impact from the customer-generator's actions to be in the 2-3% range to recoup the losses.

Q28. IS THERE ANY EVIDENCE WHATSOEVER OF A COORDINATED EFFORT AMONG ANY, MUCH LESS ALL, OF THE CUSTOMER-GENERATORS TO INTENTIONALLY DEACTIVATE THEIR SYSTEMS DURING PEAK HOURS TO MANIPULATE THE MARKET PRICE OF CAPACITY AND TRANSMISSION SERVICES?

[28] 18 of the past 20 5CP hours occurred either between 4 PM and 5 PM EPT or between 5 PM and 6 PM EPT. https://www.pjm.com/-/media/DotCom/planning/res-adeq/load-forecast/summer-2024-peaks-and-5cps.pdf

[29] The average of the five highest generation hours between 4 PM and 6 PM EPT from June to September in the Company's workpapers for a 100 kW_{AC} system averaged 56.5 kW. This represents the largest increase to peak demand that the customer-generator might expect to make on the 5CP days by shutting down its PV system.

[30] 56 kW * 5 hours * $110.77/MWh = $31.32 in lost revenue.

[31] Returning to the original revenue would require a total PTC of $110.98/MWh, which is $0.21/MWh higher than the original price. This would require a 0.51% increase in the generation and transmission capacity prices.

A28. Of course not. But even if there was, the ability for an individual customer-generator's behavior today to impact future capacity prices is swamped by so many other factors as to be rendered moot.

Q29. HOW MUCH CUSTOMER-GENERATOR SOLAR CAPACITY IS CURRENTLY OPERATING ON THE COMPANY'S GRID?

A29. The Company indicated it has about 4.1 MW of customer-generators in service on its system across all customer sizes and types.[32] Much of this is serving behind-the-meter loads, meaning only a fraction of this capacity would benefit from the hypothetical market manipulation suggested by the Company.

Q30. HOW MUCH LOAD WAS PRESENT DURING THE 2024 5 CP HOURS IN THE PPL PJM ZONE, WHICH SETS THE CAPACITY PRICE FOR THE COMPANY?

A30. The average of the 2024 5CP hours in PPL's PJM zone was 6,928.2 MW.[33]

Q31. WHAT WAS THE RECENT AMOUNT OF OFFERED AND CLEARED CAPACITY IN THE MOST RECENT PJM CAPACITY AUCTION IN THE PPL ZONE?

A31. The PJM PPL zone had 8,424.6 MW of capacity offered and cleared 8,377.4 MW of capacity.[34]

Q32. PUTTING THESE FIGURES TOGETHER, WHAT WOULD HAVE TO HAPPEN FOR A CUSTOMER-GENERATOR'S DECISION TO DEACTIVATE THEIR SYSTEM DURING PEAK HOURS TO IMPACT CAPACITY PRICES TO A SUFFICIENT DEGREE TO MAKE IT WORTH THEIR WHILE?

A32. First, a customer-generator would have to be served on the GSSR-1 tariff and have annual excess energy. This already eliminates any customer with a system that does not produce more energy over the course of the year than their consumption. Then, the customer will have to decide to attempt to manipulate the PJM capacity market by intentionally shutting their system down for several hours during hot summer afternoons.

[32] Exh. KL-7, Company workpaper SP-I-2 Attachment A.
[33] https://www.pjm.com/-/media/DotCom/planning/res-adeq/load-forecast/summer-2024-peaks-and-5cps.pdf
[34] https://www.pjm.com/-/media/DotCom/markets-ops/rpm/rpm-auction-info/2026-2027/2026-2027-bra-report.pdf

Depending on the system size and configuration, this may require the repeated manual flipping of cutoff switches and accepting any additional wear and tear on components that results.

Following this, the customer will have to sit around and wait to see if the day they selected to shut off their system ends up being one of the 5 CP hours on which PJM capacity cost allocations are based. If they missed by even an hour, they would have forgone guaranteed revenue based on speculation. But even if they were right, they would then have to wait several years for the increase in load attributable to their action to be captured via PJM's load forecast methodology and subsequently increase the load obligation of the PPL zone.[35] Next, generation and other capacity resource owners would have to bid in a manner where the marginal increase in PPL zonal load from the foregone solar generation triggers a price increase in the capacity market that exceeds the lost revenue from shutting down their system. Finally, three to four years hence, the customer-generator would have to wait for the end of the year to receive any added compensation for their annual excess generation that their actions has netted them.

Q33. IS THIS IN ANY WAY A REALISTIC SCENARIO?

A33. No; it is instead an absurd one. Putting aside the notion that the Company's small customer-generators will be flipping disconnect switches on hot summer afternoons in an attempt to manipulate the multi-billion-dollar PJM capacity market, the actions of any individual customer-generator would simply be lost among the many thousands of MW of load and generation that set PJM capacity prices. Even if there was a grand conspiracy and all 4.1 MW of customer-generators (including those that do not have any excess annual generation and thus would be completely unmotivated to lose money) turned off their systems during hot summer hours, this would only represent 0.05% of the cleared capacity in the PPL zone and has essentially zero chance of affecting the clearing price.

[35] PJM capacity prices are typically set three years in advance, although the capacity auction schedule has been compressed in recent years.

Q34. WHAT DO YOU RECOMMEND WITH RESPECT TO THIS "CONCERN" RAISED BY THE COMPANY?

A34. I recommend the Commission completely and wholeheartedly disregard it. It is a specious argument that has no basis in rational action by customer-generators and should be summarily dismissed.

D. The Billing Demand Proposal Discriminates Against Customer-Generators in Favor of Non-Customer Generators

Q35. WHAT CHANGES DID THE COMPANY MAKE TO ITS RATE DESIGN IN ITS REBUTTAL TESTIMONY?

A35. The Company modified the billing determinants that it used to calculate the demand charge in the GLP-1 and GLP-3 tariffs to confirm with its proposed Billing Demand definition.[36] In its original application, the Company used the actual and/or ratcheted demand from the customer to calculate the demand rates. When these were updated based on the proposed definition, the total demand billing determinants on the GLP-1 tariff increased by roughly 25%, going from 163,587 kW to 203,588 kW. The GPL-3 tariff had a much smaller increase given the fewer number of customer-generators and relatively larger customer loads on this tariff, increasing from 131,543 kW to 133,103 kW. The increase in billing determinants has an inverse effect on demand rates as they are still designed to recover the same revenue. The GLP-1 rates fell roughly 20% from $4.44/kW to $3.79/kW, while the GLP-3 rates fell modestly from $6.78/kW to $6.71/kW.

Q36. WHAT IS THE PRACTICAL EFFECT OF THIS CHANGE?

A36. The practical effect is that the 13 customer-generators on the GLP-1 tariff will see a massive increase in distribution costs, while the 1,124 non-customer-generators on the GLP-1 tariff will see a non-trivial distribution bill reduction.[37]

Q37. IS IT POSSIBLE TO CALCULATE THE MAGNITUDE OF THIS CHANGE?

[36] Gorman Rebuttal at 4. All figures in this paragraph are from Table HGS-2.
[37] Table HGS-2 indicates 13,644 annual bills, which is 1,137 customers. Workpaper SP-I-2 Attachment A shows 13 current customer-generators take service on the GLP-1 tariff, with a combined rated capacity of 2,967 kW.

A37. It is possible to get a rough estimate, although the Company's figures and discovery responses conflict with each other. Specifically, the increase in the GLP-1 billing determinants due to the inclusion of the GGR (3,333 kW per month) is larger than the sum of the GGR reported for active customer-generators on the GLP-1 tariff (2,967 kW per month). Given many of these customers are BTM generators, their demand under the current definition should not be zero, widening the disparity in the Company's figures.

The Company does not indicate that any of the "in progress" solar projects will take service on the GLP-1 tariff, nor does it include any new GLP-1 customers in its projected test year.[38] Further, after reviewing a confidential discovery response just before filing this testimony that included details about individual GLP-1 net metered customers, the 40,001 kW annual increase used in the bill determinant recalculation is substantially larger than the sum of the incremental Billing Demand in that workpaper.[39] I recommend the Commission investigate this matter further if it accepts the Company's Billing Demand definition to ensure that rates are being calculated correctly.

In my analysis using publicly available data, I attempted to de-skew the average cost impact due to the one very large (1.77 MW) customer-generator currently taking service on GLP-1 by separately analyzing this customer.[40] Using Excel, I set up a set of equations to calculate the average demand of the 1,124 non-customer generators and the 12 remaining customers-generators under the old and new definitions, setting the resulting total demand equal to the values in Table HGS-2. I then used Excel's Solver to solve the equations.[41] The results are found in Table 2 below.

[38] Exh. KL-7. In SP-I-2 Attachment A, all four projects listed as "Applied / In Progress" are listed on rate GLP-3. In the Company's COSS Study (Schedule B2-1), there are no additional customers forecasted for 2025 or 2026.
[39] Citizens' HIGHLY CONFIDENTIAL SP-II-11 Attachment A. I reviewed the workpaper too late to modify the analysis below. That said, the analysis presented here does not utilize confidential data and can thus be publicly filed and is largely consistent with the customer-specific results in the confidential attachment.
[40] Breaking this customer out made it impossible to solve the equations perfectly, although the resulting answer is within roughly 2.5% of the demand totals listed in the Company's rebuttal testimony.
[41] The equations have multiple results depending on the assumed average demand of non-customer-generators and customer-generators. Absent any additional information, I seeded the Solver algorithm with the assumption that the

	Direct Definition			
	Non Cust-Gen	1.77 MW Cust-Gen	Other Cust-Gens	Total
Customers	1,124	1	12	1,137
Avg Demand	12	380	12	
Avg kWh	1,994	0	1,994	
Customer Charge	$21.00	$21.00	$21.00	
Demand Rate	$4.44	$4.44	$4.44	
Energy Rate	$0.01143	$0.01143	$0.01143	
Customer Charge	$21.00	$21.00	$21.00	$23,877
Demand Charge	$53.23	$1,688.20	$53.23	$62,162
Energy Charge	$22.79	$0.00	$22.79	$25,894
Total Monthly	$97.03	$1,709.20	$97.03	$111,933
Total Annual	$1,164.33	$20,510.44	$1,164.33	$1,343,192
	Rebuttal Definition			
	Non Cust-Gen	1.77 MW Cust-Gen	Other Cust-Gens	Total
Customers	1,124	1	12	1,137
Avg Demand	12	1,766	113	
Avg kWh	1,994	0	1,994	
Customer Charge	$21.00	$21.00	$21.00	
Demand Rate	$3.79	$3.79	$3.79	
Energy Rate	$0.00976	$0.00976	$0.00976	
Customer Charge	$21.00	$21.00	$21.00	$23,877
Demand Charge	$45.44	$6,693.14	$427.97	$62,904
Energy Charge	$19.46	$0.00	$19.46	$22,110
Total Monthly	$85.90	$6,714.14	$468.43	$108,892
Total Annual	$1,030.85	$80,569.68	$5,621.18	$1,306,699

Table 2 – Billing Demand Definition Impact on Rates and Bills

Q38. HOW DO YOU INTERPRET THESE RESULTS?

A38. Assuming the Company's discovery responses and calculations are correct (although they do conflict with each other), mathematically the only way for the total demand billing determinants to increase by the 40,001 kW per year from 13 customers is for each customer to see a sizable increase in their assigned billing demand. In all likelihood, the one large 1.77 MW customer-generator represents a sizable portion of the increase, which I estimated at just over 40% of the total.[42] Even when I separately account for this, the

two groups of customers had the same average demand under the current definition. Even if customer-generators have larger-than-average demands, the total bill impact of this change remains similar.

[42] I estimated the average peak demand of this customer assuming a 50% load factor and using the 2022 sales from Workpaper SP-1-14 of 1.66 million kWh, resulting in an average peak demand of 380 kW. This customer's 2024 sales were reduced to 0 kW, suggesting that their solar system is fully offsetting their annual usage.

remaining customer-generators see an average billing demand increase of roughly 101 kW per month.

The impact on the customer-generators is sizable. The single large customer-generator would see its bill increase by more than $60,000 per year, a truly punitive amount and equal to a nearly 300% increase in its distribution bill. The remaining customer-generators would on average see bill increases of about $4,500 per year, representing a nearly 400% increase. Meanwhile, the non-customer generators would on average receive an 11% reduction in their demand charges, despite no change in behavior or usage of the system.

Q39. WHAT POSSIBLE JUSTIFICATION FOR THIS RESULT DOES THE COMPANY PROVIDE?

A39. Despite admitting that customer-generator exports do not always cause an increase in costs, and even if they did, that it has not done the requisite studies to determine those costs, the Company essentially claims that it has been billing customers wrong for as long as it has had customer-generators:

> Q. If the new "obligations" above do not result in incremental costs to serve its customers, does the Company believe it is appropriate to charge the customer-generator more after installing the on-stie generation? Please explain in full.
>
> A. Yes, just as obligations from new or increased load that increase peak consumed demand will result in increased charges to customers—regardless of whether specific, measurable incremental cost increases can be directly correlated to the new load—the Company proposes to charge exported 'demand' in a similar manner. The Company cannot reasonably calculate the exact incremental costs incurred by each individual customer on an ongoing basis, which is one of the reasons why tariffed rates are used. Billing demand and usage provide the best reasonable representation of a customer's relative utilization of the distribution system and, as such, are appropriate quantities on which to base customer bills.[43]

In short, the Company claims that customer-generators place new "obligations" on the system, and that even if these obligations do not increase the cost of the system, it is nonetheless appropriate for customer-generators to pay more for their use of the

[43] Exhibit KL-8, SP-VI-5.c.

system. In the example above, "serving" these new "obligations" results in a typical customer-generator seeing their costs increase by thousands of dollars per year.

Q40. HAS THE COMPANY PERFORMED ANY ANALYSES TO SUPPORT THIS DRAMATIC RESULT?

A40. No. The Company admits that adding customer-generators to its systems "do[es] not always result in incremental cost increases to operate and maintain the system."[44] It admits that customer-generators must pay for required studies and systems upgrades to safely interconnect with the Company's system.[45] It admits that adding distributed generation to its system will never increase feeder peak demand.[46] It admits that it has not performed a cost of service study comparing the cost responsibility using actual metered energy flows or its GGR Billing Demand methodology.[47] It admits that it does not perform marginal cost of service studies for its distribution system specifically related to the marginal cost of exports from distributed generation.[48] Finally, it admits that it is not aware of any other unbundled distribution utility that uses its proposed Billing Demand methodology.[49] In short, it has done none of the legwork required to demonstrate its proposal is just and reasonable.

Q41. DID THE COMPANY IDENTIFY WITH ANY SPECIFICITY WHAT THESE NEW "OBLIGATIONS" ARE?

A41. It specifically noted that customer-generators place new obligations on the system "by exporting more energy than it previously imported, and then expecting the return of the 'banked' excess supply on-demand."[50] It continued, "Finally, the Company does not argue that generation, by nature, creates additional costs compared to consumption of a

[44] Exhibit KL-9, SP-VI-5.b.
[45] Exhibit KL-10, SP-I-19, Exhibit KL-11, SP-I-20.
[46] Exhibit KL-12, SP-V-2.a.iii.
[47] Exhibit KL-13, SP-IV-6.
[48] Exhibit KL-14, SP-IV-23.
[49] Exhibit KL-15, SP-V-3.
[50] Johnson Rebuttal at 23.

similar magnitude. Rather, we seek to treat all utilization of the distribution system equally, regardless of the direction in which power flows"[51]

Q42. WHAT IS THE "RETURN OF THE 'BANKED' EXCESS SUPPLY ON-DEMAND" DESCRIBING?

A42. Physically, it is describing nothing other than the Company providing power to the customer-generator. The power grid does not physically separate excess generation, set it aside, and then return it to the customer-generator at a later time; it meets the instantaneous power needs of the customers at all times. The "banking" concept is strictly related to the net metering accounting rules and is the policy of the Commonwealth. Rather, the Company is describing its obligation to provide its customers with power when called upon, which is a core component of its obligation to serve. It does this the same for customer-generators as it does with non-customer-generators; there is nothing special here in terms of the system usage or subsequent cost-causation of customer-generators.

Q43. HAS THE COMPANY IDENTIFIED ANY SCENARIO IN WHICH THESE NEW "OBLIGATIONS" CANNOT BE HANDLED BY THE EXISTING SYSTEM WITHOUT MODIFICATION?

A43. The Company has not identified any specific issues that directly result from customer-generators being connected to its system. It does mention hypothetical concerns related to power fluctuations from passing clouds, but admits that these types of issues are screened for during the interconnection process, must be remedied and paid for by a customer-generator prior to connecting to the system, and there is "little difference" between solar generation and customer load fluctuation of similar size and timescale.[52]

Q44. DO DISTRIBUTION SYSTEM ASSETS GENERALLY CARE WHICH DIRECTION POWER FLOWS THROUGH THEM?

A44. Generally, no. Poles are structural, not electrical, in nature. Wires are unaffected by the direction of power flow and are only limited by the total power they can carry, and

[51] *Id.*
[52] Exhibit KL-16, SP-III-1.

transformers can typically handle reverse power flows with no impact on operations. There may be some larger switching equipment and voltage control equipment that are not designed to manage two-way flow, but these comprise a small portion of the Company's distribution rate base and the Company has not identified any ratebase-funded upgrades needed to accommodate reverse power flows as those would need to be paid for by the customer-generator as a condition of interconnection.

Q45. IS THE COMPANY'S BILLING DEMAND PROPOSAL REALLY BASED ON "ALL UTILIZATION" OF THE SYSTEM BY ITS CUSTOMERS?

A45. No. For a customer-generator, the Billing Demand is the larger of the peak imported power and the GGR, even if the GGR power equivalent is never actually exported to the grid. Further, the Company has already admitted that its current billing practices are heavily influenced by its use of a 50% demand ratchet, with roughly 50% of customers already being billed not on their actual usage but their ratcheted demand.

Q46. WHAT IS YOUR RECOMMENDATION ON THIS MATTER?

A46. The Company's justification for its Billing Demand proposal is inconsistent and selectively punitive towards customer-generators. It claims that it is proper to base demand charges on "all utilization" for customer-generators, even though it does not do so for non-customer-generators. It claims that customer-generators create additional "obligations" on the system and should thus pay more, despite the complete lack of incremental costs associated with these "obligations." Its updated rate design would increase distribution rates for most non-residential customer-generators by roughly 400% while providing a roughly 11% reduction for non-residential, non-customer-generators, despite no individual customer shifting their behavior in a way that impacts costs. I continue to recommend the Commission reject the Company's Billing Demand proposal as unsupported, not cost-based, and discriminatory towards customer-generators.

E. The Company Misrepresents the Interaction between Customer-Generators and its Default Service Provider Contract.

Q47. WHAT IS ONE OF THE CORE ASSERTIONS OF THE COMPANY IN THIS CASE?

A47. The Company asserts that there is a cost shift that occurs when a customer-generator is paid for its annual excess energy at the GSSR-1 PTC rate.[53] The Company's contends its analysis demonstrates "the limited ability of net-metered [solar PV] to mitigate PJM costs."[54] It continues:

> Additionally, while no quantitative analysis has been performed, basic market principles suggest that as the total volume of energy purchased decreases, the price-per-unit will increase. In essence, as more energy is purchased from net-metered exports, less is purchased through the DSP wholesale contract. This lowers the 'buying power' of the DSP while concentrating non-volumetric (Company and supplier admin costs, Capacity, Transmission, and RTEP) costs across a smaller total quantity purchased, increasing the cost per MWh of default supply.
>
> Finally, as purchased net-metered energy creates net under collection of GSSR costs under the existing structure (where the customer generator receives the GSSR-1 price regardless of the generator's size), the resulting reconciliation in future periods through the E-factor inflates the cost of default supply which, in turn, inflates the purchased cost of future-period net-metered energy purchases. In short, net-metered customer-generators directly benefit from the price inflation that they cause in a compounding fashion that increases as more net-metered generation is installed.
>
> The Company concludes from its analysis that 1) net-metered generation exports result in a significant increase to default supply costs and 2) its proposed tariff change will mitigate these increases by shifting large exporters to the GSSR-2 rate and corresponding reimbursement formula.[55]

Q48. PLEASE DISCUSS YOUR UNDERSTANDING OF THE COMPANY'S DSP CONTRACT.

A48. Based on a review of the recent DSP docket and discovery responses from the Company, it is my understanding that the Company has engaged a wholesale electricity supplier in a "Load-Following Full Requirements contract."[56] The contract requires the supplier to

[53] Exhibit KL-17, SP-II-5 Revised.
[54] *Id.*
[55] *Id.*
[56] Joint Default Service Plan for Citizens' Electric Company of Lewisburg, PA and Wellsboro Electric Company For the Period June 1, 2025 through May 31, 2029 at 1, Docket Number P-2024-3049357, May 31, 2024. ("DSP Plan Application")

deliver all necessary energy to the Company's PJM pricing node and allows the supplier to directly pass through many costs, including those for transmission and generation capacity and PJM's Regional Transmission Expansion Plan/Transmission Enhancement Costs ("RTEP/TEC"). It prices energy using a six-month laddered approach, where a 12-month strip of forward prices for the monthly PJM West Hub on-peak price are triggered every six months for half of the anticipated load.[57]

The contract also includes a "Supplier Adder", which includes the following:

> The Supplier Adder covers all other costs to deliver default service power (both fixed and hourly energy) to the wholesale meter at the Citizens' or Wellsboro Aggregate Bus. This includes congestion, marginal losses, Alternative Energy Portfolio Standards ("AEPS") Act compliance, and transmission losses, as well as all risks associated with default service customer usage variability, customer migration (switching to an EGS for supply service or returning to default service as permitted under the Companies' tariffs and Pennsylvania law) and deviations between the forward pricing and actual costs.[58]

The Company elaborated on the purpose of the Supplier Adder:

> On top of the respective energy component charges, Citizens' and Wellsboro will pay a Supplier Adder* to their wholesale supplier, which will be a uniform cents-per-kWh charge fixed for the duration of the 4-year contract. The Supplier Adder will compensate the wholesale suppliers for all costs and risks for delivery to the wholesale meter for the Citizens' or Wellsboro Aggregate Bus, including marginal losses, ancillary services, congestion, transmission charges (other than NITS and RTEP/TEC), AEPS costs, marginal losses, customer load variability, and customer migration. Importantly, the Supplier Adder avoids the need for the Companies to maintain congestion management plans, as wholesale suppliers would continue to assume congestion costs and the associated rights to Auction Revenue Rights "ARR" and Financial Transmission Rights "FTR".
>
> *The Supplier Adder will place the risk of deviations in actual versus forward energy costs, sales, on-peak/off-peak customer usage and on-peak/off-peak wholesale pricing differentials on the wholesale supplier.[59]

Q49. HAS THE COMPANY'S LATEST DSP PLAN BEEN APPROVED?

[57] DSP Plan Application at 12.
[58] *Id.*
[59] *Id.* at 14.

A49. Yes. The Company's DSP Plan was approved by the Commission on January 23, 2025, and will be in effect from June 1, 2025, through May 31, 2029.[60] Unless subsequently modified by agreement of all parties, the pricing methodology and Supplier Adder will be locked in for the next roughly four years.

Q50. GIVEN ALL OF THE COSTS AND RISKS THAT ARE INCLUDED IN THE SUPPLIER ADDER, HOW MUCH DID THE WINNING BIDDER OF THE CONTRACT CHARGE FOR THIS ITEM?

A50. The winning bidder not only did not charge a premium for the Supplier Adder, it offered and won with a Supplier Adder credit of $2.66/MWh.[61] In other words, for every MWh that the supplier bills the Company for default service, it reduces the cost by $2.66/MWh.

Q51. HOW DOES THIS COMPARE TO THE SUPPLIER ADDER IN THE PRIOR DSP PLAN?

A51. The Supplier Adder in the prior DSP period from June 1, 2021, through May 31, 2025, was $1.37/MWh.[62] In this procurement, the winning bidder had a Supplier Adder that was $4.03/MWh lower, a considerable drop from the prior plan.

Q52. DID THE COMPANY MAKE ANY STRUCTURAL CHANGES TO THE CURRENT DSP PLAN THAT MIGHT HAVE IMPACTED THIS FIGURE?

A52. Potentially. The Company requested and was approved a "minor modification" to the energy pricing formula trigger date.[63] Instead of providing notice to the supplier on a day-ahead basis, the Company switched to a same-day trigger process. This reduces the risk that market prices move substantially between when the trigger is executed and when the actual prices are locked in.

Q53. DO YOU BELIEVE THIS MODIFICATION WAS RESPONSIBLE FOR A MEANINGFUL PART OF THE REDUCTION OF THE SUPPLIER ADDER?

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[60] Commission Order, Dockets P-2024-3049357, January 23, 2025.
[61] Citizens' Electric Company of Lewisburg, PA Generation Supply Service Rate Filing; Supplement No. 171 to Tariff Electric PA. P.U.C. No. 14; Docket No -2024-3049357
[62] Citizens' Electric Company of Lewisburg, PA Disclosure of Default Service Solicitation Results June 1, 2021 through May 31, 2025. Available at https://citizenselectric.com/wp-content/uploads/2021/04/Citizens-2021-Default-Service-Supply-Bid-Disclosure-A8029446.pdf
[63] DSP Plan Application at 13.

A53. It is obviously not possible to determine exactly what thought process the winning bidder used in setting its Supplier Adder, but one can examine the degree to which PJM monthly forward contracts change in price on a day-to-day basis. In reviewing data on CME Group's website, while there were some days which future contract prices changed by several $/MWh on subsequent days, most days saw much smaller changes measured in the cents/MWh.[64] As such, it is unlikely that this change alone resulted in the sizeable drop of the Supply Adder in this procurement.

Q54. WERE THE ISSUES THAT ARE AT PLAY IN THIS DOCKET PRESENT DURING THE TIME WHEN BIDDERS WERE PARTICIPATING IN THE DSP PROCUREMENT PROCESS?

A54. Yes. The Company's DSP Plan was not approved until the end of January 2025. The ability of large customer-generators to produce substantial amounts of excess generation and be compensated on the GSSR-1 tariff was in place at that time. In fact, the Company did not file the application in this docket until April 30, 2025, which was after its compliance filing on April 17, 2025, in the DSP Plan reporting the results of the finalized procurement.

Mr. Johnson testified that the Company "did not provide any party or customer with advanced briefings on the various proposals or content of the rate filing until it was submitted."[65] In other words, the suppliers that bid in the DSP Plan procurement in early 2025 would have had no public knowledge at the time of the Company's plan to modify its default supply classification process.

Q55. DID ANY PARTY DISCUSS THE POSSIBILITY THAT SUPPLIERS WOULD ADD A LARGER "RISK PREMIUM" TO THEIR BIDS BECAUSE OF SOME OF THE RISKS ASSOCIATED WITH CUSTOMER-GENERATORS AND NET METERING?

[64] Several different futures contracts were examined roughly a year before their covered date at https://www.cmegroup.com/markets/energy/electricity/pjm-western-hub-peak-calendar-month-real-time-lmp.quotes.html

[65] Johnson Rebuttal at 34.

A55. Yes. While discussing the UGI Electric Default Service Plan order in his rebuttal testimony, OCA Witness Zach Teti noted that UGI raised three issues related customer-generators and its DSP procurement:

> (1) their output would decrease GSR-1 group load and tranche size; (2) there is substantial question as to the level of output and timing of when these projects will become operational; and (3) these large customer-generators have the ability to leave default service at any time and participate in the wholesale market, thereby creating an attrition risk if projects opt to leave GSR-1 service and shop their output elsewhere.[66]

In his own discussion of this issue, Mr. Teti stated

> While the Company did not show this effect in their analysis, the Company and I share the concern about the risk premiums associated with customer-generator uncertainty described in the above excerpt of the PUC's Opinion and Order. In the above remark, the Company expresses a comparable concern: that a large customer-generator stands to benefit from "price inflation that they cause in a compounding fashion." I take this statement to mean that the large customer-generator (output capacity > 400 kW) stands to benefit from higher prices caused by the risk premiums added to DSP suppliers to address their risks caused by unknown output quantities and attrition risk of large customer-generators.[67]

Q56. BASED ON THE LATEST DSP PROCUREMENT, DOES THIS SEEM TO BE AN ONGOING CONCERN?

A56. No. The most recent DSP procurement for the Company resulted in a substantial decrease in the Supplier Adder, which includes, among other things, all the risks identified in the UGI order above. The winning bidder was clearly sufficiently comfortable, even with those open issues, to undercut the prior Supplier Adder by more than $4.00/MWh. Further, even if suppliers were concerned about these developments, the Company's customers will be served for nearly four years before the issue will come up again. Given the myriad changes to the PJM market, including data center load growth, state and federal policy changes, and market design reforms that are likely to occur over the coming four years, there will be many other issue that will impact future DSP procurements than just those issues being addressed in this case.

[66] Teti Rebuttal at 11, quoting the PUC Decision in Docket P-2024-3049343 at 23.
[67] Teti Rebuttal at 12.

Q57. RETURNING TO THE INTERACTION OF THE DSP CONTRACT AND THE POTENTIAL COST IMPACT OF CUSTOMER-GENERATORS TAKING SERVICE ON THE GSSR-1 TARIFF, WHAT ANALYSIS DID THE COMPANY PRODUCE?

A57. The Company produced an analysis that purported to show that a 400 kW_{AC} rooftop system with no offsetting load could increase DSP costs by roughly $27,000 per year, while a 3 MW_{AC} ground mount single-axis tracking system with no offsetting load could increase DSP costs by $230,000 per year.[68] In calculating these figures, the Company assumed that it pays the full retail PTC to customer-generators for their excess energy, but only offsets the energy portion of the DSP contract when that generation reduces the energy that the wholesale supplier must provide to the Company. In other words, it provides zero value for any offset of generation capacity, transmission capacity, or RTEP/TEC costs, all of which are based on the peak load being provided by the wholesale supplier.

Q58. WHAT JUSTIFICATION DID THE COMPANY PROVIDE FOR THIS APPROACH?

A58. It provided four explanations, summarized below:

- NEM systems are not dispatchable
- GSSR-1 customers benefit from high PTC costs, providing an incentive to increase the costs
- Solar systems have a low demonstrated coincidence with peak demand periods.
- NEM generation is volatile and impacted by weather.[69]

Based on these factors, the Company "does not believe it is appropriate to incorporate any capacity or transmission impact into its analysis, however, because net-metered generation does not guarantee those savings and is economically disincentivized to export during peak demand periods."[70]

Q59. DO ANY OF THESE FACTORS MATTER IN TERMS OF HOW THE DSP CONTRACT IS STRUCTURED?

[68] Exhibit KL-17, SP-II-5 Revision 1.
[69] Exhibit KL-18, OCA-XV-1.
[70] Exhibit KL-19, OCA-XV-2.

A59. No. The fact that NEM systems are not dispatchable is irrelevant. The wholesale supplier is responsible for dispatching the anticipated DSP load on a day-ahead basis through the PJM scheduling process.[71] If the supplier chooses, it can include expected generation from customer-generators in its load assumptions. During the settlement process, any differences between scheduled and actual load are reconciled. All risks associated with any load variability from the DSP customers falls on the supplier and is one of the enumerated components of the Supplier Adder discussed above. This includes any failure to accurately forecast net load and any costs that may be needed to reconcile that load in the real-time market.

The remaining points do not support the Company's conclusion that solar should be afforded zero credit against PJM capacity costs. Because the customer-generators are connected to the distribution grid "downstream" of the PJM settlement point, and because the quantity of net metering capacity is substantially lower than the peak demand of the Company, every kW of power that is produced on the Company's distribution grid is consumed on the Company's distribution grid by another customer. As such, every kW of power that is being generated during one of the five coincident peak ("5CP") hours that determines cost allocation in the PJM market will reduce the amount of capacity that is assigned to the wholesale supplier. Given that the supplier passes these costs directly through to the Company, there is a 1:1 reduction in load obligations based on the generation in those hours.[72]

Q60. DO CUSTOMER-GENERATORS HAVE TO BE PRODUCING AT 100% OF THEIR GGR TO REDUCE PJM COSTS?

A60. No. The Company's argument that solar is intermittent and may not be producing during peak hours has nothing to do with the post hoc analysis that PJM uses to allocate costs. If

[71] Exhibit KL-20, SP-VI-17.

[72] There is a one year delay in when these reductions impact the load obligation, but they will be fully reflected in the PTC for the following energy year.

the system was producing power during a 5CP hour, it will be credited for that power, regardless of the ex ante probability of the generation during that 5CP hour.

Q61. HAVE YOU REVIEWED THE COMPANY'S ANALYSIS SUGGESTING THAT SOLAR IS POORLY CORRELATED WITH PEAK HOURS?

A61. Yes. As with the Company's other analysis that I discussed in my direct testimony, it contains a number of errors and improper methodological choices that artificially depress the result.

The Company was made aware of one such mistake where it improperly accounted for the AC to DC ratio of the system and issued a revised workpaper.[73] However, several other methodological issues remain. First, the Company again failed to adjust its modeled solar generation for Daylight Saving Time. For most of the year, this resulted in using solar generation from an hour later than was appropriate, and given the PJM 5CP hours tend to fall during late summer afternoons, this had a sizable impact on the forecasted generation.

Second, in using PVWatts, the Company utilized a typical meteorological year ("TMY") weather file for its modeled generation. TMY files are comprised of actual weather data from many different years that are specifically selected to represent "typical" weather conditions over the full year. The result of simulated generation using TMY files is more likely to represent the long-term average generation in a given location, but it is inappropriate to use when analyzing generation on a specific day at a specific time.

The PJM systems tends to peak during hot, summer afternoons. Hot summer afternoons are often sunny, meaning that solar production may be above average for that time of year. If the TMY file contained July weather from 2007, then the generation using that weather file on July 27th, 2007 at 5 PM EPT will not match the weather

[73] Exhibit KL-17, SP-II-5 Revision 1.

conditions that led to July 27th, 2023 at 5 PM EPT to be a 5CP hour. A proper analysis must include weather that corresponds to the grid conditions in place at the time.

Finally, the Company's analysis includes 5CP data going back to 2015, but fails to recognize what is a clear trend in the transmission cost allocation hours. Between 2015 and 2019, 18 of the 25 5CP hours for transmission cost allocation occurred during non-summer months. But between 2020 and 2024, only 4 of the 25 hours occurred outside the summer.[74] PPL, the transmission system in which the Company operates, is clearly shifting from winter to summer, and as a result, including data from the winter months from 10 years ago in the performance average is no longer appropriate.

Q62. WERE YOU ABLE TO FIX THE COMPANY'S ANALYSIS?

A62. Yes. I used the National Renewable Energy Laboratory's System Advisor Model ("SAM"), which is a more sophisticated version of its PVWatts tool, to replicate system generation using actual weather files from 2015 through 2024.[75] I fixed the Daylight Saving Time issue and recalculated the average performance during the 5CP hours from the past five years. The results are found below in Table 3.

	400 Kw Fixed Tilt		**3 MW Tracker**	
% of Nameplate during 5CP Hours	PLC Gen. Capacity	NSPL Trans. Capacity	PLC Gen. Capacity	NSPL Trans. Capacity
Original	25.4%	20.9%	39.9%	27.2%
Corrected	41.8%	35.0%	65.2%	50.1%
Change	**164.6%**	**167.4%**	**163.7%**	**184.0%**

Table 3 – Average Solar Contribution during 5CP Hours 2020-2024.

Q63. HOW DO YOU INTERPRET THESE RESULTS?

A63. The corrections increased the Company's original solar capacity contribution values by 64% to 84%. Further, the corrected results demonstrate that solar PV provides meaningful generation during the 5CP hours for both generation and transmission cost

[74] Exh. KL-17, SP-II-5 Attachment B
[75] https://sam.nrel.gov/

allocation purposes, particularly for the 3 MW tracking system. It is correct that these values are lower than the GGR of these systems, but these values are more than sufficient to discredit the Company's position that solar should get no capacity reduction credit for generation and transmission costs.

Q64. HOW DO YOU ANTICIPATE THE COMPANY RESPONDING TO THIS ANALYSIS?

A64. I suspect they will acknowledge the methodological shortfalls of their original analysis, but would still argue that because solar has a relatively low capacity factor and is not perfectly correlated with the 5CP hours, it is still causing a cost shift when paid the full PTC.[76]

Q65. DO YOU HAVE ANY ADDITIONAL INSIGHT INTO THAT ISSUE?

A65. Yes. It is important to consider the implications of the result. In the location simulated by the Company, solar production from a single-axis tracker is on average 18.8% of its GGR over the course of a year, while that of a fixed-tilt system is 16.7% of its GGR over the course of a year.[77] But during the peak hours, generation is 2-2.5 higher for fixed-tilt systems, and 2.7-3.5 times higher for single-axis tracking system. In other words, the solar systems outperform during peak hours compared to the total number of MWh they generate.

This has meaningful implications for the Company's PTC contract. In the Company's DSP Plan Compliance Filing, it broke down its calculation for the PTC.[78] Energy costs are calculated based on monthly forward pricing from PJM Western Hub futures contracts. Generation and Transmission capacity costs are converted from dollars to a $/kWh rate by multiplying the total capacity obligation in MW, the corresponding

[76] The Company may also disagree on the appropriateness of using only the past 5 years to reflect the shift in transmission peaks to the summer months. However, the trend in the data is clear, and given that cost allocation is based on actual and not projected data, I continue to recommend this adjustment.
[77] Exh. KL-17, SP-II-5 Attachment B (REV). The Company modeled zip code 17837. The values above represent the capacity factor of solar in that location.
[78] GSSR-1, GSSR-2 ADJ; SUPP NO 171 TO PA PUC NO 14; EFF: 6/1/25 - CITIZENS' ELECTRIC CO OF LEWISBURG, Docket No. P-2024-3049357. ("DSP Plan Compliance Filing") Available at https://www.puc.pa.gov/pcdocs/1875351.pdf

capacity rate in $/MW-day, and the number of days in a year, and finally divided by the total forecasted sales.

The Company performs these calculations for its projected PTC for June 1, 2025, through November 30, 2025, but also includes sales forecast data through May 30, 2026.[79] As such, it is possible to compare the avoided cost value of the generation profile of a fixed-tilt and single-axis tracking solar system against the cost of serving the load profile of the entire DSP load.

Q66. DID YOU PERFORM THESE CALCULATIONS?

A66. Yes, I did. I used solar generation from the TMY weather file for the avoided energy cost calculations given this analysis is for an unspecified period of time. I also used my updated generation and transmission capacity contribution calculations discussed above to calculate the avoided capacity cost values. The results of this calculation are shown below in Table 4.

	400 kW Fixed Tilt	3 MW Tracker	GSSR-1 Load Forecast
Annual Generation / Load MWh	567.9	5,333.2	114,007.0
Gen Capacity Contribution	41.8%	65.2%	
Gen Capacity MW	0.17	1.96	22.86
Gen Rate $/MW-Day	$270.43	$270.43	$270.43
Gen $	$16,487	$193,182	$2,255,947
Gen Rate $/MWh	**$29.03**	**$36.22**	**$19.23**
Trans Capacity Contribution	35.0%	50.1%	
Trans Capacity MW	0.14	1.50	24.90
Trans Rate $/MW-Day	$297.57	$297.57	$297.57
Trans $	$15,221	$163,290	$2,704,465
Trans Rate $/MWh	**$26.80**	**$30.62**	**$23.05**
Energy Rate $/MWh	**$66.82**	**$66.82**	**$66.82**
Total Rate $/MWh	**$122.66**	**$133.66**	**$109.10**

Table 4 – Solar Avoided Cost vs. DSP Load Profile Cost

Q67. HOW DO YOU INTERPRET THESE RESULTS?

[79] DSP Plan Compliance Filing, Schedules 1-12. The energy price for the second 6-month period will change when the new 12-month future contract is locked in. However, the analysis uses the currently 12-month future strip for the analysis as this is the only value available at this time.

A67. The analysis above duplicates the cost for the wholesale supplier of serving a load profile that is identical to the generation profile of the two solar systems. I followed the same steps to calculate the resulting $/MWh rate using the relative quantities of energy, generation capacity, and transmission capacity.[80] The result shows that the cost of serving the solar generation "load profile" is higher than the cost of serving the DSP load profile. Of course, this means the inverse is true: avoiding energy and capacity due to the solar generation profile is worth more than the average cost to serve the DSP load profile.

For the 400 kW_{AC} fixed-tilt system, I calculated an avoided cost benefit of $122.66/MWh, which is $13.56/MWh or 12% higher than the corresponding PTC components cost of $109.10/MWh. For the 3 MWAC tracking system, the avoided cost benefit was even higher at $133.66/MWh, which is $24.57/MWh or 23% higher than the corresponding PTC components. In short, paying customer-generators the PTC for their solar generation does not cause a cost shift to non-solar customers, it in fact undercompensates the solar system's contribution to reducing costs.

Q68. THE FIGURES ABOVE ARE BASED ON YOUR ADJUSTMENTS TO SOLAR'S CAPACITY CONTRIBUTION. WHAT IF THE COMMISSION DISAGREES WITH SHORTENING THE TIME HORIZON TO FIVE YEARS?

A68. If one only corrects the clear methodological errors of the Company's analysis of failing to adjust for Daylight Saving Time and using actual weather data from each year, but still uses the full 10-year average that the Company used, the result is directionally the same. The avoided cost benefits fall slightly to $116.67/MWh for the fixed-tilt system and $125.62/MWh for the tracking system, but these are still comfortably above the corresponding PTC component rate of $109.10/MWh.

[80] I did not include the RTEP/TEC costs as these are minor ($0.94/MWh) and the DSP Compliance Plan did not describe the calculation methodology. I also did not include the Admin costs, which are also minor ($1.35/MWh) and would be skewed by the relatively small quantity of solar generation. Finally, I did not include any distribution loss adjustment as it was unclear whether the Company's load forecast already included this value or not when calculating the final $66.82/MWh rate.

Q69. BUT IF SOLAR IS NOT PRODUCING AT ITS FULL GGR DURING THE PEAK HOURS, AND HAS A LOWER CAPACITY FACTOR THAN THE COMPANY'S DSP LOAD FACTOR, HOW DO YOU EXPLAIN THE ABOVE RESULT?

A69. Another way to analyze the avoided cost benefits is to look at the relative share of each PTC component on a dollar basis. As shown below in Figure 2, the solar generation profiles are "overweighted" in capacity compared to energy. This reflects solar's higher-than-average generation during the 5CP hours compared to the total quantity of generation over the course of the year when compared to the same peak load / total energy ratio of the DSP load profile. The result of this is that outsized avoided capacity benefits are "concentrated" into a small number of annual generation MWh, resulting in the higher rates above.

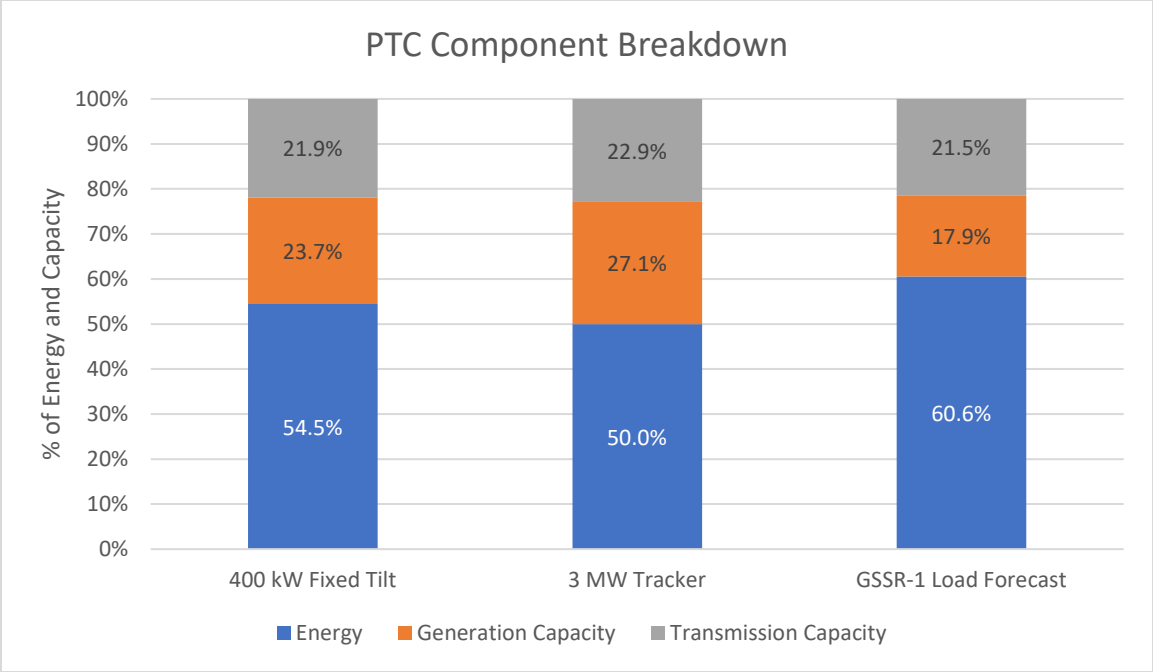

Figure 2 - PTC Component Breakdown

Q70. BUT DOESN'T THE LOWER AMOUNT OF GENERATION FROM A SOLAR SYSTEM IMPROPERLY INFLATE THE SOLAR RATE CALCULATION COMPARED TO THE LOAD PROFILE RATE CALCULATION?

A70. No. Although one might think that dividing the avoided capacity cost benefits by a smaller number of MWh artificially inflates the rates above, there is a simple way to prove this is not true: comparing the cost to serve the DSP load with and without a solar generator.

Because of the capacity cost pass-through and energy cost index structure of the DSP contract, the Company is only obligated to pay for the actual energy and capacity that its DSP customers use. If they use less energy because of distribution-connected solar systems, then the wholesale supplier has to deliver less of this product. If they have lower demand during the 5CP hours because of solar generation, the capacity cost allocation will be proportionately lower. The specific ratio of these decreases will determine whether the overall PTC rate increases or falls as it will be calculated based on the total capacity dollars divided by the total sales.[81]

Q71. WHAT IS THE RESULT OF THIS ANALYSIS?

A71. The results are shown in Table 5 below for the GSSR-1 load net of the fixed-tilt and tracking system. As expected, the rate to serve the GSSR-1 load net of either solar system is lower than the rate to serve the GSSR-1 load by itself, and the rate to serve the load net of the tracker is lower than to serve the load net of the fixed tilt. This is due to the greater reduction in capacity costs than the reduction in total energy in both, but a more pronounced difference in the tracker.

[81] Because of the contract structure, the energy component of the PTC rate remains constant regardless of the number of sales.

	GSSR-1 Load Forecast	Load Less Fixed Tilt	Load Less Tracker
Annual Load MWh	**114,007**	**113,439**	**108,674**
Gen Capacity MW	22.86	22.69	20.90
Gen Rate $/MW-Day	$270.43	$270.43	$270.43
Gen $	$2,255,947	$2,239,460	$2,062,765
Gen Rate $/MWh	**$19.23**	**$19.18**	**$18.42**
Trans Capacity MW	24.90	24.76	23.40
Trans Rate $/MW-Day	$297.57	$270.43	$270.43
Trans $	$2,704,465	$2,443,970	$2,309,406
Trans Rate $/MWh	**$23.05**	**$20.93**	**$20.62**
Energy Rate $/MWh	**$66.82**	**$66.82**	**$66.82**
Total Rate $/MWh	**$109.10**	**$106.93**	**$105.86**

Table 5 – DSP Load Profile Net of Solar Generation

Q72. THE ANALYSIS ABOVE ASSUMES THAT THERE IS NO LOAD TO OFFSET THE PV SYSTEM. DOES THIS ANALYSIS CHANGE IF THESE ARE BTM SYSTEMS THAT ARE INSTEAD OFFSETTING LOAD?

A72. No. The DSP contract is for delivery of all aggregated load at the Company's 69 kV St. Mary's substation.[82] Whether customer-generator uses this energy onsite or exports it to serve its neighbor's load, the net result at the St. Mary's substation is a reduction equal to the solar generation plus distribution line losses.

Q73. THE COMPANY CLAIMS THAT CUSTOMER-GENERATORS WILL BENEFIT "IN A COMPOUNDING FASHION" THROUGH THE INTERACTION OF NETTING ENERGY AND THE GSSR-1 RECONCILIATION FACTOR.[83] DO YOU AGREE WITH THIS STATEMENT?

A73. No, I do not. First, it is important to understand the scale of the DSP contract cost and the potential under-collection due to excess annual energy. The Company reported that customer-generators had accumulated a grand total of 636 MWh of net excess energy at the end of energy year 2025.[84] Even assuming that 100% of these customers are served on the GSSR-1 tariff, at the current PTC of $114.19/MWh, this represents payouts of

[82] DSP Plan, Exhibit NJ-3 at 3.
[83] Exhibit KL-17, SP-II-5 Revision 1.
[84] Exhibit KL-21, SP-IV-13.

approximately $73,000. By contrast, the DSP Plan is projected to collect roughly $13 million in energy year 2026.[85] Even if this excess energy caused a shortfall to be collected in future periods, it would only increase the rate from $114.19/MWh to $114.83/MWh. Given the average commercial customer with excess annual energy only had 58 MWh of banked generation at the end of the year, the reconciliation adjustment discussed above would on average result in an extra $35 or so.[86] This is hardly noticeable compared to the sizable increase these customers would experience under the proposed Billing Demand definition.

More to the point, the Company should be including anticipated generation from customer-generators in the sales forecast used to calculate the GSSR-1 capacity components. If the Company correctly includes these values for its existing and in-progress fleet, then the only potential under-collection due to unplanned excess generation would be from new systems that were conceived and built within the energy year and resulted in excess annual generation for the customer-generator. Given the Company updates its PTC every six months, this is an extremely unlikely scenario.

Finally, even if there were unplanned excess generation that resulted in under-collections in the GSSR-1 account, as shown above, that generation will contribute more to reducing capacity costs than reducing energy sales. When the following year's load obligations are released, they will be lower than they would have been absent the solar generation, which will reduce costs for all customers on the GSSR-1 tariff.

III. REBUTTAL OF OCA WITNESSES ZACH TETI

Q74. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

[85] DSP Plan Compliance Filing, Schedule 3. The Company forecasts 114,007 MWh of GSSR-1 sales at $114.19, which would result in collections of $13,018,459.
[86] Exhibit KL-21, SP-IV-13. There were 10 commercial customers with a total of 577 MWh of excess energy.

A74. In this section of testimony, I discuss the rebuttal testimony of OCA witnesses Zach Teti.[87]

Q75. PLEASE SUMMARIZE THE RELEVANT POSITIONS OF OCA'S REBUTTAL TESTIMONY.

A75. OCA witness Mr. Teti supports the approval of the Company's Billing Demand proposal, indicating his belief that the "overall default service supply portfolio and the specific default service procured on behalf of residential customers would benefit from the Company's proposed Billing Demand methodology."[88]

Q76. DOES MR. TETI PROVIDE ANY INDEPENDENT ANALYSIS OR REASONING TO SUPPORT HIS RECOMMENDATION?

A76. No. Mr. Teti repeats the Company's position, but does not independently discuss or analyze the Billing Demand proposal.[89] In doing so, he adopts the Company's arguments but does not offer any new insight or critiques of those arguments. For instance, he does not discuss the problems with charging customers for demand that they do not place on the system, nor does he question the Company's analysis provided in SP-II-5 Attachment A. In follow up discovery, Mr. Teti admitted that he "did not independently validate the quantitative approach by reconciling/cross-checking monetary values and magnitude of costs."[90] Given the myriad errors identified in the latter analysis in my direct testimony, Mr. Teti's failure to scrutinize the workpapers may have contributed to his acceptance of the problematic results.[91]

Mr. Teti was not able to independently validate the Company's explanation of how demand reductions from customer-generators impact PJM wholesale costs because of some ambiguity in the Company's discovery responses.[92] Mr. Teti did submit

[87] OCA Statement No. 5R - Rebuttal Testimony of Zach Teti on Behalf of the Pennsylvania Office of Consumer Advocate ("Teti Rebuttal").
[88] Teti Rebuttal at 3.
[89] Teti Rebuttal at 6.
[90] Exhibit KL-22, OCA Response to Solar Projects I-2.
[91] See e.g. Solar Projects' Statement No. 2, Direct Testimony of Kevin Lucas at 9-12 ("Lucas Direct").
[92] Teti Rebuttal at 10, footnote 13.

discovery to follow up on this issue, but it was not received before the filing deadline for his rebuttal testimony.

Q77. HAS THE COMPANY SINCE PROVIDED RESPONSES TO MR. TETI'S DISCOVERY?

A77. Yes, they have.[93]

Q78. AND DID THE DISCOVERY CLARIFY THE ISSUE?

A78. No, it did not. Mr. Teti asked the company "Please refer to "Attachment A (Rev)" of Citizens' response to SP-II-5, specifically in the portion that states: 'PJM costs substantially unaffected by net metered sales.' Please explain the effect of net metered sales on PJM costs."[94]

The Company's response did not address the core issue: how do net metered sales, including excess generation from both customer-sited behind-the-meter ("BTM") systems and distribution-connected commercial scale the PJM settlement process and the default service provider's ("DSP") full requirements contract. Instead, the Company reiterated its generic observations about net metered solar; namely, that it is not dispatchable, that solar generation does not peak at the same time as the system peak, and that excess generation is volatile.[95]

Q79. ARE THESE OBSERVATIONS RELEVANT TO THE MECHANICS OF THE PJM SETTLEMENT PROCESS AND THE DSP CONTRACT?

A79. No, they are not. The lack of dispatchability does not matter; these are not capacity resources that must have a specific capacity accreditation in the PJM wholesale market and are held accountable for their output during peak days. The observation that solar generation does not peak during the system peak hours does not mean that solar cannot and does not provide peak demand reductions; it does, albeit at a level that is lower than the GGR of the system. Similarly, the day-to-day volatility of an individual solar generator is smoothed out across a wider geographic area, and system operators

[93] Exhibit KL-18, Citizens' response to OCA-XV-1.
[94] Id.
[95] Id.

understand that solar generation has a diurnal generation profile and can plan the system around this fact.

Q80. WHAT APPEARS TO BE OCA'S MAIN CONCERN RELATED TO THE OPERATING CHARACTERISTICS OF DISTRIBUTION-CONNECTED DG SYSTEMS?

A80. Mr. Teti notes a concern that DSP providers will increase their bids to reflect a "risk premium" associated with the distribution-connected DG systems.[96] He also notes a Company concern about large customer-generators "benefiting from 'price inflation that they cause in a compounding fashion.'"[97] Notably, neither of these concerns has anything to do with the establishment of base distribution rates, which is ostensibly the purpose of this proceeding. They are exclusively related to the issue of DSP procurement, which should be litigated in a DSP proceeding. This proceeding is simply the wrong forum to address DSP-related matters.

Q81. HAS OCA PERFORMED ANY ANALYSIS RELATED TO THE PURPORTED UPWARD PRESSURE ON BIDS CAUSED BY THIS RISK PREMIUM?

A81. No, it has not for the understandable reason that "OCA is not permitted to see bid details following the completion of default service procurement auctions."[98] It is problematic that the office responsible for representing consumers in front of the Commission is not able to investigate one of the more speculative elements supporting a large change to customer-generator compensation.

Q82. ARE THERE OTHER ISSUES THAT MR. TETI RAISES REGARDING THE COMPANY'S TESTIMONY AND TARIFFS?

A82. Yes. Mr. Teti notes several instances of ambiguity and lack of clarity in the Company's testimony, discovery responses, and tariffs regarding how PJM costs are impacted by distribution-connected DG systems.[99] The follow-up discovery that Mr. Teti asked did

[96] Teti Rebuttal at 12.
[97] Teti Rebuttal at 12.
[98] Exhibit KL-22, OCA Response to Solar Projects Set I-3.b
[99] Teti Rebuttal at 16.

not resolve these issues, and it appears the record continues to lack clarity on how exported generation is incorporated into the PJM settlement process and how that impacts DSP costs.

Q83. DO YOU AGREE THERE IS A LACK OF CLARITY?

A83. Yes. I do not believe that the Company has directly answered OCA's questions on this matter, as discussed above. This is yet another reason that issues related to DSP costs should be fully litigated in a DSP proceeding where parties could properly clarify the record on these issues. Making a decision in this rate case docket while key questions related to supply costs for the DSP remain unanswered would be improper.

Q84. DOES THIS CONCLUDE YOUR TESTIMONY?

A84. Yes, it does.

ORIGINAL

Exhibit Nos. KL-8 through KL-23

ORIGINAL

EXHIBIT KL-8

ORIGINAL

CITIZENS' ELECTRIC COMPANY OF LEWISBURG, PA
DOCKET NO. R-2025-3054394

SP-VI-5

Please refer to Citizens' Statement No. 4R at 23, which states "Second, I disagree with the implication that a customer who installs on-site generation with capacity that exceeds the historic account generation demand is not changing its use of the distribution system. The customer is placing a new obligation on Citizens' and on the distribution system by exporting more energy than it previously imported, and then expecting the return of the "banked" excess supply on-demand."

a. Confirm that a distribution asset that is able to serve a given level of peak demand can also serve all levels of demand up to that level of peak demand. That is, if a piece of equipment can serve 100 kW of demand, it can also serve demands from 0 to 100 kW. If deny, please explain in detail.

b. Is it the Company's position that the new "obligations" discussed above always result in incremental costs to serve its customers? If so, please provide all analyses that the Company has performed to support that position.

c. If the new "obligations" above do not result in incremental costs to serve its customers, does the Company believe it is appropriate to charge the customer-generator more after installing the on-stie generation? Please explain in full.

Response Provided By:
Nathan Johnson, President & Chief Executive Officer, Citizens' Electric Company of Lewisburg, PA

Date: August 25, 2025

Response:

a. Confirmed.

b. No, new obligations, whether from newly installed load or generation, or simply changing load characteristics, do not always result in incremental cost increases to operate and maintain the system; however, the new obligations may support changing the account's proportionate cost responsibility for the shared distribution resources.

c. Yes, just as obligations from new or increased load that increase peak consumed demand will result in increased charges to customers—regardless of whether specific, measurable incremental cost increases can be directly correlated to the new load—the Company proposes to charge exported 'demand' in a similar manner. The Company cannot reasonably calculate the exact incremental costs incurred by each individual customer on an ongoing basis, which is one of the reasons why tariffed rates are used. Billing demand

ORIGINAL

EXHIBIT KL-9

ORIGINAL

CITIZENS' ELECTRIC COMPANY OF LEWISBURG, PA
DOCKET NO. R-2025-3054394

SP-VI-5

Please refer to Citizens' Statement No. 4R at 23, which states "Second, I disagree with the implication that a customer who installs on-site generation with capacity that exceeds the historic account generation demand is not changing its use of the distribution system. The customer is placing a new obligation on Citizens' and on the distribution system by exporting more energy than it previously imported, and then expecting the return of the "banked" excess supply on-demand."

a. Confirm that a distribution asset that is able to serve a given level of peak demand can also serve all levels of demand up to that level of peak demand. That is, if a piece of equipment can serve 100 kW of demand, it can also serve demands from 0 to 100 kW. If deny, please explain in detail.

b. Is it the Company's position that the new "obligations" discussed above always result in incremental costs to serve its customers? If so, please provide all analyses that the Company has performed to support that position.

c. If the new "obligations" above do not result in incremental costs to serve its customers, does the Company believe it is appropriate to charge the customer-generator more after installing the on-stie generation? Please explain in full.

Response Provided By:
Nathan Johnson, President & Chief Executive Officer, Citizens' Electric Company of Lewisburg, PA

Date: August 25, 2025

Response:

a. Confirmed.

b. No, new obligations, whether from newly installed load or generation, or simply changing load characteristics, do not always result in incremental cost increases to operate and maintain the system; however, the new obligations may support changing the account's proportionate cost responsibility for the shared distribution resources.

c. Yes, just as obligations from new or increased load that increase peak consumed demand will result in increased charges to customers—regardless of whether specific, measurable incremental cost increases can be directly correlated to the new load—the Company proposes to charge exported 'demand' in a similar manner. The Company cannot reasonably calculate the exact incremental costs incurred by each individual customer on an ongoing basis, which is one of the reasons why tariffed rates are used. Billing demand

ORIGINAL

EXHIBIT KL-10

ORIGINAL

CITIZENS' ELECTRIC COMPANY OF LEWISBURG, PA
DOCKET NO. R-2025-3054394

SP-I-19

Do customer generators primarily exporting 450 kW net metered systems pay for electrical infrastructure upgrades needed to interconnect to the grid safely?

Response Provided By:
Nathan Johnson, President & CEO, Citizens' Electric Company

Date: June 26, 2025

Response:

Net-metered customer-generators must pay for required system upgrades, based on location-specific distribution system characteristics, needed for their system to safely interconnect and operate in parallel with the Company's distribution system.

ORIGINAL

EXHIBIT KL-11

ORIGINAL

CITIZENS' ELECTRIC COMPANY OF LEWISBURG, PA
DOCKET NO. R-2025-3054394

SP-I-20

Do customer generators pay for a detailed engineering study to ensure a net metering system will not cause adverse grid conditions as a result of their interconnection?

Response Provided By:
Nathan Johnson, President & CEO, Citizens' Electric Company

Date: June 26, 2025

Response:

Yes, customer-generators are required to pay for detailed engineering, as necessitated by location-specific distribution system characteristics, to ensure safe interconnection.

ORIGINAL

EXHIBIT KL-12

ORIGINAL

CITIZENS' ELECTRIC COMPANY OF LEWISBURG, PA
DOCKET NO. R-2025-3054394

SP-V-2

Please refer to Statement No. 1R at 17, which states "The Company must stand ready to serve both of these loads, at any time, in either direction. Whether the customer is drawing 400 kW from the grid, or injecting 400 kW, the Company needs the same assets to serve the customer's needs."

a. Suppose a customer with a 400 kW peak demand is on a feeder that serves 3 MW of peak demand from all customers connected to that feeder. Further suppose that this customer installs a solar generator that enables it to export 400 kW of power to the grid, and that this generator passed the Company's interconnection screening process without triggering any system upgrade costs.

   i. Please indicate all additional pieces of equipment that the Company must install to serve the 400 kW of exported power that did not already exist to serve the 400 kW of imported power.

   ii. Please identify any incremental cost associated with serving the 400 kW of exported power that are solely the result of the presence of exported power and were not required to serve the 400 kW of imported power.

   iii. Does the Company believe that the 400 kW of exported power will ever increase the peak demand served by the feeder? If yes, please explain the circumstances in which that would occur.

Response Provided By:
Nathan Johnson, President & Chief Executive Officer, Citizens' Electric Company of Lewisburg, PA

Date: August 25, 2025

Response:

The Company cannot provide specific answers to subparts (i) and (ii) of this question. What, if any, distribution costs incurred and/or necessary upgrades will result from the addition of generation of new generation, even with a peak output equal to or less than existing load, is unique for each customer-generator based upon their individual load characteristics, coincidence of load and generation, characteristics of surrounding customers loads and generation, and the existing construction of the distribution system supplying them.

iii. No, adding generation will not increase feeder peak demand.

ORIGINAL

CITIZENS' ELECTRIC COMPANY OF LEWISBURG, PA
DOCKET NO. R-2025-3054394

SP-V-3

Please refer to Statement No. 1R at 17, which states "Mr. Lucas' opinion that Citizens' proposal is not in accord with the traditional "billing demand" as used in distribution ratemaking (i.e., the amount that the account imports from the utility) is incorrect.

a. Please list all other instances the Company is aware of where a utility uses a measurement of billing demand in its cost of service, cost allocation, or rate design for distribution rates that is consistent with the Company's proposed Billing Demand methodology.

Response Provided By:
Howard S. Gorman, President, HSG Group
Nathan Johnson, President & Chief Executive Officer, Citizens' Electric Company of Lewisburg, PA

Date: August 25, 2025

Response:

The Company is unaware of any unbundled distribution rates that use the definition of "Billing Demand" proposed in this case; however, the proposal is consistent with traditional cost of service principles and reflects the evolving bi-directional use of the distribution system.

ORIGINAL

CITIZENS' ELECTRIC COMPANY OF LEWISBURG, PA
DOCKET NO. R-2025-3054394

SP-V-4

Please refer to Statement No. 1R at 17-18, which states "Having fewer customers paying for the system means that more of the costs would be borne by customers that do not adopt the new technologies. The Company must continue to build, operate and maintain the system to accommodate the technology adopters. The costs to do so will not decrease; however, if the technology-adopters are able to avoid all or some of their cost responsibility, the larger cost burden would be paid by the remaining (non-technology adopting) customers."

a. Suppose that a customer with a 400 kW peak demand performs an energy efficiency upgrade that permanently reduces their peak demand to 300 kW.

    i. Confirm that the revenue collected from this customer will be reduced as a result of their lower peak demand. If deny, please explain.

    ii. Does the Company believe that this revenue reduction causes a cost-shift to other customers who have not performed energy efficiency upgrades?

b. Suppose that a customer with a 400 kW peak demand participates in a demand response program that permanently peak reduces their demand to 300 kW.

    i. Confirm that the revenue collected from this customer will be reduced as a result of their lower peak demand. If deny, please explain.

    ii. Does the Company believe that this revenue reduction causes a cost-shift to other customers who do not participate in demand response programs?

c. Suppose that a customer with a 400 kW peak demand installs a battery storage system that permanently reduces their peak demand to 300 kW.

    i. Confirm that the revenue collected from this customer will be reduced as a result of their lower peak demand. If deny, please explain.

    ii. Does the Company believe that this revenue reduction causes a cost-shift to other customers who do not install battery storage systems?

d. In any of the instances above, does the Company either currently or propose to modify its cost allocation process, its Billing Demand definitions, or its rate design methodology to

address the reduction in peak demand from the actions of these customers? If so, please explain in detail.

Response Provided By:
Nathan Johnson, President & Chief Executive Officer, Citizens' Electric Company of Lewisburg, PA

Date: August 25, 2025

Response:

a.i.
Yes, over time; however, the revenue reduction may be delayed due to the operation of the billing demand provisions in GLP-1 and GLP-3.

a.ii.
Yes. The majority of the costs for the distribution system are fixed and do not vary with usage. If all other factors are held constant, then in the next distribution rate case, distribution system costs will be shifted to other customer classes due to the lower GLP-1 or GLP-3 class demand that results from the energy efficiency upgrade. Depending on the length of historic demand and usage used for the cost of service analysis, this may take a series of rate cases. In addition, this will reduce the billing determinants used to calculate the demand and kWh-based distribution charges for GLP-1 or GLP-3, which will increase the rates and shift costs to other customers in the class.

b.i. & ii.
The Company is unaware of a demand response program that permanently reduces demand and therefore cannot answer this question. Demand response programs change the customer's consumption in response to certain conditions, such as PJM emergency conditions.

c.i.
Yes, over time; however, the revenue reduction may be delayed due to the operation of the billing demand provisions in GLP-1 and GLP-3.

c.ii.
Yes. The majority of the costs for the distribution system are fixed and do not vary with usage. If all other factors are held constant, then in the next distribution rate case, distribution system costs will be shifted to other customer classes due to the lower GLP-1 or GLP-3 class demand that results from the energy efficiency upgrade. Depending on the length of historic demand

and usage used for the cost of service analysis, this may take a series of rate cases. In addition, this will reduce the billing determinants used to calculate the demand and kWh-based distribution charges for GLP-1 or GLP-3, which will increase the rates and shift costs to other customers in the class.

d.

As previously mentioned, the billing demand provisions in GLP-1 and GLP-3 would address some of these situations by ensuring that the Billing Demand is not less than 50% of the highest Billing Demand in the last 11 months. If these situations were to occur, it would impact future cost allocations in the cost of service study. The Company is proposing in this case to increase the customer charges for GLP-1 and GLP-3, which makes recovery less dependent on the kW billing determinant. In addition, the Company may make adjustments to rate designs, cost allocations and other tariff definitions, as appropriate, in future proceedings.

ORIGINAL

CITIZENS' ELECTRIC COMPANY OF LEWISBURG, PA
DOCKET NO. R-2025-3054394

SP-V-5

Please refer to Statement No. 1R at 19, which states "For customers who use the distribution system solely to withdraw power, it is not practical to compute the potential maximum they could withdraw, and likely not meaningful; first, customers can add machines or appliances at any time; and second, it is unlikely that all machines or appliances would be used at once. For generators, though, the maximum potential use of the distribution system is knowable, and it is reasonable to expect the generator will use all its capacity at some time; after all, that is why it is there."

a. Confirm that it is readily possible for the Company to calculate the potential maximum power a customer could draw by multiplying the amperage of their service connection by the voltage they are served on. For instance, a customer who is served on a 100 amp connection at 240 volts could draw a maximum of 24 kW. If deny, please explain.

b. Please indicate any and all instances where consideration of how a customer intends to use electricity and any measures of the "reasonableness" of that usage, and not their actual use of the system, is determinative in cost allocation or rate design.

Response Provided By:
Nathan Johnson, President & Chief Executive Officer, Citizens' Electric Company of Lewisburg, PA

Date: August 5, 2025

Response:

(a) Denied, due to National Electrical Code ("NEC") requirements for commercial services, the size of a customer's service is often substantially larger than any realistic determination of the actual load present behind the service. In practice the company sizes its facilities for consumption-only accounts based on determinations of the maximum possible diversified consumption behind the meter. Customers are required to inform the Company if their maximum possible consumption increases so that the service can be resized (and their bill may increase as well). The NEC does not require customer-generators to overstate their gross generator capacity. In the case of solar, the customer generator sizes their inverters—which determine gross generator capacity—at their discretion. Additionally, they may add additional generation behind the inverters—up to the gross generator capacity—without further notification to the utility, because they have already been approved to interconnect at that level of potential export.

(b) Citizens' current tariff includes a provision that allows volunteer fire departments, non-profit ambulance services, non-profit rescue squads and non-profit senior citizens centers to be billed under the residential rate schedule. GLP-1 and GLP-3 also set a minimum billing demand using 50% of the highest demand during the prior 11 months. Other examples may exist; however, identifying "any and all instances" would require an unreasonable study and excessive burden when the Company can already identify these examples in its tariff.

ORIGINAL

EXHIBIT KL-13

ORIGINAL

CITIZENS' ELECTRIC COMPANY OF LEWISBURG, PA
DOCKET NO. R-2025-3054394

SP-IV-6

Please state whether the Company has conducted any cost-of-service study comparing the cost responsibility of customer-generators under (a) actual metered peak inflow/outflow demand and (b) GGR-based billing demand. If so, provide the date, authors, and conclusions.

Response Provided By:
Nathan Johnson, President & Chief Executive Officer, Citizens' Electric Company of Lewisburg, PA

Date: August 25, 2025

Response:

The Company has not conducted a rate analysis directly comparing the demand quantities listed above. At this time, the Company does not have the metering capability to measure bi-directional demand.

ORIGINAL

EXHIBIT KL-14

ORIGINAL

CITIZENS' ELECTRIC COMPANY OF LEWISBURG, PA
DOCKET NO. R-2025-3054394

SP-IV-23

Please confirm that the Company has not conducted a cost-of-service study isolating the marginal cost of exports from distributed generation.

Response Provided By:
Nathan Johnson, President & Chief Executive Officer, Citizens' Electric Company of Lewisburg, PA

Date: August 25, 2025

Response:

Confirmed, the Company does not conduct marginal cost studies.

ORIGINAL

EXHIBIT KL-15

ORIGINAL

CITIZENS' ELECTRIC COMPANY OF LEWISBURG, PA
DOCKET NO. R-2025-3054394

SP-V-3

Please refer to Statement No. 1R at 17, which states "Mr. Lucas' opinion that Citizens' proposal is not in accord with the traditional "billing demand" as used in distribution ratemaking (i.e., the amount that the account imports from the utility) is incorrect.

a. Please list all other instances the Company is aware of where a utility uses a measurement of billing demand in its cost of service, cost allocation, or rate design for distribution rates that is consistent with the Company's proposed Billing Demand methodology.

Response Provided By:
Howard S. Gorman, President, HSG Group
Nathan Johnson, President & Chief Executive Officer, Citizens' Electric Company of Lewisburg, PA

Date: August 25, 2025

Response:

The Company is unaware of any unbundled distribution rates that use the definition of "Billing Demand" proposed in this case; however, the proposal is consistent with traditional cost of service principles and reflects the evolving bi-directional use of the distribution system.

ORIGINAL

EXHIBIT KL-16

ORIGINAL

CITIZENS' ELECTRIC COMPANY OF LEWISBURG, PA
DOCKET NO. R-2025-3054394

SP-III-1

Please refer to the Company's response to SP-II-3, which states "The most obvious example of instability caused by DER is intermittent cloud cover over solar arrays. A cloud bank passing over a group of large distribution arrays can cause a significant change in power flow over a very short time period, causing a voltage sag. This causes voltage control devices on the system to react to restore voltage, but may then result in a subsequent voltage surge as the clouds pass and SPV output returns to its full potential. Aside from the immediate concern of voltage instability, this increases the duty cycle of voltage control devices, which shortens their expected lifespans. It may also negatively impact nearby consumers."

a. Confirm whether the voltage control devices referred to above are manually adjusted, actively adjusted, or function passively. To the extent there are different types of voltage control devices being referred to in the response, please expand how each type would respond to the event discussed above.
b. On what time frame (sub-second, second, minutes, etc.) do the voltage control devices operate to correct system voltage?
c. Please confirm that the Company's interconnection process screens for the types of voltage instability discussed above. If denied, please explain.
d. If c) above is confirmed, will the Company allow a DER to connect to its grid without requiring customer-generator-funded system upgrades? Please explain the process in detail.
e. Suppose the Company has a commercial customer with a 400 kW load, 200 kW of which can rapidly switch on and off.
    i. Confirm that the customer's rapidly changing load can cause a significant change in power flow on the Company's system over a short time period. If denied, please explain in detail why.
    ii. Confirm that the customer's rapidly changing load can impact voltage on the Company's system. If denied, please explain in detail why.
    iii. Confirm that voltage control systems on the Company's grid will react to restore voltage as this customer's load changes rapidly. If denied, please explain in detail why.
    iv. Please explain all differences in the impact on the grid of a PV system that sees a 200 kW reduction in power output over 10 seconds from a passing cloud and a customer with a large load activating 200 kW of load over 10 seconds.

Response Provided By:
Nathan Johnson, President & Chief Executive Officer, Citizens' Electric Company

Date: July 14, 2025

Response:

a. The voltage control devices referred to are automated devices that respond to deviations from programmed time-voltage criteria to correct system voltage. The Company uses both automatically controlled capacitor banks and regulators. The Company does utilize 'fixed' and manually energy capacitors, but neither are relevant to the circumstances referred to in this question and response.

b. Typical voltage control devices on the Company's system use two levels of criteria. Under both criteria, devices can react to changes in system voltage within seconds. More importantly, to provide for stability and prevent 'hunting' (a phenomenon where nearby devices react to each other, rather than system-driven changes), devices have a time delay between operations and may also use a longer time delay if more than a pre-determined number of operations occur within a set period. Devices also have 'override' criteria to prevent system voltages from deviating out of a wider, pre-determined bandwidth. Override criteria has fewer limitations on the interval and number of operations.

c. Confirmed, the company screens for the potential incremental system impact of each interconnection.

d. Customers are required to fund system upgrades to mitigate potential disruption or instability caused by their interconnection. The Company's system modelling software allows it to model proposed interconnections and evaluate their effect on system conditions, including voltage. If disruptions can be handled by the Company's existing equipment, then no upgrade funding will be required prior to interconnection. If unacceptable effects are indicated, mitigating upgrades can be modeled and tested for effectiveness to identify the most practical and economical solution. Once a solution is identified, a magnitude estimate for the upgrade is developed and provided to the customer for them to determine if they wish to proceed with the interconnection as planned, discuss potential modifications with engineering to lessen costs, or abandon the application.

e. Regarding a customer with 200kW of rapidly fluctuating load:

   i. Denied, a rapidly shifting 200kW load may cause some 'hyper-local' changes in power flow, but a 200kW shift in load is unlikely to affect power flow on a system scale.

   ii. Denied, similar to subpart (i), a rapidly shifting 200kW load may cause some 'hyper-local' voltage impacts, affecting customers in their immediate area. Once this impact was identified, the customer would be required to make changes to mitigate these effects.

   iii. Confirmed, if a change in customer load causes a voltage disruption of sufficient magnitude to affect system voltage, installed voltage control devices will react to

stabilize voltage. As noted above, the customer may be required to make changes to mitigate ongoing voltage disruptions.

iv. There is little difference in system impact between a rapid change in a 200kW customer load and 200kW of PV generation; both situations may require corrective actions by the account and/or the operation of on-system control devices.

ORIGINAL

CITIZENS' ELECTRIC COMPANY OF LEWISBURG, PA
DOCKET NO. R-2025-3054394

SP-III-2

Please refer to workpaper SP-II-5 Attachment A

a. There is a note that the 6/1/25 GSSR Rates are used. How often are these rates updated?
b. What time period does the 6/1/25 GSSR rate represent?
c. Do the PTC components listed in rows 2-8 of the first three tabs represent prices at the generator level, or prices at the meter level?
d. What is the source for the 3.2% loss factor, and what loss factor does this represent?
e. There is a note in row 31 that states "PJM costs substantially unaffected by net metered sales."
    i. What is the basis for this statement?
    ii. Please provide all workpapers that were developed to support this statement in their original format with formulas intact.
    iii. Confirm that in the Company's workpaper, energy purchased through net metered export is provided zero value in reducing PJM costs paid, as indicated by the same values being found in cells C31 as in cells C20. If denied, please explain in detail why.
f. On tab "Ex + Prop >400kW", the value for MWh purchased from Supplier is 1,880 MWh, with a note that says, "Expected annual overproduction of existing & proposed >400kW NM Generation."
    i. What is the basis of this assumed annual overproduction?
    ii. Please provide all workpapers that were used to develop the 1,880 MWh value in their original format with formulas intact.
g. On tab "PVWatts 400kWAC Analysis", it appears the Company used a 440 kW DC size with a 1.2 DC/AC inverter load rating. If the intent was to produce a 400 kW AC system, why were these values used?
h. On tab "PVWatts 3MWAC Analysis",
    i. It appears the Company used a 3,300 kW DC size with a 1.2 DC/AC inverter load rating. If the intent was to produce a 3,000 kW AC system, why were these values used?
    ii. Is it the Company's position that 3 MW single axis tracking systems typically have an inverter load rating of 1.1 or 1.2? If so, please provide the basis for this position.
i. Confirm that if a behind-the-meter DER generates 400 kW in a given hour, that the impact on the Company's aggregate load that must be met by a wholesale supplier in that hour is the same whether the energy is consumed onsite by the customer-generator or exported to the nearest source of load, excluding any losses between the customer-generator and the nearest source of load. If deny, please explain in full.

Response Provided By:
Nathan Johnson, President & Chief Executive Officer, Citizens' Electric Company

Date: July 14, 2025

Response:

a. GSSR Rates are typically updated on June 1 and December 1 each year. Interim GSSR changes may be filed if changes occur in the projected purchased power costs that would result in a significant over or under collection if the GSSR Rates are not updated.
b. The 6/1/25 GSSR rate is expected to remain in effect from June 1, 2025 through November 30, 2025.
c. The Price-to-Compare (PTC) is a cost published by the Company that represents the current cost of default supply service at the meter, inclusive of gross receipts tax (GRT), State Tax Adjustment Surcharge (STAS), and other governmental or regulatory mandated taxes and fees, and not including Sales Tax.
d. As stated in the Citizens' tariff, the loss factor is adjusted each June 1 to reflect the rolling three calendar year average of distribution losses on the system. It is the difference between metered energy delivered to the substation and aggregated metered energy delivered to customers over the calculation period.
e. Regarding "PJM costs substantially unaffected by net metered sales," the Company is referring to the sum of PJM Capacity, Transmission, and RTEP costs:
    i. As demonstrated in SP-II-5 Attachment A, the Company has analyzed the past ten years of PJM peak hours and found that:
        1. On average, fixed rooftop PV systems are able to provide approximately 21% of their rated output for NSPL hours and 25% of rated output for PLC hours. Ground mounted, tracking systems can be expected to provide 27% and 40% of their rated output for NSPL and PLC hours, respectively.

        2. Both system types show significant volatility in their ability to contribute during peak times, ranging from 0% to 80% of rated output, with little ability to predict or anticipate coincidence in advance. It should be noted that the analysis does not account for additional volatility caused by localized environmental conditions (e.g. cloud cover), customer-generator load and demand response, and generator availability (i.e. is the generator online at all).

    Additionally, the Company cannot dispatch net-metered generation, nor are net-metered customer-generators obligated to produce or export during peak hours.

    ii. The Company's workpapers to support this conclusion are those provided as attachments to the revised response to SP-II-5.

    iii. Confirmed, the Company's calculation does not assume a reduction in PJM costs based on increases in net metered exports, nor does it assign any credit to net metered generation in its calculations based on a single or aggregated customers' performance during the peaks that determine the billing determinants for the PJM costs. As stated in subpart (i), over ten years, an average of only 25% of the rated output of net metered generation is expected to be available during peak hours. There is also high volatility in coincidence between net-metered generation export and PJM peak hours. Additionally, the Company must treat net-metered customer-

generators similar to non-generating customers in the same rate classes. Non-generating GSSR-1 customers are not individually credited for any actions that they take that might mitigate PJM costs. GSSR-2 customers are charged for PJM generation, transmission, and RTEP costs based on their calculated individual contribution to PJM peaks, but are not further credited for any benefit their demand response might provide to other GSSR-2 customers.

f. Regarding the 'Ex + Prop >400kW' tab:

i. The estimated annual overproduction is based on historical actual overproduction by existing net metered customers, plus estimated overproduction by >400kW interconnection applications in the queue with sufficient known data to determine overproduction estimates.

ii. Workpapers were not used to develop the 1,880MWh estimated export of customer-generators with rated outputs exceeding 400kW, as only three active or proposed installations meet this criteria. The table below provides the data used to calculate the estimated export:

SL	Status	Actual Export (2025)	Expected Export (ICA)
18167	Active	112,171 kWh	
	Proposed		835,000 kWh
	Proposed		933,000 kWh
TOTAL:		**1,880,171 kWh**	

g. The 1.2 DC to AC ratio is the PVWatts default assumption, the Company used a 1.1 factor, in error, to set total DC system size. The Company has revised the attachments to SP-II-5 and will resubmit them as a revised to response to SP-II-5.

h. Regarding the 3MWAC PVWatts Analysis:

i. See the Company's response to subpart (g), above.

ii. The Company's analysis utilizes standard PVWatts assumptions in its analysis in order to provide an objective 3rd party source of data without unnecessary modification by the Company. The Company has found that PVWatts analysis of customer interconnection applications tends to closely match estimated production provided in the application, and thus trusts that these values are an accurate representation of actual output. Any debate as the reasonableness of the DC to AC ratio used is, in fact, irrelevant to the Company's analysis, as the Company used the ratio only to provide the necessary DC system size to achieve the rated AC outputs desired for analysis. No DC values are used for the analysis. This is reflective of the Company's handling of actual net-metered interconnections, where

the AC rated output capacity, and AC production and export are used for modeling, analysis, and crediting of net-metered generation.

i. Confirmed if the customer generator is a default service customer. The customer generator has the option to deal with an Electric Generation Supplier for its supply arrangements.

ORIGINAL

CITIZENS' ELECTRIC COMPANY OF LEWISBURG, PA
DOCKET NO. R-2025-3054394

SP-III-3

Please refer to workpaper SP-II-5 Attachment B.

a. On tab "Coincidence Analysis", please provide the source for the values date and time values in column B and G for PLC and NSPL, respectively.

b. The formula that calculates the "% Nameplate Production on PLC" and "% Nameplate Production on NSPL" divide the system size by 1.1. Please indicate the purpose of this adjustment.

Response Provided By:
Nathan Johnson, President & Chief Executive Officer, Citizens' Electric Company

Date: July 14, 2025

Response:

a. Columns B and G are the PJM peak hours provided to the Company annually and used in determining GSSR-1 and individual GSSR-2 customer contributions to peak costs.

b. See the Company's response to SP-III-2 (g), the Company used a 1.1 factor to determine AC rated output in error. The intent of the adjustment was to convert the DC system size in the PVWatts tabs to AC system size for use in the coincidence analysis.

ORIGINAL

EXHIBIT KL-17

ORIGINAL

CITIZENS' ELECTRIC COMPANY OF LEWISBURG, PA
DOCKET NO. R-2025-3054394

SP-II-5

Please reference Citizens' St. No. 4, p. 17. Has Citizens conducted any studies or analyses of the effects of this tariff change on Citizens' default procurement of electricity based on its Default Service Plan ("DSP")? If yes, please provide all studies or analyses related to the same.

Response Provided By:
Nathan Johnson, President & CEO

Date: June 30, 2025 (original)
July 14, 2025 (revised)

Response:

July 14, 2025 Revisions:
The Company has revised the attachments ("SP-II-5 Attachment A" and "SP-II-5 Attachment B") provided with the original response to SP-II-5, and made revisions to the response below, highlighted in yellow after identifying a data error related to the AC-to-DC ratio of the model PV systems used.

Original Response with July 14, 2025 Revision Incorporated:

Yes, the Company has analyzed the impact of net metered energy on default service costs in two different ways:

1) The direct cost of purchased net-metered energy compared to the cost of purchasing the same volume of energy through the DSP.

2) The potential for net-metered generation to mitigate PJM Capacity, Transmission, and RTEP costs.

The purchase cost analysis can be found in the attachment titled "SP-II-5 Attachment A (REV)." It contains several comparisons, summarized in the table below:

Comparison	Description	Result
400kW	400kW$_{AC}$ Roof Mount SPV w/ no offset load, standard PVWatts® roof-mount parameters	~$27,000 increase in GSSR-1 costs annually.
Ex + Prop >400kW	Expected net-metered export purchases of existing and proposed systems with ≥400kW rated output capacity	~$88,000 increase in GSSR-1 costs annually.

3000kW	3MW$_{AC}$ Rack Mounted Tracking (w/ Backtracking) SPV, premium panels, standard PVWatts® parameters	~$230,000 increase in GSSR-1 costs annually.

The analysis of PJM cost mitigation can be found in the attachment titled "SP-II-5 Attachment B (REV)." It contains a ten year history of PJM Capacity and Transmission peak hours and hourly outputs from the same PVWatts® studies used in Attachment A (REV). For nearly half of the past decade's PJM Capacity and Transmission Peak hours, SPV output from either model was 20% or less of rated capacity, demonstrating the limited ability of net-metered SPV to mitigate PJM costs.

Additionally, while no quantitative analysis has been performed, basic market principles suggest that as the total volume of energy purchased decreases, the price-per-unit will increase. In essence, as more energy is purchased from net-metered exports, less is purchased through the DSP wholesale contract. This lowers the 'buying power' of the DSP while concentrating non-volumetric (Company and supplier admin costs, Capacity, Transmission, and RTEP) costs across a smaller total quantity purchased, increasing the cost per MWh of default supply.

Finally, as purchased net-metered energy creates net under collection of GSSR costs under the existing structure (where the customer generator receives the GSSR-1 price regardless of the generator's size), the resulting reconciliation in future periods through the E-factor inflates the cost of default supply which, in turn, inflates the purchased cost of future-period net-metered energy purchases. In short, net-metered customer-generators directly benefit from the price inflation that they cause in a compounding fashion that increases as more net-metered generation is installed.

The Company concludes from its analysis that 1) net-metered generation exports result in a significant increase to default supply costs and 2) its proposed tariff change will mitigate these increases by shifting large exporters to the GSSR-2 rate and corresponding reimbursement formula.

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EXHIBIT KL-18

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Coincidence Analysis

Original Company Analysis

SP-II-5 ATTACHMENT B (REV)

	PLC				NSPL				400kW Roof SPV		3MW Tracking SPV		Sorted			
	Hour Beginning	Mo	Day	Hr	Hour Beginning	Mo	Day	Hr	% Nameplate Production on PLC	% Nameplate Production on NSPL	% Nameplate Production on PLC	% Nameplate Production on NSPL				
2015	7/28/2015 16:00	7	28	16	1/8/2015 7:00	1	8	7	8.93%	0.00%	7.05%	0.00%	0.00%	0.00%	0.00%	0.00%
	7/20/2015 16:00	7	20	16	2/16/2015 8:00	2	16	8	24.77%	0.60%	29.27%	0.49%	0.50%	0.00%	0.46%	0.00%
	7/29/2015 16:00	7	29	16	2/19/2015 19:00	2	19	19	29.75%	0.00%	40.54%	0.00%	0.50%	0.00%	0.46%	0.00%
	9/3/2015 16:00	9	3	16	2/20/2015 8:00	2	20	8	27.07%	21.85%	47.63%	30.00%	1.32%	0.00%	1.76%	0.00%
	8/17/2015 14:00	8	17	14	2/24/2015 7:00	2	24	7	57.22%	5.57%	62.59%	6.62%	8.04%	0.00%	6.75%	0.00%
2016	7/25/2016 15:00	7	25	15	1/19/2016 7:00	1	19	7	59.58%	0.00%	80.74%	0.00%	8.10%	0.00%	6.75%	0.00%
	7/27/2016 16:00	7	27	16	7/14/2016 16:00	7	14	16	32.42%	27.36%	47.93%	34.99%	8.10%	0.00%	6.84%	0.00%
	8/10/2016 16:00	8	10	16	7/25/2016 13:00	7	25	13	37.56%	78.36%	66.54%	80.90%	8.24%	0.00%	7.03%	0.00%
	8/11/2016 15:00	8	11	15	8/11/2016 14:00	8	11	14	58.99%	71.28%	80.86%	81.03%	8.93%	0.00%	7.05%	0.00%
	8/12/2016 15:00	8	12	15	9/8/2016 16:00	9	8	16	55.04%	31.22%	75.46%	63.41%	8.93%	0.00%	7.05%	0.00%
2017	6/12/2017 17:00	6	12	17	12/15/2016 18:00	12	15	18	14.83%	0.00%	23.67%	0.00%	9.84%	0.00%	8.52%	0.00%
	6/13/2017 16:00	6	13	16	12/16/2016 7:00	12	16	7	8.93%	0.00%	7.05%	0.00%	10.46%	0.00%	9.87%	0.00%
	7/19/2017 17:00	7	19	17	12/20/2016 7:00	12	20	7	8.10%	0.00%	6.75%	0.00%	10.73%	0.00%	17.29%	0.00%
	7/20/2017 16:00	7	20	16	1/9/2017 8:00	1	9	8	24.77%	8.43%	29.27%	8.37%	11.42%	0.00%	22.68%	0.00%
	7/21/2017 16:00	7	21	16	1/10/2017 7:00	1	10	7	38.86%	0.00%	62.30%	0.00%	13.38%	0.00%	23.67%	0.00%
2018	8/28/2018 17:00	8	28	17	1/3/2018 7:00	1	3	7	0.50%	0.00%	0.46%	0.00%	14.35%	0.00%	28.23%	0.00%
	9/4/2018 17:00	9	4	17	1/4/2018 19:00	1	4	19	11.42%	0.00%	32.39%	0.00%	14.83%	0.00%	29.27%	0.00%
	6/18/2018 17:00	6	18	17	1/5/2018 17:00	1	5	17	9.84%	0.00%	8.52%	0.00%	14.95%	0.31%	29.27%	0.31%
	9/5/2018 17:00	9	5	17	7/2/2018 16:00	7	2	16	10.73%	34.82%	28.23%	52.47%	16.30%	0.60%	29.27%	0.49%
	8/27/2018 17:00	8	27	17	8/29/2018 16:00	8	29	16	1.32%	36.86%	1.76%	71.31%	17.93%	1.74%	29.82%	1.67%
2019	7/10/2019 17:00	7	10	17	1/22/2019 7:00	1	22	7	0.00%	0.00%	0.00%	0.00%	19.03%	2.27%	31.98%	1.67%
	7/17/2019 16:00	7	17	16	1/30/2019 18:00	1	30	18	44.37%	0.00%	76.72%	0.00%	19.04%	3.91%	32.39%	2.95%
	7/19/2019 17:00	7	19	17	1/31/2019 7:00	1	31	7	8.10%	0.31%	6.75%	0.31%	20.28%	5.57%	35.91%	6.62%
	7/29/2019 16:00	7	29	16	2/1/2019 7:00	2	1	7	29.75%	0.00%	40.54%	0.00%	21.87%	8.04%	38.71%	7.03%
	8/19/2019 16:00	8	19	16	7/19/2019 16:00	7	19	16	36.97%	2.27%	68.40%	1.67%	23.53%	8.43%	40.54%	8.37%
2020	7/6/2020 14:00	7	6	14	7/20/2020 17:00	7	20	17	56.55%	10.46%	61.60%	9.87%	24.77%	10.46%	40.54%	9.87%
	7/9/2020 17:00	7	9	17	7/22/2020 14:00	7	22	14	8.24%	64.59%	6.84%	72.82%	24.77%	10.73%	44.40%	12.15%
	7/20/2020 16:00	7	20	16	7/27/2020 17:00	7	27	17	24.77%	8.04%	29.27%	7.03%	24.77%	11.96%	46.30%	17.29%
	7/27/2020 16:00	7	27	16	8/10/2020 17:00	8	10	17	32.42%	19.06%	47.93%	53.89%	25.42%	13.38%	47.63%	28.23%
	7/29/2020 17:00	7	29	17	8/11/2020 14:00	8	11	14	16.30%	71.28%	31.98%	81.03%	27.07%	19.06%	47.93%	30.00%
2021	6/29/2021 16:00	6	29	16	6/28/2021 17:00	6	28	17	42.61%	11.96%	74.09%	12.15%	29.75%	21.85%	47.93%	33.37%
	7/6/2021 16:00	7	6	16	6/29/2021 17:00	6	29	17	25.42%	3.91%	29.82%	2.95%	29.75%	27.36%	49.53%	34.99%
	8/12/2021 16:00	8	12	16	6/30/2021 15:00	6	30	15	38.67%	54.94%	69.83%	72.91%	31.22%	27.38%	55.18%	35.00%
	8/24/2021 17:00	8	24	17	8/12/2021 14:00	8	12	14	14.95%	66.75%	38.71%	75.74%	32.42%	28.30%	59.51%	36.08%
	8/26/2021 15:00	8	26	15	8/26/2021 16:00	8	26	16	49.49%	36.72%	66.39%	69.41%	32.42%	31.22%	60.66%	49.38%
2022	7/20/2022 17:00	7	20	17	1/27/2022 7:00	1	27	7	10.46%	0.00%	9.87%	0.00%	33.56%	34.82%	61.60%	52.47%
	7/21/2022 16:00	7	21	16	1/31/2022 8:00	1	31	8	38.86%	28.30%	62.30%	36.08%	36.97%	35.22%	62.30%	53.89%
	7/22/2022 17:00	7	22	17	8/4/2022 14:00	8	4	14	20.28%	46.50%	44.40%	49.38%	37.56%	36.72%	62.30%	57.33%
	8/3/2022 17:00	8	3	17	8/8/2022 16:00	8	8	16	19.03%	37.44%	46.30%	64.49%	38.67%	36.86%	62.59%	63.41%
	8/8/2022 15:00	8	8	15	8/9/2022 14:00	8	9	14	46.83%	61.80%	60.66%	68.97%	38.86%	37.44%	66.39%	64.49%
2023	7/5/2023 17:00	7	5	17	12/23/2022 18:00	12	23	18	23.53%	0.00%	66.69%	0.00%	38.86%	46.50%	66.54%	68.97%
	7/27/2023 17:00	7	27	17	2/3/2023 19:00	2	3	19	8.04%	0.00%	7.03%	0.00%	42.61%	47.25%	66.69%	69.41%
	7/28/2023 17:00	7	28	17	9/5/2023 17:00	9	5	17	14.35%	10.73%	22.68%	28.23%	44.37%	54.94%	67.09%	71.31%
	9/5/2023 16:00	9	5	16	9/6/2023 18:00	9	6	18	33.56%	0.00%	67.09%	0.00%	46.83%	61.80%	68.40%	72.82%
	9/6/2023 16:00	9	6	16	9/7/2023 13:00	9	7	13	31.22%	35.22%	59.51%	33.37%	49.49%	64.59%	69.83%	72.91%
2024	6/21/2024 17:00	6	21	17	1/17/2024 8:00	1	17	8	21.87%	1.74%	55.18%	1.67%	55.04%	66.75%	74.09%	75.74%
	7/15/2024 17:00	7	15	17	7/9/2024 14:00	7	9	14	13.38%	69.82%	17.29%	80.51%	56.55%	69.82%	75.46%	80.51%
	7/16/2024 17:00	7	16	17	7/10/2024 16:00	7	10	16	17.93%	27.38%	35.91%	35.00%	57.22%	71.28%	76.72%	80.90%
	8/1/2024 17:00	8	1	17	7/15/2024 17:00	7	15	17	19.04%	13.38%	49.53%	17.29%	58.99%	71.28%	80.74%	81.03%
	8/28/2024 17:00	8	28	17	7/16/2024 15:00	7	16	15	0.50%	47.25%	0.46%	57.33%	59.58%	78.36%	80.86%	81.03%

Average Output on Peak	25.36%	20.92%	39.85%	27.23%
Max Output on Peak	59.58%	78.36%	80.86%	81.03%
Min Output on Peak	0.00%	0.00%	0.00%	0.00%
# <10%	11	25	12	26
# 10-20%	11	5	1	2
# 20-30%	10	4	7	1
# 30-40%	9	6	4	5
# 40-50%	4	2	8	1
# 50-60%	5	1	2	3
# 60-70%	0	4	11	4
# 70-80%	0	3	3	4
# 80-90%	0	0	2	4
# 90-100%	0	0	0	0
# >100 %	0	0	0	0

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Coincidence Analysis - EPT Fix

Original Company Analysis with DST Fix

SP-II-5 ATTACHMENT B (REV)

	PLC				NSPL				400kW Roof SPV		3MW Tracking SPV		Sorted			
	Hour Beginning	Mo	Day	Hr	Hour Beginning	Mo	Day	Hr	% Nameplate Production on PLC	% Nameplate Production on NSPL	% Nameplate Production on PLC	% Nameplate Production on NSPL				
2015	7/28/2015 16:00	7	28	15	1/8/2015 7:00	1	8	7	26.71%	0.00%	25.86%	0.00%	2.27%	0.00%	1.67%	0.00%
	7/20/2015 16:00	7	20	15	2/16/2015 8:00	2	16	8	55.81%	0.60%	73.80%	0.49%	2.27%	0.00%	1.67%	0.00%
	7/29/2015 16:00	7	29	15	2/19/2015 19:00	2	19	19	39.16%	0.00%	43.95%	0.00%	3.80%	0.00%	2.88%	0.00%
	9/3/2015 16:00	9	3	15	2/20/2015 8:00	2	20	8	11.62%	21.85%	9.80%	30.00%	7.64%	0.00%	5.91%	0.00%
	8/17/2015 14:00	8	17	13	2/24/2015 7:00	2	24	7	71.70%	5.57%	71.63%	6.62%	7.78%	0.00%	6.26%	0.00%
	7/25/2016 15:00	7	25	14	1/19/2016 7:00	1	19	7	70.79%	0.00%	81.01%	0.00%	7.78%	0.00%	6.26%	0.00%
2016	7/27/2016 16:00	7	27	15	7/14/2016 16:00	7	14	15	50.95%	37.38%	65.91%	41.18%	8.93%	0.00%	7.05%	0.00%
	8/10/2016 16:00	8	10	15	7/25/2016 13:00	7	25	12	57.20%	81.99%	78.14%	80.85%	11.62%	0.00%	9.80%	0.00%
	8/11/2016 15:00	8	11	14	8/11/2016 14:00	8	11	13	71.28%	76.25%	81.03%	76.86%	15.65%	0.00%	13.94%	0.00%
	8/12/2016 15:00	8	12	14	9/8/2016 16:00	9	8	15	66.75%	50.42%	75.74%	71.95%	18.79%	0.00%	17.98%	0.00%
	6/12/2017 17:00	6	12	16	12/15/2016 18:00	12	15	18	41.74%	0.00%	74.26%	0.00%	20.70%	0.00%	19.36%	0.00%
2017	6/13/2017 16:00	6	13	15	12/16/2016 7:00	12	16	7	7.64%	0.00%	5.91%	0.00%	24.49%	0.00%	25.86%	0.00%
	7/19/2017 17:00	7	19	16	12/20/2016 7:00	12	20	7	2.27%	0.00%	1.67%	0.00%	24.77%	0.00%	29.27%	0.00%
	7/20/2017 16:00	7	20	15	1/9/2017 8:00	1	9	8	55.81%	8.43%	73.80%	8.37%	26.71%	0.00%	33.15%	0.00%
	7/21/2017 16:00	7	21	15	1/10/2017 7:00	1	10	7	53.56%	0.00%	69.45%	0.00%	27.38%	0.00%	35.00%	0.00%
	8/28/2018 17:00	8	28	16	1/3/2018 7:00	1	3	7	7.78%	0.00%	6.26%	0.00%	28.74%	0.00%	37.23%	0.00%
2018	9/4/2018 17:00	9	4	16	1/4/2018 19:00	1	4	19	35.07%	0.00%	70.79%	0.00%	29.75%	0.31%	40.54%	0.31%
	6/18/2018 17:00	6	18	16	1/5/2018 17:00	1	5	17	38.43%	0.00%	62.86%	0.00%	31.69%	0.60%	42.55%	0.49%
	9/5/2018 17:00	9	5	16	7/2/2018 16:00	7	2	15	33.56%	48.49%	67.09%	61.36%	32.42%	1.74%	43.95%	1.54%
	8/27/2018 17:00	8	27	16	8/29/2018 16:00	8	29	15	3.80%	44.64%	2.88%	59.38%	33.56%	2.11%	43.95%	1.67%
	7/10/2019 17:00	7	10	16	1/22/2019 7:00	1	22	7	27.38%	0.00%	35.00%	0.00%	34.21%	5.57%	47.93%	6.62%
2019	7/17/2019 16:00	7	17	15	1/30/2019 18:00	1	30	18	60.48%	0.00%	82.21%	0.00%	35.07%	7.45%	50.38%	8.37%
	7/19/2019 17:00	7	19	16	1/31/2019 7:00	1	31	7	2.27%	0.31%	1.67%	0.31%	38.43%	8.43%	52.35%	13.94%
	7/29/2019 16:00	7	29	15	2/1/2019 7:00	2	1	7	39.16%	0.00%	43.95%	0.00%	38.49%	15.65%	61.21%	14.00%
	8/19/2019 16:00	8	19	15	7/19/2019 16:00	7	19	15	52.32%	43.57%	71.95%	51.66%	39.09%	21.85%	62.86%	29.27%
	7/6/2020 14:00	7	6	13	7/20/2020 17:00	7	20	16	72.26%	24.77%	74.68%	29.27%	39.16%	24.77%	65.91%	30.00%
2020	7/9/2020 17:00	7	9	16	7/22/2020 14:00	7	22	13	18.79%	62.28%	19.36%	63.09%	39.16%	28.30%	65.91%	31.58%
	7/20/2020 16:00	7	20	15	7/27/2020 17:00	7	27	16	55.81%	32.42%	73.80%	47.93%	40.80%	32.32%	66.80%	33.62%
	7/27/2020 16:00	7	27	15	8/10/2020 17:00	8	10	16	50.95%	37.56%	65.91%	66.54%	41.21%	32.42%	67.09%	36.08%
	7/29/2020 17:00	7	29	16	8/11/2020 14:00	8	11	13	29.75%	76.25%	40.54%	76.86%	41.74%	33.56%	69.45%	38.81%
	6/29/2021 16:00	6	29	15	6/28/2021 17:00	6	28	16	58.37%	2.11%	79.91%	1.54%	45.09%	33.90%	69.45%	41.18%
2021	7/6/2021 16:00	7	6	15	6/29/2021 17:00	6	29	16	20.70%	42.61%	17.98%	74.09%	50.95%	37.38%	69.47%	41.97%
	8/12/2021 16:00	8	12	15	6/30/2021 15:00	6	30	14	55.04%	54.69%	75.46%	59.45%	50.95%	37.56%	70.79%	47.93%
	8/24/2021 17:00	8	24	16	8/12/2021 14:00	8	12	13	24.49%	74.42%	37.23%	75.27%	52.32%	37.85%	71.23%	51.66%
	8/26/2021 15:00	8	26	14	8/26/2021 16:00	8	26	15	60.49%	49.49%	66.80%	66.39%	53.32%	40.72%	71.63%	59.38%
	7/20/2022 17:00	7	20	16	1/27/2022 7:00	1	27	7	24.77%	0.00%	29.27%	0.00%	53.56%	42.61%	71.95%	59.45%
2022	7/21/2022 16:00	7	21	15	1/31/2022 8:00	1	31	8	53.56%	28.30%	69.45%	36.08%	53.56%	43.57%	73.80%	60.66%
	7/22/2022 17:00	7	22	16	8/4/2022 14:00	8	4	13	38.49%	73.00%	61.21%	74.18%	55.04%	44.64%	73.80%	61.36%
	8/3/2022 17:00	8	3	16	8/8/2022 16:00	8	8	15	28.74%	46.83%	42.55%	60.66%	55.81%	46.83%	73.80%	63.09%
	8/8/2022 15:00	8	8	14	8/9/2022 14:00	8	9	13	31.69%	77.42%	33.15%	78.37%	55.81%	48.49%	74.26%	66.39%
	7/5/2023 17:00	7	5	16	12/23/2022 18:00	12	23	18	45.09%	0.00%	78.49%	0.00%	55.81%	49.49%	74.68%	66.54%
2023	7/27/2023 17:00	7	27	16	2/3/2023 19:00	2	3	19	32.42%	0.00%	47.93%	0.00%	57.20%	50.42%	75.46%	67.09%
	7/28/2023 17:00	7	28	16	9/5/2023 17:00	9	5	16	8.93%	33.56%	7.05%	67.09%	58.37%	54.69%	75.74%	71.95%
	9/5/2023 16:00	9	5	15	9/6/2023 18:00	9	6	17	53.32%	7.45%	75.78%	14.00%	60.48%	62.28%	75.78%	74.09%
	9/6/2023 16:00	9	6	15	9/7/2023 13:00	9	7	12	39.09%	40.72%	52.35%	38.81%	60.49%	73.00%	78.14%	74.18%
	6/21/2024 17:00	6	21	16	1/17/2024 8:00	1	17	8	41.21%	1.74%	69.47%	1.67%	66.75%	74.42%	78.49%	75.27%
2024	7/15/2024 17:00	7	15	16	7/9/2024 14:00	7	9	13	15.65%	33.90%	13.94%	33.62%	70.79%	76.25%	79.91%	76.86%
	7/16/2024 17:00	7	16	16	7/10/2024 16:00	7	10	15	34.21%	37.85%	50.38%	41.97%	71.28%	76.25%	81.01%	76.86%
	8/1/2024 17:00	8	1	16	7/15/2024 17:00	7	15	16	40.80%	15.65%	71.23%	13.94%	71.70%	77.42%	81.03%	78.37%
	8/28/2024 17:00	8	28	16	7/16/2024 15:00	7	16	14	7.78%	32.32%	6.26%	31.58%	72.26%	81.99%	82.21%	80.85%

Average Output on Peak	38.51%	26.10%	50.74%	30.83%
Max Output on Peak	72.26%	81.99%	82.21%	80.85%
Min Output on Peak	2.27%	0.00%	1.67%	0.00%
# <10%	7	23	8	22
# 10-20%	3	1	3	2
# 20-30%	7	3	2	1
# 30-40%	10	7	3	5
# 40-50%	4	7	5	3
# 50-60%	12	2	2	3
# 60-70%	3	1	9	6
# 70-80%	4	5	15	7
# 80-90%	0	1	3	1
# 90-100%	0	0	0	0
# >100 %	0	0	0	0

ORIGINAL

Coincidence Analysis EPT SAM

SEIA Analysis using year-specific weather

SP-II-5 ATTACHMENT B (REV)

	PLC					NSPL					400kW Roof SPV		3MW Tracking SPV		Sorted			
	Hour Beginning EPT	Year	Mo	Day	Hr	Hour Beginning EPT	Year	Mo	Day	Hr	% Nameplate Production on PLC	% Nameplate Production on NSPL	% Nameplate Production on PLC	% Nameplate Production on NSPL				
2015	7/28/2015 16:00	2015	7	28	16	1/8/2015 7:00	2015	1	8	7	56.93%	0.00%	84.57%	0.00%	1.28%	0.00%	1.05%	0.00%
	7/20/2015 16:00	2015	7	20	16	2/16/2015 8:00	2015	2	16	8	48.60%	18.97%	67.51%	23.75%	8.50%	0.00%	8.95%	0.00%
	7/29/2015 16:00	2015	7	29	16	2/19/2015 19:00	2015	2	19	19	55.06%	0.00%	80.51%	0.00%	15.59%	0.00%	22.24%	0.00%
	9/3/2015 16:00	2015	9	3	16	2/20/2015 8:00	2015	2	20	8	41.60%	45.24%	56.61%	85.53%	23.75%	0.00%	30.50%	0.00%
	8/17/2015 14:00	2015	8	17	14	2/24/2015 7:00	2015	2	24	7	60.16%	14.49%	64.93%	33.65%	27.61%	0.00%	38.35%	0.00%
	7/25/2016 15:00	2016	7	25	15	1/19/2016 7:00	2016	1	19	7	56.77%	0.00%	66.86%	0.00%	27.70%	0.00%	43.79%	0.00%
2016	7/27/2016 16:00	2016	7	27	16	7/14/2016 16:00	2016	7	14	16	57.14%	57.42%	84.68%	85.23%	30.61%	0.00%	46.37%	0.00%
	8/10/2016 16:00	2016	8	10	16	7/25/2016 13:00	2016	7	25	13	37.38%	64.15%	47.17%	68.05%	31.13%	0.00%	47.17%	0.00%
	8/11/2016 15:00	2016	8	11	15	8/11/2016 14:00	2016	8	11	14	49.81%	73.01%	56.49%	79.87%	31.23%	0.00%	50.14%	0.00%
	8/12/2016 15:00	2016	8	12	15	9/8/2016 16:00	2016	9	8	16	59.38%	41.26%	72.48%	59.43%	33.07%	0.00%	50.64%	0.00%
	6/12/2017 17:00	2017	6	12	17	12/15/2016 18:00	2016	12	15	18	37.88%	0.00%	67.01%	0.00%	33.28%	0.00%	50.73%	0.00%
	6/13/2017 16:00	2017	6	13	16	12/16/2016 7:00	2016	12	16	7	41.83%	0.00%	52.17%	0.00%	33.85%	0.00%	52.17%	0.00%
2017	7/19/2017 17:00	2017	7	19	17	12/20/2016 7:00	2016	12	20	7	33.28%	0.00%	50.14%	0.00%	34.36%	0.00%	53.62%	0.00%
	7/20/2017 16:00	2017	7	20	16	1/9/2017 8:00	2017	1	9	8	48.17%	4.93%	64.49%	5.17%	34.95%	0.00%	56.49%	0.00%
	7/21/2017 16:00	2017	7	21	16	1/10/2017 7:00	2017	1	10	7	51.17%	0.00%	72.35%	0.00%	36.15%	0.09%	56.61%	0.03%
	8/28/2018 17:00	2018	8	28	17	1/3/2018 7:00	2018	1	3	7	33.85%	0.00%	69.15%	0.00%	36.33%	0.48%	57.71%	0.36%
	9/4/2018 17:00	2018	9	4	17	1/4/2018 19:00	2018	1	4	19	31.23%	0.00%	66.77%	0.00%	36.56%	1.42%	58.91%	0.79%
2018	6/18/2018 17:00	2018	6	18	17	1/5/2018 17:00	2018	1	5	17	8.50%	0.00%	8.95%	0.00%	37.38%	4.93%	59.33%	5.17%
	9/5/2018 17:00	2018	9	5	17	7/2/2018 16:00	2018	7	2	16	31.13%	55.08%	66.51%	81.85%	37.88%	9.97%	64.26%	23.75%
	8/27/2018 17:00	2018	8	27	17	8/29/2018 16:00	2018	8	29	16	27.70%	51.97%	46.37%	78.77%	38.69%	14.49%	64.49%	24.63%
	7/10/2019 17:00	2019	7	10	17	1/22/2019 7:00	2019	1	22	7	41.37%	0.00%	77.41%	0.00%	39.58%	18.97%	64.93%	32.47%
	7/17/2019 16:00	2019	7	17	16	1/30/2019 18:00	2019	1	30	18	1.28%	0.00%	1.05%	0.00%	40.55%	21.91%	66.51%	33.65%
2019	7/19/2019 17:00	2019	7	19	17	1/31/2019 7:00	2019	1	31	7	40.75%	0.48%	76.97%	0.36%	40.60%	23.17%	66.70%	34.95%
	7/29/2019 16:00	2019	7	29	16	2/1/2019 7:00	2019	2	1	7	40.55%	0.09%	50.73%	0.03%	40.68%	26.11%	66.77%	38.61%
	8/19/2019 16:00	2019	8	19	16	7/19/2019 16:00	2019	7	19	16	54.09%	55.72%	81.33%	82.06%	40.75%	26.20%	66.86%	40.68%
	7/6/2020 14:00	2020	7	6	14	7/20/2020 17:00	2020	7	20	17	67.74%	42.25%	76.08%	81.17%	41.03%	30.18%	67.01%	42.66%
2020	7/9/2020 17:00	2020	7	9	17	7/22/2020 14:00	2020	7	22	14	40.68%	30.18%	76.19%	32.47%	41.37%	35.20%	67.51%	43.37%
	7/20/2020 16:00	2020	7	20	16	7/27/2020 17:00	2020	7	27	17	57.50%	40.23%	85.31%	76.89%	41.49%	36.15%	69.15%	46.29%
	7/27/2020 16:00	2020	7	27	16	8/10/2020 17:00	2020	8	10	17	56.03%	38.23%	83.28%	73.74%	41.60%	36.56%	72.35%	47.06%
	7/29/2020 17:00	2020	7	29	17	8/11/2020 14:00	2020	8	11	14	39.58%	60.34%	74.53%	65.27%	41.83%	37.96%	72.48%	47.11%
	6/29/2021 16:00	2021	6	29	16	6/28/2021 17:00	2021	6	28	17	47.05%	39.94%	66.70%	76.22%	47.05%	38.23%	73.59%	59.43%
2021	7/6/2021 16:00	2021	7	6	16	6/29/2021 17:00	2021	6	29	17	27.61%	36.15%	30.50%	62.37%	48.17%	39.94%	73.60%	62.37%
	8/12/2021 16:00	2021	8	12	16	6/30/2021 15:00	2021	6	30	15	52.47%	40.75%	78.11%	47.06%	48.28%	40.23%	74.53%	63.83%
	8/24/2021 17:00	2021	8	24	17	8/12/2021 14:00	2021	8	12	14	36.33%	40.76%	74.57%	43.37%	48.60%	40.75%	74.57%	64.26%
	8/26/2021 15:00	2021	8	26	15	8/26/2021 16:00	2021	8	26	16	63.23%	50.67%	78.00%	76.62%	49.56%	40.76%	76.08%	65.27%
	7/20/2022 17:00	2022	7	20	17	1/27/2022 7:00	2022	1	27	7	41.03%	1.42%	77.67%	0.79%	49.81%	41.26%	76.19%	65.69%
2022	7/21/2022 16:00	2022	7	21	16	1/31/2022 8:00	2022	1	31	8	51.05%	21.91%	73.59%	34.95%	51.05%	42.25%	76.68%	68.05%
	7/22/2022 17:00	2022	7	22	17	8/4/2022 14:00	2022	8	4	14	34.36%	37.96%	58.91%	40.68%	51.17%	45.24%	76.97%	72.01%
	8/3/2022 17:00	2022	8	3	17	8/8/2022 16:00	2022	8	8	16	40.60%	51.83%	78.52%	76.18%	52.47%	50.67%	77.41%	73.74%
	8/8/2022 15:00	2022	8	8	15	8/9/2022 14:00	2022	8	9	14	38.69%	23.17%	43.79%	24.63%	54.09%	51.83%	77.67%	76.18%
	7/5/2023 17:00	2023	7	5	17	12/23/2022 18:00	2022	12	23	18	41.49%	0.00%	78.77%	0.00%	55.06%	51.97%	78.00%	76.22%
	7/27/2023 17:00	2023	7	27	17	2/3/2023 19:00	2023	2	3	19	30.61%	0.00%	50.64%	0.00%	56.03%	55.08%	78.11%	76.62%
2023	7/28/2023 17:00	2023	7	28	17	9/5/2023 17:00	2023	9	5	17	33.07%	26.20%	53.62%	47.11%	56.77%	55.16%	78.52%	76.89%
	9/5/2023 16:00	2023	9	5	16	9/6/2023 18:00	2023	9	6	18	48.28%	9.97%	73.60%	38.61%	56.93%	55.72%	78.77%	78.77%
	9/6/2023 16:00	2023	9	6	16	9/7/2023 13:00	2023	9	7	13	49.56%	73.34%	76.68%	72.01%	57.14%	57.42%	80.51%	79.87%
	6/21/2024 17:00	2024	6	21	17	1/17/2024 8:00	2024	1	17	8	34.95%	26.11%	57.71%	42.66%	57.50%	57.56%	81.33%	81.17%
2024	7/15/2024 17:00	2024	7	15	17	7/9/2024 14:00	2024	7	9	14	36.56%	57.56%	64.26%	63.83%	59.38%	60.34%	83.28%	81.85%
	7/16/2024 17:00	2024	7	16	17	7/10/2024 16:00	2024	7	10	16	36.15%	35.20%	59.33%	46.29%	60.16%	64.15%	84.57%	82.06%
	8/1/2024 17:00	2024	8	1	17	7/15/2024 17:00	2024	7	15	17	15.59%	36.56%	22.24%	64.26%	63.23%	73.01%	84.68%	85.23%
	8/28/2024 17:00	2024	8	28	17	7/16/2024 15:00	2024	7	16	15	23.75%	55.16%	38.35%	65.69%	67.74%	73.34%	85.31%	85.53%

Average Output on Peak	41.79%	27.17%	63.28%	38.73%
Avg Output on Peak 2020-2024	41.76%	35.04%	65.24%	50.11%
Max Output on Peak	67.74%	73.34%	85.31%	85.53%
Min Output on Peak	1.28%	0.00%	1.05%	0.00%
# <10%	2	19	2	18
# 10-20%	1	2	0	0
# 20-30%	3	4	1	2
# 30-40%	15	7	2	4
# 40-50%	15	6	3	6
# 50-60%	11	8	10	1
# 60-70%	3	2	10	6
# 70-80%	0	2	16	8
# 80-90%	0	0	6	5
# 90-100%	0	0	0	0
# >100 %	0	0	0	0

PVWatts Hourly PV Performance Data

Requested Location	17837, USA
Location	Lat, Lng: 40.97, -76.9
Latitude (DD)	40.97
Longitude (DD)	-76.9
Elevation (m)	143.25
DC System Size (kW)	480
Module Type	Standard
Array Type	Fixed (roof mount)
Array Tilt (deg)	20
Array Azimuth (deg)	180
System Losses (%)	14.08
DC to AC Size Ratio	1.2
Inverter Efficiency (%)	96
Ground Coverage Ratio	NA
Albedo	From weather file
Bifacial	No (0)
Monthly Irradiance Loss (%)	

Jan	0
Feb	0
Mar	0
Apr	0
May	0
June	0
July	0
Aug	0
Sept	0
Oct	0
Nov	0
Dec	0

Annual Capacity Factor	16.69%

Month	Day	Hour	Beam Irradiance (W/m2)	Diffuse Irradiance (W/m2)	Ambient Temperature (C)	Wind Speed (m/s)	Albedo	Plane of Array Irradiance (W/m2)	Cell Temperature (C)	DC Array Output (W)	AC System Output (W)
1	1	0	0	0	-2	0.3	0.87	0	-2	0	0
1	1	1	0	0	-2	0.3	0.87	0	-2	0	0
1	1	2	0	0	-3	0.3	0.87	0	-3	0	0
1	1	3	0	0	-3	0.2	0.87	0	-3	0	0
1	1	4	0	0	-4	0.2	0.87	0	-4	0	0
1	1	5	0	0	-4	0.2	0.87	0	-4	0	0
1	1	6	0	0	-5	0.2	0.87	0	-5	0	0
1	1	7	0	0	-4	0.2	0.87	0	-4	0	0
1	1	8	0	17	-2	0.2	0.87	16.439	-1.276	6425.93	4295.723
1	1	9	0	42	0	0.3	0.87	40.685	1.75	16797.473	14299.761
1	1	10	0	85	0	0.3	0.87	83.479	3.59	35113.113	31966.406
1	1	11	0	134	0	0.4	0.87	135.413	5.645	57281.178	53348.968
1	1	12	2	148	0	0.4	0.87	152.186	6.344	64432.094	60246.499
1	1	13	0	135	0	0.4	0.87	137.528	5.736	58298.772	54330.505
1	1	14	0	38	-1	0.3	0.87	36.801	0.583	15215.7	12774.037
1	1	15	0	40	-1	0.3	0.87	38.758	0.663	15876.341	13411.269
1	1	16	0	6	-2	0.3	0.87	5.796	-1.786	1444.066	0
1	1	17	0	0	-3	0.2	0.87	0	-3	0	0
1	1	18	0	0	-5	0.2	0.87	0	-5	0	0
1	1	19	0	0	-6	0.2	0.87	0	-6	0	0
1	1	20	0	0	-6	0.2	0.87	0	-6	0	0
1	1	21	0	0	-8	0.2	0.87	0	-8	0	0
1	1	22	0	0	-10	0.4	0.87	0	-10	0	0
1	1	23	0	0	-12	0.5	0.87	0	-12	0	0

PVWatts Hourly PV Performance Data

Requested Location	17837, USA
Location	Lat, Lng: 40.97, -76.9
Latitude (DD)	40.97
Longitude (DD)	-76.9
Elevation (m)	143.25
DC System Size (kW)	3600
Module Type	Premium
Array Type	1-Axis Backtracking
Array Tilt (deg)	0
Array Azimuth (deg)	180
System Losses (%)	14.08
DC to AC Size Ratio	1.2
Inverter Efficiency (%)	96
Ground Coverage Ratio	96
Albedo	From weather file
Bifacial	No (0)
Monthly Irradiance Loss (%)	

Jan	0
Feb	0
Mar	0
Apr	0
May	0
June	0
July	0
Aug	0
Sept	0
Oct	0
Nov	0
Dec	0

Annual Capacity Factor	18.79%

Month	Day	Hour	Beam Irradiance (W/m2)	Diffuse Irradiance (W/m2)	Ambient Temperature (C)	Wind Speed (m/s)	Albedo	Plane of Array Irradiance (W/m2)	Cell Temperature (C)	DC Array Output (W)	AC System Output (W)
1	1	0	0	0	-2	0.3	0.87	0	-2	0	0
1	1	1	0	0	-2	0.3	0.87	0	-2	0	0
1	1	2	0	0	-3	0.3	0.87	0	-3	0	0
1	1	3	0	0	-3	0.2	0.87	0	-3	0	0
1	1	4	0	0	-4	0.2	0.87	0	-4	0	0
1	1	5	0	0	-4	0.2	0.87	0	-4	0	0
1	1	6	0	0	-5	0.2	0.87	0	-5	0	0
1	1	7	0	0	-4	0.2	0.87	0	-4	0	0
1	1	8	0	17	-2	0.2	0.87	16.222	-1.393	46892.126	30961.726
1	1	9	0	42	0	0.3	0.87	34.789	1.273	105652.165	87639.664
1	1	10	0	85	0	0.3	0.87	71.466	2.615	221571.736	199451.744
1	1	11	0	134	0	0.4	0.87	127.218	4.512	398482.056	370093.427
1	1	12	2	148	0	0.4	0.87	146.309	5.188	458761.162	428236.605
1	1	13	0	135	0	0.4	0.87	120.391	4.272	377429.743	349787.081
1	1	14	0	38	-1	0.3	0.87	31.458	0.152	95649.486	77991.419
1	1	15	0	40	-1	0.3	0.87	36.648	0.338	110827.321	92631.444
1	1	16	0	6	-2	0.3	0.87	5.946	-1.816	10975.406	0
1	1	17	0	0	-3	0.2	0.87	0	-3	0	0
1	1	18	0	0	-5	0.2	0.87	0	-5	0	0
1	1	19	0	0	-6	0.2	0.87	0	-6	0	0
1	1	20	0	0	-6	0.2	0.87	0	-6	0	0
1	1	21	0	0	-8	0.2	0.87	0	-8	0	0
1	1	22	0	0	-10	0.4	0.87	0	-10	0	0
1	1	23	0	0	-12	0.5	0.87	0	-12	0	0

ORIGINAL

EXHIBIT KL-19

ORIGINAL

CITIZENS' ELECTRIC COMPANY OF LEWISBURG, PA
DOCKET NO. R-2025-3054394

OCA-XV-1

Please refer to "Attachment A (Rev)" of Citizens' response to SP-II-5, specifically in the portion that states: "PJM costs substantially unaffected by net metered sales." Please explain the effect of net metered sales on PJM costs.

Response Provided By:
Nathan Johnson, President & Chief Executive Officer, Citizens' Electric Company of Lewisburg, PA

Date: August 4, 2025

Response:

The net effect of net-metered sales on PJM costs is better explained by SP-II-5 Attachment B which examines the coincidence of the output of two different hypothetical solar arrays with the Company's historical PJM peak hours for the past ten years. This analysis demonstrates both the low coincidence and high volatility of solar output with respect to peak hours. The company discounts potential savings in PJM Capacity and Transmission costs resulting from net-metered generation because:

1) Net-metered generation cannot be dispatched and is not required or incentivized to export during peak demand periods unless the energy crediting mechanism is the real-time locational marginal price (or another time-differentiated rate that accurately reflects real time conditions).

2) Beyond the lack of incentive to export during peak periods, GSSR-1 customer-generators that produce more than they consume on an annual basis actually benefit from high capacity and transmission prices that inflate the PTC rate they are reimbursed at, which disincentivizes participation during peak demand periods.

3) Net-metered generation, solar in particular, has a low demonstrated coincidence with peak demand periods.

4) Net-metered generation output during peak demand periods is highly volatile because of the influence of weather, seasonal availability, and the variation in seasons, days and times at which peaks occur.

ORIGINAL

EXHIBIT KL-20

ORIGINAL

CITIZENS' ELECTRIC COMPANY OF LEWISBURG, PA
DOCKET NO. R-2025-3054394

OCA-XV-2

Please refer to "Attachment B (Rev)" of Citizens' response to SP-II-5, specifically the Average Output on Peak of 25.36%. Does this net metered generation reduce the load obligation driving PJM costs? If yes, how should this load reduction be incorporated in the analysis in response to SP-II-5?

Response Provided By:
Nathan Johnson, President & Chief Executive Officer, Citizens' Electric Company of Lewisburg, PA

Date: August 4, 2025

Response:

Please see the Company's response to OCA-XV-1. The on Peak Output of net-metered generation may reduce load that determines the PJM obligations determining PJM costs. The Company does not believe it is appropriate to incorporate any capacity or transmission impact into its analysis, however, because net-metered generation does not guarantee those savings and is economically disincentivized to export during peak demand periods. Please note that a customer generator on the GSSR-2 rate would see the benefit of a zero transmission and/or capacity obligation if it successfully offsets its on-site consumption during the relevant PJM peaks.

ORIGINAL

EXHIBIT KL-21

ORIGINAL

CITIZENS' ELECTRIC COMPANY OF LEWISBURG, PA
DOCKET NO. R-2025-3054394

SP-IV-13

Please provide the annual number of customers currently eligible for net metering, and the total exported kWh credited at retail rates, for each of the past three (3) years.

Response Provided By:
Nathan Johnson, President & Chief Executive Officer, Citizens' Electric Company of Lewisburg, PA

Date: August 25, 2025

Response:

The request, as stated, would be burdensome and irrelevant to proposals discussed in rebuttal testimony. The Company, instead, provides a 3-yr analysis of all monthly exports and energy-year-end credits provided to customer-generators.

The Table below provides the requested data for the most recent three available energy-years. Please note that the column titled "Total Monthly Net Exports" is the sum of all months for which a customer in that class *added* kWh to their bank. It does not account for hourly exports later consumed within the same billing period.

Year	Class	# Eligible	# Annual Exporters	Total Monthly Net Exports	EOY Banked kWh
2025	Res	73	41	337,834	60,556
2025	Comm/Ind	15	10	2,608,160	577,510
2024	Res	64	34	106,629	60,709
2024	Comm/Ind	13	8	2,260,521	372,980
2023	Res	51	23	51,625	36,133
2023	Comm/Ind	9	6	768,371	290,821

ORIGINAL

EXHIBIT KL-22

ORIGINAL

Pa. PUC v. Citizens' Electric Company
Docket Nos. R-2025-3054394
Interrogatories of Kelly Road Solar, LLC, Lancaster Avenue Solar, LLC, and Twilight Renewables, LLC (Solar Projects)
OCA Response to Solar Projects Set I

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1. Please refer to OCA Statement 5R at 6, which contains a summary of the Company's argument as to why its proposed Billing Demand proposal is reasonable. Does OCA have an independent perspective of whether the Company's Billing Demand proposal is reasonable? If so, please provide OCA's perspective on this proposal.

In the recent UGI Electric Order[1], one of the contested issues involved a proposed methodology for assigning customers to different rates based upon supply peak load impact (SPLI).
In my opinion, the methodology approved by the PUC in the UGI Electric Order is generally similar to Citizens' proposal in this proceeding. In the UGI Electric Order, the Commission accepted UGI's reasoning that the "approach [would] better align larger net-metering customer-generators with larger customers that have similar grid impacts."[2] In my analysis of Citizens' proposal, I found the methodology to be reasonable for a similar reason, as it would ensure that the overall default service construct, including its rates and rate classification, would be designed efficiently. I addressed this in pages 9-10 of my rebuttal testimony.

2. Please refer to OCA Statement 5R at 9, which contains a summary of the Company's analysis performed in SP-II-5 Attachment A. Has OCA independently validated the quantitative approach used by the Company in this analysis? If so, did it find any deficiencies in the analysis or did it reach the same conclusion as the Company?

While I reviewed and evaluated the quantitative approach presented in SP-II-5 Attachment A, I did not independently validate the quantitative approach by reconciling/cross-checking monetary values and magnitude of costs. Based on my evaluation, the quantitative approach appears sensible, and I did not find the analysis to be deficient. Therefore, I found the direction of the conclusion in SP-II-5 Attachment A (cost comparison/deviation driven by "PJM costs [which would be] substantially unaffected by net metered sales") to be sensible.

3. Please refer to OCA Statement 5R at 12, which states "I take this statement to mean that the large customer-generator (output capacity > 400 kW) stands to benefit from higher prices caused by the risk premiums added to DSP suppliers to address their risks caused by unknown output quantities and attrition risk of large customer-generators."

   a. What is the basis for this assumption, and is it supported by any discovery responses

[1] *Petition of UGI Utilities, Inc-Electric Division for Approval of a Default Service Plan for the Period of June 1, 2025 though May 31, 2029*¸ Docket No. P-2024-3049343, et al (*UGI Electric Order*).
[2] UGI Electric Order, p. 4

provided by the Company?

My assumption is based on two documents.

First, see the following description of UGI's argument in the UGI Electric Order, p. 23:

> The Company determined that if large customer-generators were to be included in the GSR-1 group, then: (1) their output would decrease GSR-1 group load and tranche size; (2) there is substantial question as to the level of output and timing of when these projects will become operational; and (3) these large customer-generators have the ability to leave default service at any time and participate in the wholesale market, thereby creating an attrition risk if projects opt to leave GSR-1 service and shop their output elsewhere. UGI argued that each of these factors would substantially increase risk for wholesale suppliers, causing higher bid premiums and likely reducing the number of competitive bidders.[3]

Second, the response from Citizens to SP-II-5 provides:

> Additionally, while no quantitative analysis has been performed, basic market principles suggest that as the total volume of energy purchased decreases, the price-per-unit will increase. In essence, as more energy is purchased from net-metered exports, less is purchased through the DSP wholesale contract. This lowers the 'buying power' of the DSP while concentrating non-volumetric (Company and supplier admin costs, Capacity, Transmission, and RTEP) costs across a smaller total quantity purchased, increasing the cost per MWh of default supply.
>
> Finally, as purchased net-metered energy creates net under collection of GSSR costs under the existing structure (where the customer generator receives the GSSR-1 price regardless of the generator's size), the resulting reconciliation in future periods through the E-factor inflates the cost of default supply which, in turn, inflates the purchased cost of future-period net-metered energy purchases. In short, net-metered customer-generators directly benefit from the price inflation that they cause in a compounding fashion that increases as more net-metered generation is installed.[4]

The above passages informed my assumption. In the Company's response above, the Company concludes their discussion of uncertainty and market principles by noting "price inflation" after a detailed outline of the cause and effect of under-collection driven by purchased net-metered energy. Given this, I found the statement to be generally comparable to the "bid premium" discussion in the UGI Electric Order.

[3] PA PUC Opinion and Order, p. 23
[4] Citizens' Response to SP-II-5, p. 2

b. Has OCA performed any analysis or research on whether suppliers have included an additional risk premium in their bids when participating in the default service procurement auctions? If so, please provide all such analysis or research.

No, for the following reasons: (1) the OCA is not permitted to see bid details such as these following the completion of default service procurement auctions; and (2) given this lack of information, no further analysis on risk premiums was performed. A qualitative evaluation is provided in my testimony.

4. Please refer to OCA Statement 5R at 15, which states "Mr. Nolt may be overstating the impact of the proposed Billing Demand methodology on customer-generator compensation."

a. Is OCA disputing the calculations that Mr. Nolt provided in his testimony, or does this sentence refer to the lack of clarity on how the Company will compensate customer-generators for excess generation? If the former, please provide all analysis that OCA performed disputing Mr. Nolt's calculations.

This sentence refers to the latter: the lack of clarity on how the Company will compensate customer-generators for excess generation.

5. Please refer to OCA Statement 5R at 16, lines 7-11, discussing the proposed Billing Demand methodology's impact on residential customers with DER.

a. Does OCA believe that commercial customers with behind-the-meter DERs could be impacted by the Company's Billing Demand proposal?

Yes, commercial customers with behind-the-meter DERs could be impacted depending on the output capacity of their DER.

b. If the answer to a) is yes, please provide OCA's position on the impact of the Company's proposed Billing Demand methodology on commercial customers with DERs.

I believe that the Company's Billing Demand proposal could be impactful to these commercial customers. Some customers will be deemed GLP-1 based on the buildings on their premises and might be applied the GSSR-2 rate based on their electricity usage or if the output capacity of their associated DER is greater than 400 kW. If this is the case, aligning the management of supply for this block of larger retail customers alongside a block of larger customer generators should be more

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EXHIBIT KL-23

ORIGINAL

CITIZENS' ELECTRIC COMPANY OF LEWISBURG, PA
DOCKET NO. R-2025-3054394

SP-IV-17

Please produce any PJM or internal system planning guidelines that explicitly require sizing based on GGR rather than measured peak inflow/outflow.

Response Provided By:
Nathan Johnson, President & Chief Executive Officer, Citizens' Electric Company of Lewisburg, PA

Date: August 25, 2025

Response:

PJM does not specify planning criteria for distribution level, net-metered generation.

The Company does not maintain a written planning guideline that explicitly requires sizing based on GGR because distribution system planning is done by two employees (i.e., the President & Chief Executive Officer and/or the Senior Director of Engineering & Operations). As such, a written planning guideline is not necessary. The Company has consistently utilized this value in its planning calculations based on internal engineering judgement with support from management.

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Exhibit Nos. KL-8 through KL-22

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EXHIBIT KL-8

CITIZENS' ELECTRIC COMPANY OF LEWISBURG, PA
DOCKET NO. R-2025-3054394

SP-VI-5

Please refer to Citizens' Statement No. 4R at 23, which states "Second, I disagree with the implication that a customer who installs on-site generation with capacity that exceeds the historic account generation demand is not changing its use of the distribution system. The customer is placing a new obligation on Citizens' and on the distribution system by exporting more energy than it previously imported, and then expecting the return of the "banked" excess supply on-demand."

a. Confirm that a distribution asset that is able to serve a given level of peak demand can also serve all levels of demand up to that level of peak demand. That is, if a piece of equipment can serve 100 kW of demand, it can also serve demands from 0 to 100 kW. If deny, please explain in detail.

b. Is it the Company's position that the new "obligations" discussed above always result in incremental costs to serve its customers? If so, please provide all analyses that the Company has performed to support that position.

c. If the new "obligations" above do not result in incremental costs to serve its customers, does the Company believe it is appropriate to charge the customer-generator more after installing the on-stie generation? Please explain in full.

Response Provided By:
Nathan Johnson, President & Chief Executive Officer, Citizens' Electric Company of Lewisburg, PA

Date: August 25, 2025

Response:

a. Confirmed.

b. No, new obligations, whether from newly installed load or generation, or simply changing load characteristics, do not always result in incremental cost increases to operate and maintain the system; however, the new obligations may support changing the account's proportionate cost responsibility for the shared distribution resources.

c. Yes, just as obligations from new or increased load that increase peak consumed demand will result in increased charges to customers—regardless of whether specific, measurable incremental cost increases can be directly correlated to the new load—the Company proposes to charge exported 'demand' in a similar manner. The Company cannot reasonably calculate the exact incremental costs incurred by each individual customer on an ongoing basis, which is one of the reasons why tariffed rates are used. Billing demand

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EXHIBIT KL-9

CITIZENS' ELECTRIC COMPANY OF LEWISBURG, PA
DOCKET NO. R-2025-3054394

SP-VI-5

Please refer to Citizens' Statement No. 4R at 23, which states "Second, I disagree with the implication that a customer who installs on-site generation with capacity that exceeds the historic account generation demand is not changing its use of the distribution system. The customer is placing a new obligation on Citizens' and on the distribution system by exporting more energy than it previously imported, and then expecting the return of the "banked" excess supply on-demand."

a. Confirm that a distribution asset that is able to serve a given level of peak demand can also serve all levels of demand up to that level of peak demand. That is, if a piece of equipment can serve 100 kW of demand, it can also serve demands from 0 to 100 kW. If deny, please explain in detail.

b. Is it the Company's position that the new "obligations" discussed above always result in incremental costs to serve its customers? If so, please provide all analyses that the Company has performed to support that position.

c. If the new "obligations" above do not result in incremental costs to serve its customers, does the Company believe it is appropriate to charge the customer-generator more after installing the on-stie generation? Please explain in full.

Response Provided By:
Nathan Johnson, President & Chief Executive Officer, Citizens' Electric Company of Lewisburg, PA

Date: August 25, 2025

Response:

a. Confirmed.

b. No, new obligations, whether from newly installed load or generation, or simply changing load characteristics, do not always result in incremental cost increases to operate and maintain the system; however, the new obligations may support changing the account's proportionate cost responsibility for the shared distribution resources.

c. Yes, just as obligations from new or increased load that increase peak consumed demand will result in increased charges to customers—regardless of whether specific, measurable incremental cost increases can be directly correlated to the new load—the Company proposes to charge exported 'demand' in a similar manner. The Company cannot reasonably calculate the exact incremental costs incurred by each individual customer on an ongoing basis, which is one of the reasons why tariffed rates are used. Billing demand

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EXHIBIT KL-10

REVISED

CITIZENS' ELECTRIC COMPANY OF LEWISBURG, PA
DOCKET NO. R-2025-3054394

SP-I-19

Do customer generators primarily exporting 450 kW net metered systems pay for electrical infrastructure upgrades needed to interconnect to the grid safely?

Response Provided By:
Nathan Johnson, President & CEO, Citizens' Electric Company

Date: June 26, 2025

Response:

Net-metered customer-generators must pay for required system upgrades, based on location-specific distribution system characteristics, needed for their system to safely interconnect and operate in parallel with the Company's distribution system.

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EXHIBIT KL-11

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CITIZENS' ELECTRIC COMPANY OF LEWISBURG, PA
DOCKET NO. R-2025-3054394

SP-I-20

Do customer generators pay for a detailed engineering study to ensure a net metering system will not cause adverse grid conditions as a result of their interconnection?

Response Provided By:
Nathan Johnson, President & CEO, Citizens' Electric Company

Date: June 26, 2025

Response:

Yes, customer-generators are required to pay for detailed engineering, as necessitated by location-specific distribution system characteristics, to ensure safe interconnection.

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EXHIBIT KL-12

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CITIZENS' ELECTRIC COMPANY OF LEWISBURG, PA
DOCKET NO. R-2025-3054394

SP-V-2

Please refer to Statement No. 1R at 17, which states "The Company must stand ready to serve both of these loads, at any time, in either direction. Whether the customer is drawing 400 kW from the grid, or injecting 400 kW, the Company needs the same assets to serve the customer's needs."

a. Suppose a customer with a 400 kW peak demand is on a feeder that serves 3 MW of peak demand from all customers connected to that feeder. Further suppose that this customer installs a solar generator that enables it to export 400 kW of power to the grid, and that this generator passed the Company's interconnection screening process without triggering any system upgrade costs.

   i. Please indicate all additional pieces of equipment that the Company must install to serve the 400 kW of exported power that did not already exist to serve the 400 kW of imported power.

   ii. Please identify any incremental cost associated with serving the 400 kW of exported power that are solely the result of the presence of exported power and were not required to serve the 400 kW of imported power.

   iii. Does the Company believe that the 400 kW of exported power will ever increase the peak demand served by the feeder? If yes, please explain the circumstances in which that would occur.

Response Provided By:
Nathan Johnson, President & Chief Executive Officer, Citizens' Electric Company of Lewisburg, PA

Date: August 25, 2025

Response:

The Company cannot provide specific answers to subparts (i) and (ii) of this question. What, if any, distribution costs incurred and/or necessary upgrades will result from the addition of generation of new generation, even with a peak output equal to or less than existing load, is unique for each customer-generator based upon their individual load characteristics, coincidence of load and generation, characteristics of surrounding customers loads and generation, and the existing construction of the distribution system supplying them.

iii. No, adding generation will not increase feeder peak demand.

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EXHIBIT KL-13

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CITIZENS' ELECTRIC COMPANY OF LEWISBURG, PA
DOCKET NO. R-2025-3054394

SP-IV-6

Please state whether the Company has conducted any cost-of-service study comparing the cost responsibility of customer-generators under (a) actual metered peak inflow/outflow demand and (b) GGR-based billing demand. If so, provide the date, authors, and conclusions.

Response Provided By:
Nathan Johnson, President & Chief Executive Officer, Citizens' Electric Company of Lewisburg, PA

Date: August 25, 2025

Response:

The Company has not conducted a rate analysis directly comparing the demand quantities listed above. At this time, the Company does not have the metering capability to measure bi-directional demand.

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EXHIBIT KL-14

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CITIZENS' ELECTRIC COMPANY OF LEWISBURG, PA
DOCKET NO. R-2025-3054394

SP-IV-23

Please confirm that the Company has not conducted a cost-of-service study isolating the marginal cost of exports from distributed generation.

Response Provided By:
Nathan Johnson, President & Chief Executive Officer, Citizens' Electric Company of Lewisburg, PA

Date: August 25, 2025

Response:

Confirmed, the Company does not conduct marginal cost studies.

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EXHIBIT KL-15

REVISED

CITIZENS' ELECTRIC COMPANY OF LEWISBURG, PA
DOCKET NO. R-2025-3054394

SP-V-3

Please refer to Statement No. 1R at 17, which states "Mr. Lucas' opinion that Citizens' proposal is not in accord with the traditional "billing demand" as used in distribution ratemaking (i.e., the amount that the account imports from the utility) is incorrect.

a. Please list all other instances the Company is aware of where a utility uses a measurement of billing demand in its cost of service, cost allocation, or rate design for distribution rates that is consistent with the Company's proposed Billing Demand methodology.

Response Provided By:
Howard S. Gorman, President, HSG Group
Nathan Johnson, President & Chief Executive Officer, Citizens' Electric Company of Lewisburg, PA

Date: August 25, 2025

Response:

The Company is unaware of any unbundled distribution rates that use the definition of "Billing Demand" proposed in this case; however, the proposal is consistent with traditional cost of service principles and reflects the evolving bi-directional use of the distribution system.

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EXHIBIT KL-16

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CITIZENS' ELECTRIC COMPANY OF LEWISBURG, PA
DOCKET NO. R-2025-3054394

SP-III-1

Please refer to the Company's response to SP-II-3, which states "The most obvious example of instability caused by DER is intermittent cloud cover over solar arrays. A cloud bank passing over a group of large distribution arrays can cause a significant change in power flow over a very short time period, causing a voltage sag. This causes voltage control devices on the system to react to restore voltage, but may then result in a subsequent voltage surge as the clouds pass and SPV output returns to its full potential. Aside from the immediate concern of voltage instability, this increases the duty cycle of voltage control devices, which shortens their expected lifespans. It may also negatively impact nearby consumers."

a. Confirm whether the voltage control devices referred to above are manually adjusted, actively adjusted, or function passively. To the extent there are different types of voltage control devices being referred to in the response, please expand how each type would respond to the event discussed above.
b. On what time frame (sub-second, second, minutes, etc.) do the voltage control devices operate to correct system voltage?
c. Please confirm that the Company's interconnection process screens for the types of voltage instability discussed above. If denied, please explain.
d. If c) above is confirmed, will the Company allow a DER to connect to its grid without requiring customer-generator-funded system upgrades? Please explain the process in detail.
e. Suppose the Company has a commercial customer with a 400 kW load, 200 kW of which can rapidly switch on and off.
    i. Confirm that the customer's rapidly changing load can cause a significant change in power flow on the Company's system over a short time period. If denied, please explain in detail why.
    ii. Confirm that the customer's rapidly changing load can impact voltage on the Company's system. If denied, please explain in detail why.
    iii. Confirm that voltage control systems on the Company's grid will react to restore voltage as this customer's load changes rapidly. If denied, please explain in detail why.
    iv. Please explain all differences in the impact on the grid of a PV system that sees a 200 kW reduction in power output over 10 seconds from a passing cloud and a customer with a large load activating 200 kW of load over 10 seconds.

Response Provided By:
Nathan Johnson, President & Chief Executive Officer, Citizens' Electric Company

Date: July 14, 2025

Response:

a. The voltage control devices referred to are automated devices that respond to deviations from programmed time-voltage criteria to correct system voltage. The Company uses both automatically controlled capacitor banks and regulators. The Company does utilize 'fixed' and manually energy capacitors, but neither are relevant to the circumstances referred to in this question and response.

b. Typical voltage control devices on the Company's system use two levels of criteria. Under both criteria, devices can react to changes in system voltage within seconds. More importantly, to provide for stability and prevent 'hunting' (a phenomenon where nearby devices react to each other, rather than system-driven changes), devices have a time delay between operations and may also use a longer time delay if more than a pre-determined number of operations occur within a set period. Devices also have 'override' criteria to prevent system voltages from deviating out of a wider, pre-determined bandwidth. Override criteria has fewer limitations on the interval and number of operations.

c. Confirmed, the company screens for the potential incremental system impact of each interconnection.

d. Customers are required to fund system upgrades to mitigate potential disruption or instability caused by their interconnection. The Company's system modelling software allows it to model proposed interconnections and evaluate their effect on system conditions, including voltage. If disruptions can be handled by the Company's existing equipment, then no upgrade funding will be required prior to interconnection. If unacceptable effects are indicated, mitigating upgrades can be modeled and tested for effectiveness to identify the most practical and economical solution. Once a solution is identified, a magnitude estimate for the upgrade is developed and provided to the customer for them to determine if they wish to proceed with the interconnection as planned, discuss potential modifications with engineering to lessen costs, or abandon the application.

e. Regarding a customer with 200kW of rapidly fluctuating load:

   i. Denied, a rapidly shifting 200kW load may cause some 'hyper-local' changes in power flow, but a 200kW shift in load is unlikely to affect power flow on a system scale.

   ii. Denied, similar to subpart (i), a rapidly shifting 200kW load may cause some 'hyper-local' voltage impacts, affecting customers in their immediate area. Once this impact was identified, the customer would be required to make changes to mitigate these effects.

   iii. Confirmed, if a change in customer load causes a voltage disruption of sufficient magnitude to affect system voltage, installed voltage control devices will react to

stabilize voltage. As noted above, the customer may be required to make changes to mitigate ongoing voltage disruptions.

iv. There is little difference in system impact between a rapid change in a 200kW customer load and 200kW of PV generation; both situations may require corrective actions by the account and/or the operation of on-system control devices.

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EXHIBIT KL-17

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CITIZENS' ELECTRIC COMPANY OF LEWISBURG, PA
DOCKET NO. R-2025-3054394

SP-II-5

Please reference Citizens' St. No. 4, p. 17. Has Citizens conducted any studies or analyses of the effects of this tariff change on Citizens' default procurement of electricity based on its Default Service Plan ("DSP")? If yes, please provide all studies or analyses related to the same.

Response Provided By:
Nathan Johnson, President & CEO

Date: June 30, 2025 (original)
July 14, 2025 (revised)

Response:

July 14, 2025 Revisions:
The Company has revised the attachments ("SP-II-5 Attachment A" and "SP-II-5 Attachment B") provided with the original response to SP-II-5, and made revisions to the response below, highlighted in yellow after identifying a data error related to the AC-to-DC ratio of the model PV systems used.

Original Response with July 14, 2025 Revision Incorporated:

Yes, the Company has analyzed the impact of net metered energy on default service costs in two different ways:

1) The direct cost of purchased net-metered energy compared to the cost of purchasing the same volume of energy through the DSP.

2) The potential for net-metered generation to mitigate PJM Capacity, Transmission, and RTEP costs.

The purchase cost analysis can be found in the attachment titled "SP-II-5 Attachment A (REV)." It contains several comparisons, summarized in the table below:

Comparison	Description	Result
400kW	400kW$_{AC}$ Roof Mount SPV w/ no offset load, standard PVWatts® roof-mount parameters	~$27,000 increase in GSSR-1 costs annually.
Ex + Prop >400kW	Expected net-metered export purchases of existing and proposed systems with ≥400kW rated output capacity	~$88,000 increase in GSSR-1 costs annually.

3000kW	3MW$_{AC}$ Rack Mounted Tracking (w/ Backtracking) SPV, premium panels, standard PVWatts® parameters	~$230,000 increase in GSSR-1 costs annually.

The analysis of PJM cost mitigation can be found in the attachment titled "SP-II-5 Attachment B (REV)." It contains a ten year history of PJM Capacity and Transmission peak hours and hourly outputs from the same PVWatts® studies used in Attachment A (REV). For nearly half of the past decade's PJM Capacity and Transmission Peak hours, SPV output from either model was 20% or less of rated capacity, demonstrating the limited ability of net-metered SPV to mitigate PJM costs.

Additionally, while no quantitative analysis has been performed, basic market principles suggest that as the total volume of energy purchased decreases, the price-per-unit will increase. In essence, as more energy is purchased from net-metered exports, less is purchased through the DSP wholesale contract. This lowers the 'buying power' of the DSP while concentrating non-volumetric (Company and supplier admin costs, Capacity, Transmission, and RTEP) costs across a smaller total quantity purchased, increasing the cost per MWh of default supply.

Finally, as purchased net-metered energy creates net under collection of GSSR costs under the existing structure (where the customer generator receives the GSSR-1 price regardless of the generator's size), the resulting reconciliation in future periods through the E-factor inflates the cost of default supply which, in turn, inflates the purchased cost of future-period net-metered energy purchases. In short, net-metered customer-generators directly benefit from the price inflation that they cause in a compounding fashion that increases as more net-metered generation is installed.

The Company concludes from its analysis that 1) net-metered generation exports result in a significant increase to default supply costs and 2) its proposed tariff change will mitigate these increases by shifting large exporters to the GSSR-2 rate and corresponding reimbursement formula.

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Coincidence Analysis

Original Company Analysis

SP-II-5 ATTACHMENT B (REV)

	PLC				NSPL				400kW Roof SPV		3MW Tracking SPV		Sorted			
	Hour Beginning	Mo	Day	Hr	Hour Beginning	Mo	Day	Hr	% Nameplate Production on PLC	% Nameplate Production on NSPL	% Nameplate Production on PLC	% Nameplate Production on NSPL				
2015	7/28/2015 16:00	7	28	16	1/8/2015 7:00	1	8	7	8.93%	0.00%	7.05%	0.00%	0.00%	0.00%	0.00%	0.00%
	7/20/2015 16:00	7	20	16	2/16/2015 8:00	2	16	8	24.77%	0.60%	29.27%	0.49%	0.50%	0.00%	0.46%	0.00%
	7/29/2015 16:00	7	29	16	2/19/2015 19:00	2	19	19	29.75%	0.00%	40.54%	0.00%	0.50%	0.00%	0.46%	0.00%
	9/3/2015 16:00	9	3	16	2/20/2015 8:00	2	20	8	27.07%	21.85%	47.63%	30.00%	1.32%	0.00%	1.76%	0.00%
	8/17/2015 14:00	8	17	14	2/24/2015 7:00	2	24	7	57.22%	5.57%	62.59%	6.62%	8.04%	0.00%	6.75%	0.00%
	7/25/2016 15:00	7	25	15	1/19/2016 7:00	1	19	7	59.58%	0.00%	80.74%	0.00%	8.10%	0.00%	6.75%	0.00%
2016	7/27/2016 16:00	7	27	16	7/14/2016 16:00	7	14	16	32.42%	27.36%	47.93%	34.99%	8.10%	0.00%	6.84%	0.00%
	8/10/2016 16:00	8	10	16	7/25/2016 13:00	7	25	13	37.56%	78.36%	66.54%	80.90%	8.24%	0.00%	7.03%	0.00%
	8/11/2016 15:00	8	11	15	8/11/2016 14:00	8	11	14	58.99%	71.28%	80.86%	81.03%	8.93%	0.00%	7.05%	0.00%
	8/12/2016 15:00	8	12	15	9/8/2016 16:00	9	8	16	55.04%	31.22%	75.46%	63.41%	8.93%	0.00%	7.05%	0.00%
	6/12/2017 17:00	6	12	17	12/15/2016 18:00	12	15	18	14.83%	0.00%	23.67%	0.00%	9.84%	0.00%	8.52%	0.00%
	6/13/2017 16:00	6	13	16	12/16/2016 7:00	12	16	7	8.93%	0.00%	7.05%	0.00%	10.46%	0.00%	9.87%	0.00%
2017	7/19/2017 17:00	7	19	17	12/20/2016 7:00	12	20	7	8.10%	0.00%	6.75%	0.00%	10.73%	0.00%	17.29%	0.00%
	7/20/2017 16:00	7	20	16	1/9/2017 8:00	1	9	8	24.77%	8.43%	29.27%	8.37%	11.42%	0.00%	22.68%	0.00%
	7/21/2017 16:00	7	21	16	1/10/2017 7:00	1	10	7	38.86%	0.00%	62.30%	0.00%	13.38%	0.00%	23.67%	0.00%
	8/28/2018 17:00	8	28	17	1/3/2018 7:00	1	3	7	0.50%	0.00%	0.46%	0.00%	14.35%	0.00%	28.23%	0.00%
	9/4/2018 17:00	9	4	17	1/4/2018 19:00	1	4	19	11.42%	0.00%	32.39%	0.00%	14.83%	0.00%	29.27%	0.00%
2018	6/18/2018 17:00	6	18	17	1/5/2018 17:00	1	5	17	9.84%	0.00%	8.52%	0.00%	14.95%	0.31%	29.27%	0.31%
	9/5/2018 17:00	9	5	17	7/2/2018 16:00	7	2	16	10.73%	34.82%	28.23%	52.47%	16.30%	0.60%	29.27%	0.49%
	8/27/2018 17:00	8	27	17	8/29/2018 16:00	8	29	16	1.32%	36.86%	1.76%	71.31%	17.93%	1.74%	29.82%	1.67%
	7/10/2019 17:00	7	10	17	1/22/2019 7:00	1	22	7	0.00%	0.00%	0.00%	0.00%	19.03%	2.27%	31.98%	1.67%
	7/17/2019 16:00	7	17	16	1/30/2019 18:00	1	30	18	44.37%	0.00%	76.72%	0.00%	19.04%	3.91%	32.39%	2.95%
2019	7/19/2019 17:00	7	19	17	1/31/2019 7:00	1	31	7	8.10%	0.31%	6.75%	0.31%	20.28%	5.57%	35.91%	6.62%
	7/29/2019 16:00	7	29	16	2/1/2019 7:00	2	1	7	29.75%	0.00%	40.54%	0.00%	21.87%	8.04%	38.71%	7.03%
	8/19/2019 16:00	8	19	16	7/19/2019 16:00	7	19	16	36.97%	2.27%	68.40%	1.67%	23.53%	8.43%	40.54%	8.37%
	7/6/2020 14:00	7	6	14	7/20/2020 17:00	7	20	17	56.55%	10.46%	61.60%	9.87%	24.77%	10.46%	40.54%	9.87%
	7/9/2020 17:00	7	9	17	7/22/2020 14:00	7	22	14	8.24%	64.59%	6.84%	72.82%	24.77%	10.73%	44.40%	12.15%
2020	7/20/2020 16:00	7	20	16	7/27/2020 17:00	7	27	17	24.77%	8.04%	29.27%	7.03%	24.77%	11.96%	46.30%	17.29%
	7/27/2020 16:00	7	27	16	8/10/2020 17:00	8	10	17	32.42%	19.06%	47.93%	53.89%	25.42%	13.38%	47.63%	28.23%
	7/29/2020 17:00	7	29	17	8/11/2020 14:00	8	11	14	16.30%	71.28%	31.98%	81.03%	27.07%	19.06%	47.93%	30.00%
	6/29/2021 16:00	6	29	16	6/28/2021 17:00	6	28	17	42.61%	11.96%	74.09%	12.15%	29.75%	21.85%	47.93%	33.37%
	7/6/2021 16:00	7	6	16	6/29/2021 17:00	6	29	17	25.42%	3.91%	29.82%	2.95%	29.75%	27.36%	49.53%	34.99%
2021	8/12/2021 16:00	8	12	16	6/30/2021 15:00	6	30	15	38.67%	54.94%	69.83%	72.91%	31.22%	27.38%	55.18%	35.00%
	8/24/2021 17:00	8	24	17	8/12/2021 14:00	8	12	14	14.95%	66.75%	38.71%	75.74%	32.42%	28.30%	59.51%	36.08%
	8/26/2021 15:00	8	26	15	8/26/2021 16:00	8	26	16	49.49%	36.72%	66.39%	69.41%	32.42%	31.22%	60.66%	49.38%
	7/20/2022 17:00	7	20	17	1/27/2022 7:00	1	27	7	10.46%	0.00%	9.87%	0.00%	33.56%	34.82%	61.60%	52.47%
	7/21/2022 16:00	7	21	16	1/31/2022 8:00	1	31	8	38.86%	28.30%	62.30%	36.08%	36.97%	35.22%	62.30%	53.89%
2022	7/22/2022 17:00	7	22	17	8/4/2022 14:00	8	4	14	20.28%	46.50%	44.40%	49.38%	37.56%	36.72%	62.30%	57.33%
	8/3/2022 17:00	8	3	17	8/8/2022 16:00	8	8	16	19.03%	37.44%	46.30%	64.49%	38.67%	36.86%	62.59%	63.41%
	8/8/2022 15:00	8	8	15	8/9/2022 14:00	8	9	14	46.83%	61.80%	60.66%	68.97%	38.86%	37.44%	66.39%	64.49%
	7/5/2023 17:00	7	5	17	12/23/2022 18:00	12	23	18	23.53%	0.00%	66.69%	0.00%	38.86%	46.50%	66.54%	68.97%
	7/27/2023 17:00	7	27	17	2/3/2023 19:00	2	3	19	8.04%	0.00%	7.03%	0.00%	42.61%	47.25%	66.69%	69.41%
2023	7/28/2023 17:00	7	28	17	9/5/2023 17:00	9	5	17	14.35%	10.73%	22.68%	28.23%	44.37%	54.94%	67.09%	71.31%
	9/5/2023 16:00	9	5	16	9/6/2023 18:00	9	6	18	33.56%	0.00%	67.09%	0.00%	46.83%	61.80%	68.40%	72.82%
	9/6/2023 16:00	9	6	16	9/7/2023 13:00	9	7	13	31.22%	35.22%	59.51%	33.37%	49.49%	64.59%	69.83%	72.91%
	6/21/2024 17:00	6	21	17	1/17/2024 8:00	1	17	8	21.87%	1.74%	55.18%	1.67%	55.04%	66.75%	74.09%	75.74%
	7/15/2024 17:00	7	15	17	7/9/2024 14:00	7	9	14	13.38%	69.82%	17.29%	80.51%	56.55%	69.82%	75.46%	80.51%
2024	7/16/2024 17:00	7	16	17	7/10/2024 16:00	7	10	16	17.93%	27.38%	35.91%	35.00%	57.22%	71.28%	76.72%	80.90%
	8/1/2024 17:00	8	1	17	7/15/2024 17:00	7	15	17	19.04%	13.38%	49.53%	17.29%	58.99%	71.28%	80.74%	81.03%
	8/28/2024 17:00	8	28	17	7/16/2024 15:00	7	16	15	0.50%	47.25%	0.46%	57.33%	59.58%	78.36%	80.86%	81.03%

Average Output on Peak	25.36%	20.92%	39.85%	27.23%
Max Output on Peak	59.58%	78.36%	80.86%	81.03%
Min Output on Peak	0.00%	0.00%	0.00%	0.00%
# <10%	11	25	12	26
# 10-20%	11	5	1	2
# 20-30%	10	4	7	1
# 30-40%	9	6	4	5
# 40-50%	4	2	8	1
# 50-60%	5	1	2	3
# 60-70%	0	4	11	4
# 70-80%	0	3	3	4
# 80-90%	0	0	2	4
# 90-100%	0	0	0	0
# >100 %	0	0	0	0

REVISED

Coincidence Analysis - EPT Fix

Original Company Analysis with DST Fix

SP-II-5 ATTACHMENT B (REV)

	PLC				NSPL				400kW Roof SPV		3MW Tracking SPV		Sorted			
	Hour Beginning	Mo	Day	Hr	Hour Beginning	Mo	Day	Hr	% Nameplate Production on PLC	% Nameplate Production on NSPL	% Nameplate Production on PLC	% Nameplate Production on NSPL				
2015	7/28/2015 16:00	7	28	15	1/8/2015 7:00	1	8	7	26.71%	0.00%	25.86%	0.00%	2.27%	0.00%	1.67%	0.00%
	7/20/2015 16:00	7	20	15	2/16/2015 8:00	2	16	8	55.81%	0.60%	73.80%	0.49%	2.27%	0.00%	1.67%	0.00%
	7/29/2015 16:00	7	29	15	2/19/2015 19:00	2	19	19	39.16%	0.00%	43.95%	0.00%	3.80%	0.00%	2.88%	0.00%
	9/3/2015 16:00	9	3	15	2/20/2015 8:00	2	20	8	11.62%	21.85%	9.80%	30.00%	7.64%	0.00%	5.91%	0.00%
	8/17/2015 14:00	8	17	13	2/24/2015 7:00	2	24	7	71.70%	5.57%	71.63%	6.62%	7.78%	0.00%	6.26%	0.00%
2016	7/25/2016 15:00	7	25	14	1/19/2016 7:00	1	19	7	70.79%	0.00%	81.01%	0.00%	7.78%	0.00%	6.26%	0.00%
	7/27/2016 16:00	7	27	15	7/14/2016 16:00	7	14	15	50.95%	37.38%	65.91%	41.18%	8.93%	0.00%	7.05%	0.00%
	8/10/2016 16:00	8	10	15	7/25/2016 13:00	7	25	12	57.20%	81.99%	78.14%	80.85%	11.62%	0.00%	9.80%	0.00%
	8/11/2016 15:00	8	11	14	8/11/2016 14:00	8	11	13	71.28%	76.25%	81.03%	76.86%	15.65%	0.00%	13.94%	0.00%
	8/12/2016 15:00	8	12	14	9/8/2016 16:00	9	8	15	66.75%	50.42%	75.74%	71.95%	18.79%	0.00%	17.98%	0.00%
2017	6/12/2017 17:00	6	12	16	12/15/2016 18:00	12	15	18	41.74%	0.00%	74.26%	0.00%	20.70%	0.00%	19.36%	0.00%
	6/13/2017 16:00	6	13	15	12/16/2016 7:00	12	16	7	7.64%	0.00%	5.91%	0.00%	24.49%	0.00%	25.86%	0.00%
	7/19/2017 17:00	7	19	16	12/20/2016 7:00	12	20	7	2.27%	0.00%	1.67%	0.00%	24.77%	0.00%	29.27%	0.00%
	7/20/2017 16:00	7	20	15	1/9/2017 8:00	1	9	8	55.81%	8.43%	73.80%	8.37%	26.71%	0.00%	33.15%	0.00%
	7/21/2017 16:00	7	21	15	1/10/2017 7:00	1	10	7	53.56%	0.00%	69.45%	0.00%	27.38%	0.00%	35.00%	0.00%
2018	8/28/2018 17:00	8	28	16	1/3/2018 7:00	1	3	7	7.78%	0.00%	6.26%	0.00%	28.74%	0.00%	37.23%	0.00%
	9/4/2018 17:00	9	4	16	1/4/2018 19:00	1	4	19	35.07%	0.00%	70.79%	0.00%	29.75%	0.31%	40.54%	0.31%
	6/18/2018 17:00	6	18	16	1/5/2018 17:00	1	5	17	38.43%	0.00%	62.86%	0.00%	31.69%	0.60%	42.55%	0.49%
	9/5/2018 17:00	9	5	16	7/2/2018 16:00	7	2	15	33.56%	48.49%	67.09%	61.36%	32.42%	1.74%	43.95%	1.54%
	8/27/2018 17:00	8	27	16	8/29/2018 16:00	8	29	15	3.80%	44.64%	2.88%	59.38%	33.56%	2.11%	43.95%	1.67%
2019	7/10/2019 17:00	7	10	16	1/22/2019 7:00	1	22	7	27.38%	0.00%	35.00%	0.00%	34.21%	5.57%	47.93%	6.62%
	7/17/2019 16:00	7	17	15	1/30/2019 18:00	1	30	18	60.48%	0.00%	82.21%	0.00%	35.07%	7.45%	50.38%	8.37%
	7/19/2019 17:00	7	19	16	1/31/2019 7:00	1	31	7	2.27%	0.31%	1.67%	0.31%	38.43%	8.43%	52.35%	13.94%
	7/29/2019 16:00	7	29	15	2/1/2019 7:00	2	1	7	39.16%	0.00%	43.95%	0.00%	38.49%	15.65%	61.21%	14.00%
	8/19/2019 16:00	8	19	15	7/19/2019 16:00	7	19	15	52.32%	43.57%	71.95%	51.66%	39.09%	21.85%	62.86%	29.27%
2020	7/6/2020 14:00	7	6	13	7/20/2020 17:00	7	20	16	72.26%	24.77%	74.68%	29.27%	39.16%	24.77%	65.91%	30.00%
	7/9/2020 17:00	7	9	16	7/22/2020 14:00	7	22	13	18.79%	62.28%	19.36%	63.09%	39.16%	28.30%	65.91%	31.58%
	7/20/2020 16:00	7	20	15	7/27/2020 17:00	7	27	16	55.81%	32.42%	73.80%	47.93%	40.80%	32.32%	66.80%	33.62%
	7/27/2020 16:00	7	27	15	8/10/2020 17:00	8	10	16	50.95%	37.56%	65.91%	66.54%	41.21%	32.42%	67.09%	36.08%
	7/29/2020 17:00	7	29	16	8/11/2020 14:00	8	11	13	29.75%	76.25%	40.54%	76.86%	41.74%	33.56%	69.45%	38.81%
2021	6/29/2021 16:00	6	29	15	6/28/2021 17:00	6	28	16	58.37%	2.11%	79.91%	1.54%	45.09%	33.90%	69.45%	41.18%
	7/6/2021 16:00	7	6	15	6/29/2021 17:00	6	29	16	20.70%	42.61%	17.98%	74.09%	50.95%	37.38%	69.47%	41.97%
	8/12/2021 16:00	8	12	15	6/30/2021 15:00	6	30	14	55.04%	54.69%	75.46%	59.45%	50.95%	37.56%	70.79%	47.93%
	8/24/2021 17:00	8	24	16	8/12/2021 14:00	8	12	13	24.49%	74.42%	37.23%	75.27%	52.32%	37.85%	71.23%	51.66%
	8/26/2021 15:00	8	26	14	8/26/2021 16:00	8	26	15	60.49%	49.49%	66.80%	66.39%	53.32%	40.72%	71.63%	59.38%
2022	7/20/2022 17:00	7	20	16	1/27/2022 7:00	1	27	7	24.77%	0.00%	29.27%	0.00%	53.56%	42.61%	71.95%	59.45%
	7/21/2022 16:00	7	21	15	1/31/2022 8:00	1	31	8	53.56%	28.30%	69.45%	36.08%	53.56%	43.57%	73.80%	60.66%
	7/22/2022 17:00	7	22	16	8/4/2022 14:00	8	4	13	38.49%	73.00%	61.21%	74.18%	55.04%	44.64%	73.80%	61.36%
	8/3/2022 17:00	8	3	16	8/8/2022 16:00	8	8	15	28.74%	46.83%	42.55%	60.66%	55.81%	46.83%	73.80%	63.09%
	8/8/2022 15:00	8	8	14	8/9/2022 14:00	8	9	13	31.69%	77.42%	33.15%	78.37%	55.81%	48.49%	74.26%	66.39%
2023	7/5/2023 17:00	7	5	16	12/23/2022 18:00	12	23	18	45.09%	0.00%	78.49%	0.00%	55.81%	49.49%	74.68%	66.54%
	7/27/2023 17:00	7	27	16	2/3/2023 19:00	2	3	19	32.42%	0.00%	47.93%	0.00%	57.20%	50.42%	75.46%	67.09%
	7/28/2023 17:00	7	28	16	9/5/2023 17:00	9	5	16	8.93%	33.56%	7.05%	67.09%	58.37%	54.69%	75.74%	71.95%
	9/5/2023 16:00	9	5	15	9/6/2023 18:00	9	6	17	53.32%	7.45%	75.78%	14.00%	60.48%	62.28%	75.78%	74.09%
	9/6/2023 16:00	9	6	15	9/7/2023 13:00	9	7	12	39.09%	40.72%	52.35%	38.81%	60.49%	73.00%	78.14%	74.18%
2024	6/21/2024 17:00	6	21	16	1/17/2024 8:00	1	17	8	41.21%	1.74%	69.47%	1.67%	66.75%	74.42%	78.49%	75.27%
	7/15/2024 17:00	7	15	16	7/9/2024 14:00	7	9	13	15.65%	33.90%	13.94%	33.62%	70.79%	76.25%	79.91%	76.86%
	7/16/2024 17:00	7	16	16	7/10/2024 16:00	7	10	15	34.21%	37.85%	50.38%	41.97%	71.28%	76.25%	81.01%	76.86%
	8/1/2024 17:00	8	1	16	7/15/2024 17:00	7	15	16	40.80%	15.65%	71.23%	13.94%	71.70%	77.42%	81.03%	78.37%
	8/28/2024 17:00	8	28	16	7/16/2024 15:00	7	16	14	7.78%	32.32%	6.26%	31.58%	72.26%	81.99%	82.21%	80.85%

Average Output on Peak	38.51%	26.10%	50.74%	30.83%
Max Output on Peak	72.26%	81.99%	82.21%	80.85%
Min Output on Peak	2.27%	0.00%	1.67%	0.00%
# <10%	7	23	8	22
# 10-20%	3	1	3	2
# 20-30%	7	3	2	1
# 30-40%	10	7	3	5
# 40-50%	4	7	5	3
# 50-60%	12	2	2	3
# 60-70%	3	1	9	6
# 70-80%	4	5	15	7
# 80-90%	0	1	3	1
# 90-100%	0	0	0	0
# >100 %	0	0	0	0

REVISED

Coincidence Analysis EPT SAM

SEIA Analysis using year-specific weather

SP-II-5 ATTACHMENT B (REV)

	PLC					NSPL					400kW Roof SPV		3MW Tracking SPV		Sorted			
	Hour Beginning EPT	Year	Mo	Day	Hr	Hour Beginning EPT	Year	Mo	Day	Hr	% Nameplate Production on PLC	% Nameplate Production on NSPL	% Nameplate Production on PLC	% Nameplate Production on NSPL				
2015	7/28/2015 16:00	2015	7	28	16	1/8/2015 7:00	2015	1	8	7	56.93%	0.00%	84.57%	0.00%	1.28%	0.00%	1.05%	0.00%
	7/20/2015 16:00	2015	7	20	16	2/16/2015 8:00	2015	2	16	8	48.60%	18.97%	67.51%	23.75%	8.50%	0.00%	8.95%	0.00%
	7/29/2015 16:00	2015	7	29	16	2/19/2015 19:00	2015	2	19	19	55.06%	0.00%	80.51%	0.00%	15.59%	0.00%	22.24%	0.00%
	9/3/2015 16:00	2015	9	3	16	2/20/2015 8:00	2015	2	20	8	41.60%	45.24%	56.61%	85.53%	23.75%	0.00%	30.50%	0.00%
	8/17/2015 14:00	2015	8	17	14	2/24/2015 7:00	2015	2	24	7	60.16%	14.49%	64.93%	33.65%	27.61%	0.00%	38.35%	0.00%
	7/25/2016 15:00	2016	7	25	15	1/19/2016 7:00	2016	1	19	7	56.77%	0.00%	66.86%	0.00%	27.70%	0.00%	43.79%	0.00%
2016	7/27/2016 16:00	2016	7	27	16	7/14/2016 16:00	2016	7	14	16	57.14%	57.42%	84.68%	85.23%	30.61%	0.00%	46.37%	0.00%
	8/10/2016 16:00	2016	8	10	16	7/25/2016 13:00	2016	7	25	13	37.38%	64.15%	47.17%	68.05%	31.13%	0.00%	47.17%	0.00%
	8/11/2016 15:00	2016	8	11	15	8/11/2016 14:00	2016	8	11	14	49.81%	73.01%	56.49%	79.87%	31.23%	0.00%	50.14%	0.00%
	8/12/2016 15:00	2016	8	12	15	9/8/2016 16:00	2016	9	8	16	59.38%	41.26%	72.48%	59.43%	33.07%	0.00%	50.64%	0.00%
	6/12/2017 17:00	2017	6	12	17	12/15/2016 18:00	2016	12	15	18	37.88%	0.00%	67.01%	0.00%	33.28%	0.00%	50.73%	0.00%
	6/13/2017 16:00	2017	6	13	16	12/16/2016 7:00	2016	12	16	7	41.83%	0.00%	52.17%	0.00%	33.85%	0.00%	52.17%	0.00%
2017	7/19/2017 17:00	2017	7	19	17	12/20/2016 7:00	2016	12	20	7	33.28%	0.00%	50.14%	0.00%	34.36%	0.00%	53.62%	0.00%
	7/20/2017 16:00	2017	7	20	16	1/9/2017 8:00	2017	1	9	8	48.17%	4.93%	64.49%	5.17%	34.95%	0.00%	56.49%	0.00%
	7/21/2017 16:00	2017	7	21	16	1/10/2017 7:00	2017	1	10	7	51.17%	0.00%	72.35%	0.00%	36.15%	0.09%	56.61%	0.03%
	8/28/2018 17:00	2018	8	28	17	1/3/2018 7:00	2018	1	3	7	33.85%	0.00%	69.15%	0.00%	36.33%	0.48%	57.71%	0.36%
	9/4/2018 17:00	2018	9	4	17	1/4/2018 19:00	2018	1	4	19	31.23%	0.00%	66.77%	0.00%	36.56%	1.42%	58.91%	0.79%
2018	6/18/2018 17:00	2018	6	18	17	1/5/2018 17:00	2018	1	5	17	8.50%	0.00%	8.95%	0.00%	37.38%	4.93%	59.33%	5.17%
	9/5/2018 17:00	2018	9	5	17	7/2/2018 16:00	2018	7	2	16	31.13%	55.08%	66.51%	81.85%	37.88%	9.97%	64.26%	23.75%
	8/27/2018 17:00	2018	8	27	17	8/29/2018 16:00	2018	8	29	16	27.70%	51.97%	46.37%	78.77%	38.69%	14.49%	64.49%	24.63%
	7/10/2019 17:00	2019	7	10	17	1/22/2019 7:00	2019	1	22	7	41.37%	0.00%	77.41%	0.00%	39.58%	18.97%	64.93%	32.47%
	7/17/2019 16:00	2019	7	17	16	1/30/2019 18:00	2019	1	30	18	1.28%	0.00%	1.05%	0.00%	40.55%	21.91%	66.51%	33.65%
2019	7/19/2019 17:00	2019	7	19	17	1/31/2019 7:00	2019	1	31	7	40.75%	0.48%	76.97%	0.36%	40.60%	23.17%	66.70%	34.95%
	7/29/2019 16:00	2019	7	29	16	2/1/2019 7:00	2019	2	1	7	40.55%	0.09%	50.73%	0.03%	40.68%	26.11%	66.77%	38.61%
	8/19/2019 16:00	2019	8	19	16	7/19/2019 16:00	2019	7	19	16	54.09%	55.72%	81.33%	82.06%	40.75%	26.20%	66.86%	40.68%
	7/6/2020 14:00	2020	7	6	14	7/20/2020 17:00	2020	7	20	17	67.74%	42.25%	76.08%	81.17%	41.03%	30.18%	67.01%	42.66%
2020	7/9/2020 17:00	2020	7	9	17	7/22/2020 14:00	2020	7	22	14	40.68%	30.18%	76.19%	32.47%	41.37%	35.20%	67.51%	43.37%
	7/20/2020 16:00	2020	7	20	16	7/27/2020 17:00	2020	7	27	17	57.50%	40.23%	85.31%	76.89%	41.49%	36.15%	69.15%	46.29%
	7/27/2020 16:00	2020	7	27	16	8/10/2020 17:00	2020	8	10	17	56.03%	38.23%	83.28%	73.74%	41.60%	36.56%	72.35%	47.06%
	7/29/2020 17:00	2020	7	29	17	8/11/2020 14:00	2020	8	11	14	39.58%	60.34%	74.53%	65.27%	41.83%	37.96%	72.48%	47.11%
	6/29/2021 16:00	2021	6	29	16	6/28/2021 17:00	2021	6	28	17	47.05%	39.94%	66.70%	76.22%	47.05%	38.23%	73.59%	59.43%
2021	7/6/2021 16:00	2021	7	6	16	6/29/2021 17:00	2021	6	29	17	27.61%	36.15%	30.50%	62.37%	48.17%	39.94%	73.60%	62.37%
	8/12/2021 16:00	2021	8	12	16	6/30/2021 15:00	2021	6	30	15	52.47%	40.75%	78.11%	47.06%	48.28%	40.23%	74.53%	63.83%
	8/24/2021 17:00	2021	8	24	17	8/12/2021 14:00	2021	8	12	14	36.33%	40.76%	74.57%	43.37%	48.60%	40.75%	74.57%	64.26%
	8/26/2021 15:00	2021	8	26	15	8/26/2021 16:00	2021	8	26	16	63.23%	50.67%	78.00%	76.62%	49.56%	40.76%	76.08%	65.27%
	7/20/2022 17:00	2022	7	20	17	1/27/2022 7:00	2022	1	27	7	41.03%	1.42%	77.67%	0.79%	49.81%	41.26%	76.19%	65.69%
2022	7/21/2022 16:00	2022	7	21	16	1/31/2022 8:00	2022	1	31	8	51.05%	21.91%	73.59%	34.95%	51.05%	42.25%	76.68%	68.05%
	7/22/2022 17:00	2022	7	22	17	8/4/2022 14:00	2022	8	4	14	34.36%	37.96%	58.91%	40.68%	51.17%	45.24%	76.97%	72.01%
	8/3/2022 17:00	2022	8	3	17	8/8/2022 16:00	2022	8	8	16	40.60%	51.83%	78.52%	76.18%	52.47%	50.67%	77.41%	73.74%
	8/8/2022 15:00	2022	8	8	15	8/9/2022 14:00	2022	8	9	14	38.69%	23.17%	43.79%	24.63%	54.09%	51.83%	77.67%	76.18%
	7/5/2023 17:00	2023	7	5	17	12/23/2022 18:00	2022	12	23	18	41.49%	0.00%	78.77%	0.00%	55.06%	51.97%	78.00%	76.22%
	7/27/2023 17:00	2023	7	27	17	2/3/2023 19:00	2023	2	3	19	30.61%	0.00%	50.64%	0.00%	56.03%	55.08%	78.11%	76.62%
2023	7/28/2023 17:00	2023	7	28	17	9/5/2023 17:00	2023	9	5	17	33.07%	26.20%	53.62%	47.11%	56.77%	55.16%	78.52%	76.89%
	9/5/2023 16:00	2023	9	5	16	9/6/2023 18:00	2023	9	6	18	48.28%	9.97%	73.60%	38.61%	56.93%	55.72%	78.77%	78.77%
	9/6/2023 16:00	2023	9	6	16	9/7/2023 13:00	2023	9	7	13	49.56%	73.34%	76.68%	72.01%	57.14%	57.42%	80.51%	79.87%
	6/21/2024 17:00	2024	6	21	17	1/17/2024 8:00	2024	1	17	8	34.95%	26.11%	57.71%	42.66%	57.50%	57.56%	81.33%	81.17%
2024	7/15/2024 17:00	2024	7	15	17	7/9/2024 14:00	2024	7	9	14	36.56%	57.56%	64.26%	63.83%	59.38%	60.34%	83.28%	81.85%
	7/16/2024 17:00	2024	7	16	17	7/10/2024 16:00	2024	7	10	16	36.15%	35.20%	59.33%	46.29%	60.16%	64.15%	84.57%	82.06%
	8/1/2024 17:00	2024	8	1	17	7/15/2024 17:00	2024	7	15	17	15.59%	36.56%	22.24%	64.26%	63.23%	73.01%	84.68%	85.23%
	8/28/2024 17:00	2024	8	28	17	7/16/2024 15:00	2024	7	16	15	23.75%	55.16%	38.35%	65.69%	67.74%	73.34%	85.31%	85.53%

Average Output on Peak	41.79%	27.17%	63.28%	38.73%
Avg Output on Peak 2020-2024	41.76%	35.04%	65.24%	50.11%
Max Output on Peak	67.74%	73.34%	85.31%	85.53%
Min Output on Peak	1.28%	0.00%	1.05%	0.00%
# <10%	2	19	2	18
# 10-20%	1	2	0	0
# 20-30%	3	4	1	2
# 30-40%	15	7	2	4
# 40-50%	15	6	3	6
# 50-60%	11	8	10	1
# 60-70%	3	2	10	6
# 70-80%	0	2	16	8
# 80-90%	0	0	6	5
# 90-100%	0	0	0	0
# >100 %	0	0	0	0

REVISED

400kWAC Roof SPV

SP-II-5 ATTACHMENT B (REV)

PVWatts Hourly PV Performance Data	
Requested Location	17837, USA
Location	Lat, Lng: 40.97, -76.9
Latitude (DD)	40.97
Longitude (DD)	-76.9
Elevation (m)	143.25
DC System Size (kW)	480
Module Type	Standard
Array Type	Fixed (roof mount)
Array Tilt (deg)	20
Array Azimuth (deg)	180
System Losses (%)	14.08
DC to AC Size Ratio	1.2
Inverter Efficiency (%)	96
Ground Coverage Ratio	NA
Albedo	From weather file
Bifacial	No (0)
Monthly Irradiance Loss (%)	

Jan	0
Feb	0
Mar	0
Apr	0
May	0
June	0
July	0
Aug	0
Sept	0
Oct	0
Nov	0
Dec	0

Annual Capacity Factor	16.69%

Month	Day	Hour	Beam Irradiance (W/m2)	Diffuse Irradiance (W/m2)	Ambient Temperature (C)	Wind Speed (m/s)	Albedo	Plane of Array Irradiance (W/m2)	Cell Temperature (C)	DC Array Output (W)	AC System Output (W)
1	1	0	0	0	-2	0.3	0.87	0	-2	0	0
1	1	1	0	0	-2	0.3	0.87	0	-2	0	0
1	1	2	0	0	-3	0.3	0.87	0	-3	0	0
1	1	3	0	0	-3	0.2	0.87	0	-3	0	0
1	1	4	0	0	-4	0.2	0.87	0	-4	0	0
1	1	5	0	0	-4	0.2	0.87	0	-4	0	0
1	1	6	0	0	-5	0.2	0.87	0	-5	0	0
1	1	7	0	0	-4	0.2	0.87	0	-4	0	0
1	1	8	0	17	-2	0.2	0.87	16.439	-1.276	6425.93	4295.723
1	1	9	0	42	0	0.3	0.87	40.685	1.75	16797.473	14299.761
1	1	10	0	85	0	0.3	0.87	83.479	3.59	35113.113	31966.406
1	1	11	0	134	0	0.4	0.87	135.413	5.645	57281.178	53348.968
1	1	12	2	148	0	0.4	0.87	152.186	6.344	64432.094	60246.499
1	1	13	0	135	0	0.4	0.87	137.528	5.736	58298.772	54330.505
1	1	14	0	38	-1	0.3	0.87	36.801	0.583	15215.7	12774.037
1	1	15	0	40	-1	0.3	0.87	38.758	0.663	15876.341	13411.269
1	1	16	0	6	-2	0.3	0.87	5.796	-1.786	1444.066	0
1	1	17	0	0	-3	0.2	0.87	0	-3	0	0
1	1	18	0	0	-5	0.2	0.87	0	-5	0	0
1	1	19	0	0	-6	0.2	0.87	0	-6	0	0
1	1	20	0	0	-6	0.2	0.87	0	-6	0	0
1	1	21	0	0	-8	0.2	0.87	0	-8	0	0
1	1	22	0	0	-10	0.4	0.87	0	-10	0	0
1	1	23	0	0	-12	0.5	0.87	0	-12	0	0

REVISED

3MW Tracking SPV

SP-II-5 ATTACHMENT B (REV)

PVWatts Hourly PV Performance Data

Requested Location	17837, USA
Location	Lat, Lng: 40.97, -76.9
Latitude (DD)	40.97
Longitude (DD)	-76.9
Elevation (m)	143.25
DC System Size (kW)	3600
Module Type	Premium
Array Type	1-Axis Backtracking
Array Tilt (deg)	0
Array Azimuth (deg)	180
System Losses (%)	14.08
DC to AC Size Ratio	1.2
Inverter Efficiency (%)	96
Ground Coverage Ratio	96
Albedo	From weather file
Bifacial	No (0)
Monthly Irradiance Loss (%)	

Jan	0
Feb	0
Mar	0
Apr	0
May	0
June	0
July	0
Aug	0
Sept	0
Oct	0
Nov	0
Dec	0

Annual Capacity Factor	18.79%

Month	Day	Hour	Beam Irradiance (W/m2)	Diffuse Irradiance (W/m2)	Ambient Temperature (C)	Wind Speed (m/s)	Albedo	Plane of Array Irradiance (W/m2)	Cell Temperature (C)	DC Array Output (W)	AC System Output (W)
1	1	0	0	0	-2	0.3	0.87	0	-2	0	0
1	1	1	0	0	-2	0.3	0.87	0	-2	0	0
1	1	2	0	0	-3	0.3	0.87	0	-3	0	0
1	1	3	0	0	-3	0.2	0.87	0	-3	0	0
1	1	4	0	0	-4	0.2	0.87	0	-4	0	0
1	1	5	0	0	-4	0.2	0.87	0	-4	0	0
1	1	6	0	0	-5	0.2	0.87	0	-5	0	0
1	1	7	0	0	-4	0.2	0.87	0	-4	0	0
1	1	8	0	17	-2	0.2	0.87	16.222	-1.393	46892.126	30961.726
1	1	9	0	42	0	0.3	0.87	34.789	1.273	105652.165	87639.664
1	1	10	0	85	0	0.3	0.87	71.466	2.615	221571.736	199451.744
1	1	11	0	134	0	0.4	0.87	127.218	4.512	398482.056	370093.427
1	1	12	2	148	0	0.4	0.87	146.309	5.188	458761.162	428236.605
1	1	13	0	135	0	0.4	0.87	120.391	4.272	377429.743	349787.081
1	1	14	0	38	-1	0.3	0.87	31.458	0.152	95649.486	77991.419
1	1	15	0	40	-1	0.3	0.87	36.648	0.338	110827.321	92631.444
1	1	16	0	6	-2	0.3	0.87	5.946	-1.816	10975.406	0
1	1	17	0	0	-3	0.2	0.87	0	-3	0	0
1	1	18	0	0	-5	0.2	0.87	0	-5	0	0
1	1	19	0	0	-6	0.2	0.87	0	-6	0	0
1	1	20	0	0	-6	0.2	0.87	0	-6	0	0
1	1	21	0	0	-8	0.2	0.87	0	-8	0	0
1	1	22	0	0	-10	0.4	0.87	0	-10	0	0
1	1	23	0	0	-12	0.5	0.87	0	-12	0	0

REVISED

EXHIBIT KL-18

REVISED

CITIZENS' ELECTRIC COMPANY OF LEWISBURG, PA
DOCKET NO. R-2025-3054394

OCA-XV-1

Please refer to "Attachment A (Rev)" of Citizens' response to SP-II-5, specifically in the portion that states: "PJM costs substantially unaffected by net metered sales." Please explain the effect of net metered sales on PJM costs.

Response Provided By:
Nathan Johnson, President & Chief Executive Officer, Citizens' Electric Company of Lewisburg, PA

Date: August 4, 2025

Response:

The net effect of net-metered sales on PJM costs is better explained by SP-II-5 Attachment B which examines the coincidence of the output of two different hypothetical solar arrays with the Company's historical PJM peak hours for the past ten years. This analysis demonstrates both the low coincidence and high volatility of solar output with respect to peak hours. The company discounts potential savings in PJM Capacity and Transmission costs resulting from net-metered generation because:

1) Net-metered generation cannot be dispatched and is not required or incentivized to export during peak demand periods unless the energy crediting mechanism is the real-time locational marginal price (or another time-differentiated rate that accurately reflects real time conditions).

2) Beyond the lack of incentive to export during peak periods, GSSR-1 customer-generators that produce more than they consume on an annual basis actually benefit from high capacity and transmission prices that inflate the PTC rate they are reimbursed at, which disincentivizes participation during peak demand periods.

3) Net-metered generation, solar in particular, has a low demonstrated coincidence with peak demand periods.

4) Net-metered generation output during peak demand periods is highly volatile because of the influence of weather, seasonal availability, and the variation in seasons, days and times at which peaks occur.

REVISED

EXHIBIT KL-19

REVISED

CITIZENS' ELECTRIC COMPANY OF LEWISBURG, PA
DOCKET NO. R-2025-3054394

OCA-XV-2

Please refer to "Attachment B (Rev)" of Citizens' response to SP-II-5, specifically the Average Output on Peak of 25.36%. Does this net metered generation reduce the load obligation driving PJM costs? If yes, how should this load reduction be incorporated in the analysis in response to SP-II-5?

Response Provided By:
Nathan Johnson, President & Chief Executive Officer, Citizens' Electric Company of Lewisburg, PA

Date: August 4, 2025

Response:

Please see the Company's response to OCA-XV-1. The on Peak Output of net-metered generation may reduce load that determines the PJM obligations determining PJM costs. The Company does not believe it is appropriate to incorporate any capacity or transmission impact into its analysis, however, because net-metered generation does not guarantee those savings and is economically disincentivized to export during peak demand periods. Please note that a customer generator on the GSSR-2 rate would see the benefit of a zero transmission and/or capacity obligation if it successfully offsets its on-site consumption during the relevant PJM peaks.

REVISED

CITIZENS' ELECTRIC COMPANY OF LEWISBURG, PA
DOCKET NO. R-2025-3054394

SP-VI-17

Please explain excess generation exported from a behind-the-meter generator onto the Company's distribution system affects the Default Service Provider's supply obligation and the associated PJM settlement processes. In particular, please explain how excess generation from net metering customers affects the Load-Following Full Requirements contract(s) between the Company and it's Default Service Provider(s). To the extent that the answer varies between the GSSR-1 and GSSR-2 rate schedules, please discuss.

Response Provided By:
Nathan Johnson, President & Chief Executive Officer, Citizens' Electric Company of Lewisburg, PA

Date: August 25, 2025

Response:

The Company is the Default Service Provider in its territory. As explained in the Company's response to SP-VI-16, net-metered generation reduces the load delivered by Citizens' wholesale supplier at the delivery point, reducing the total MWh that the wholesale supplier is responsible to procure for the Company. The wholesale supplier schedules anticipated hourly default service load through the PJM scheduling process on a day-ahead basis. This day-ahead schedule is subsequently reconciled against actual volumes for Citizens' default service customers. The reconciliation includes multiple components. First, the total hourly metered values at the Citizens' Aggregate Bus are reduced by the metered volumes (plus distribution losses) for accounts that are served by Electric Generation Suppliers ("EGSs"). Second, Citizens' must account for any hourly energy exports from the Bucknell University Qualifying Facility under the Public Utility Regulatory Policies Act ("PURPA"). Finally, Citizens' uses hourly default service account metered usage to segregate the amounts between the GSSR-1 and GSSR-2 classifications.

REVISED

EXHIBIT KL-20

REVISED

CITIZENS' ELECTRIC COMPANY OF LEWISBURG, PA
DOCKET NO. R-2025-3054394

SP-VI-17

Please explain excess generation exported from a behind-the-meter generator onto the Company's distribution system affects the Default Service Provider's supply obligation and the associated PJM settlement processes. In particular, please explain how excess generation from net metering customers affects the Load-Following Full Requirements contract(s) between the Company and it's Default Service Provider(s). To the extent that the answer varies between the GSSR-1 and GSSR-2 rate schedules, please discuss.

Response Provided By:
Nathan Johnson, President & Chief Executive Officer, Citizens' Electric Company of Lewisburg, PA

Date: August 25, 2025

Response:

The Company is the Default Service Provider in its territory. As explained in the Company's response to SP-VI-16, net-metered generation reduces the load delivered by Citizens' wholesale supplier at the delivery point, reducing the total MWh that the wholesale supplier is responsible to procure for the Company. The wholesale supplier schedules anticipated hourly default service load through the PJM scheduling process on a day-ahead basis. This day-ahead schedule is subsequently reconciled against actual volumes for Citizens' default service customers. The reconciliation includes multiple components. First, the total hourly metered values at the Citizens' Aggregate Bus are reduced by the metered volumes (plus distribution losses) for accounts that are served by Electric Generation Suppliers ("EGSs"). Second, Citizens' must account for any hourly energy exports from the Bucknell University Qualifying Facility under the Public Utility Regulatory Policies Act ("PURPA"). Finally, Citizens' uses hourly default service account metered usage to segregate the amounts between the GSSR-1 and GSSR-2 classifications.

REVISED

EXHIBIT KL-21

REVISED

CITIZENS' ELECTRIC COMPANY OF LEWISBURG, PA
DOCKET NO. R-2025-3054394

SP-IV-13

Please provide the annual number of customers currently eligible for net metering, and the total exported kWh credited at retail rates, for each of the past three (3) years.

Response Provided By:
Nathan Johnson, President & Chief Executive Officer, Citizens' Electric Company of Lewisburg, PA

Date: August 25, 2025

Response:

The request, as stated, would be burdensome and irrelevant to proposals discussed in rebuttal testimony. The Company, instead, provides a 3-yr analysis of all monthly exports and energy-year-end credits provided to customer-generators.

The Table below provides the requested data for the most recent three available energy-years. Please note that the column titled "Total Monthly Net Exports" is the sum of all months for which a customer in that class *added* kWh to their bank. It does not account for hourly exports later consumed within the same billing period.

Year	Class	# Eligible	# Annual Exporters	Total Monthly Net Exports	EOY Banked kWh
2025	Res	73	41	337,834	60,556
2025	Comm/Ind	15	10	2,608,160	577,510
2024	Res	64	34	106,629	60,709
2024	Comm/Ind	13	8	2,260,521	372,980
2023	Res	51	23	51,625	36,133
2023	Comm/Ind	9	6	768,371	290,821

REVISED

EXHIBIT KL-22

REVISED

Pa. PUC v. Citizens' Electric Company
Docket Nos. R-2025-3054394

Interrogatories of Kelly Road Solar, LLC, Lancaster Avenue Solar, LLC, and Twilight Renewables, LLC (Solar Projects)
OCA Response to Solar Projects Set I

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1. Please refer to OCA Statement 5R at 6, which contains a summary of the Company's argument as to why its proposed Billing Demand proposal is reasonable. Does OCA have an independent perspective of whether the Company's Billing Demand proposal is reasonable? If so, please provide OCA's perspective on this proposal.

In the recent UGI Electric Order[1], one of the contested issues involved a proposed methodology for assigning customers to different rates based upon supply peak load impact (SPLI).
In my opinion, the methodology approved by the PUC in the UGI Electric Order is generally similar to Citizens' proposal in this proceeding. In the UGI Electric Order, the Commission accepted UGI's reasoning that the "approach [would] better align larger net-metering customer-generators with larger customers that have similar grid impacts."[2] In my analysis of Citizens' proposal, I found the methodology to be reasonable for a similar reason, as it would ensure that the overall default service construct, including its rates and rate classification, would be designed efficiently. I addressed this in pages 9-10 of my rebuttal testimony.

2. Please refer to OCA Statement 5R at 9, which contains a summary of the Company's analysis performed in SP-II-5 Attachment A. Has OCA independently validated the quantitative approach used by the Company in this analysis? If so, did it find any deficiencies in the analysis or did it reach the same conclusion as the Company?

While I reviewed and evaluated the quantitative approach presented in SP-II-5 Attachment A, I did not independently validate the quantitative approach by reconciling/cross-checking monetary values and magnitude of costs. Based on my evaluation, the quantitative approach appears sensible, and I did not find the analysis to be deficient. Therefore, I found the direction of the conclusion in SP-II-5 Attachment A (cost comparison/deviation driven by "PJM costs [which would be] substantially unaffected by net metered sales") to be sensible.

3. Please refer to OCA Statement 5R at 12, which states "I take this statement to mean that the large customer-generator (output capacity > 400 kW) stands to benefit from higher prices caused by the risk premiums added to DSP suppliers to address their risks caused by unknown output quantities and attrition risk of large customer-generators."

   a. What is the basis for this assumption, and is it supported by any discovery responses

[1] *Petition of UGI Utilities, Inc-Electric Division for Approval of a Default Service Plan for the Period of June 1, 2025 though May 31, 2029*¸ Docket No. P-2024-3049343, et al (*UGI Electric Order*).
[2] UGI Electric Order, p. 4

provided by the Company?

My assumption is based on two documents.

First, see the following description of UGI's argument in the UGI Electric Order, p. 23:

> The Company determined that if large customer-generators were to be included in the GSR-1 group, then: (1) their output would decrease GSR-1 group load and tranche size; (2) there is substantial question as to the level of output and timing of when these projects will become operational; and (3) these large customer-generators have the ability to leave default service at any time and participate in the wholesale market, thereby creating an attrition risk if projects opt to leave GSR-1 service and shop their output elsewhere. UGI argued that each of these factors would substantially increase risk for wholesale suppliers, causing higher bid premiums and likely reducing the number of competitive bidders.[3]

Second, the response from Citizens to SP-II-5 provides:

> Additionally, while no quantitative analysis has been performed, basic market principles suggest that as the total volume of energy purchased decreases, the price-per-unit will increase. In essence, as more energy is purchased from net-metered exports, less is purchased through the DSP wholesale contract. This lowers the 'buying power' of the DSP while concentrating non-volumetric (Company and supplier admin costs, Capacity, Transmission, and RTEP) costs across a smaller total quantity purchased, increasing the cost per MWh of default supply.
>
> Finally, as purchased net-metered energy creates net under collection of GSSR costs under the existing structure (where the customer generator receives the GSSR-1 price regardless of the generator's size), the resulting reconciliation in future periods through the E-factor inflates the cost of default supply which, in turn, inflates the purchased cost of future-period net-metered energy purchases. In short, net-metered customer-generators directly benefit from the price inflation that they cause in a compounding fashion that increases as more net-metered generation is installed.[4]

The above passages informed my assumption. In the Company's response above, the Company concludes their discussion of uncertainty and market principles by noting "price inflation" after a detailed outline of the cause and effect of under-collection driven by purchased net-metered energy. Given this, I found the statement to be generally comparable to the "bid premium" discussion in the UGI Electric Order.

[3] PA PUC Opinion and Order, p. 23
[4] Citizens' Response to SP-II-5, p. 2

b. Has OCA performed any analysis or research on whether suppliers have included an additional risk premium in their bids when participating in the default service procurement auctions? If so, please provide all such analysis or research.

No, for the following reasons: (1) the OCA is not permitted to see bid details such as these following the completion of default service procurement auctions; and (2) given this lack of information, no further analysis on risk premiums was performed. A qualitative evaluation is provided in my testimony.

4. Please refer to OCA Statement 5R at 15, which states "Mr. Nolt may be overstating the impact of the proposed Billing Demand methodology on customer-generator compensation."

a. Is OCA disputing the calculations that Mr. Nolt provided in his testimony, or does this sentence refer to the lack of clarity on how the Company will compensate customer-generators for excess generation? If the former, please provide all analysis that OCA performed disputing Mr. Nolt's calculations.

This sentence refers to the latter: the lack of clarity on how the Company will compensate customer-generators for excess generation.

5. Please refer to OCA Statement 5R at 16, lines 7-11, discussing the proposed Billing Demand methodology's impact on residential customers with DER.

a. Does OCA believe that commercial customers with behind-the-meter DERs could be impacted by the Company's Billing Demand proposal?

Yes, commercial customers with behind-the-meter DERs could be impacted depending on the output capacity of their DER.

b. If the answer to a) is yes, please provide OCA's position on the impact of the Company's proposed Billing Demand methodology on commercial customers with DERs.

I believe that the Company's Billing Demand proposal could be impactful to these commercial customers. Some customers will be deemed GLP-1 based on the buildings on their premises and might be applied the GSSR-2 rate based on their electricity usage or if the output capacity of their associated DER is greater than 400 kW. If this is the case, aligning the management of supply for this block of larger retail customers alongside a block of larger customer generators should be more

BEFORE

THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	**:**	
	:	
v.	**:**	**Docket No. R-2025-_____**
	:	
Citizens' Electric Company of Lewisburg, PA	**:**	

DIRECT TESTIMONY

AND EXHIBITS

OF

HOWARD S. GORMAN

ON BEHALF OF

CITIZENS' ELECTRIC COMPANY OF LEWISBURG, PA

APRIL 30, 2025

BEFORE

THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	**:**	
	:	
v.	**:**	**Docket No. R-2025-_____**
	:	
Citizens' Electric Company of Lewisburg, PA	**:**	

DIRECT TESTIMONY OF HOWARD S. GORMAN
ON BEHALF OF CITIZENS' ELECTRIC COMPANY OF LEWISBURG, PA

Q. Please state your name, occupation and business address.

A. My name is Howard Gorman. I am the President of HSG Group, Inc., a consulting firm specializing in utility rate and regulatory matters, located in Great Neck, NY.

Q. Please summarize your educational background and professional experience.

A. My educational background, professional experience and summary of testimony are outlined in Attachment A.

Q. Please state on whose behalf you are testifying and describe the purposes of your testimony.

A. I am testifying on behalf of the petitioner, Citizens' Electric Company of Lewisburg, PA ("Citizens'" or "Company"). The purposes of my testimony are:

- To develop the Fully Projected Future Test Year ("FPFTY") Revenue Requirement and Rate Base, and Future Test Year ("FTY") net income, based on Historic Test Year ("HTY") data and appropriate adjustments;
- To present the allocated class cost of service study that I performed; and

- To present the Company's proposed revenue allocation and the proposed Rates and Charges that produce the overall revenue requirement and the class revenue targets, and the proof of revenue and bill comparisons at the proposed rates.

The rates proposed in this filing are for the FPFTY; the FPFTY Revenue Requirement and Rate Base were determined for distribution only. Revenue and costs related to Citizens' Generation Supply Service Rate ("GSSR") were excluded from the analysis.

References in my testimony are to *Exhibit __ (HSG-1)*; for example, *Schedule C1* refers to *Exhibit __ (HSG-1), Schedule C1*.

In my testimony, dollar amounts (excluding rates and charges) are rounded to the nearest thousand dollars; in computing revenue requirements and rates, whole dollars are used.

Q. What FPFTY, FTY and HTY were used?

A. The HTY is Citizens' actual results for calendar year 2024. The FTY is Citizens' forecast for 2025 and the FPFTY is Citizens' forecast for 2026. Citizens' uses a calendar year for financial reporting.

When will the new rates take effect?

A. If the Commission suspends the filing for the statutory period, then the rates will take effect on January 30, 2026; however, the rate changes could be effective sooner if the Commission doesn't suspend the filing or if the parties reach a settlement that includes an accelerated effective date and that settlement is approved by the Commission.

Q. Is the presented FPFTY consistent with the Commission's revised regulations for rate cases using a FPFTY?

A. Yes. Earlier this year, the Commission adopted revised regulations for Sections 53.51-53.56 that are pending before the Independent Regulatory Review Commission, with final

action expected soon after the Company submits this filing. The revised regulations contain the following definition of FPFTY:

> A 12-consecutive-month period beginning with the first month that the new rates will be in effect after application of the full suspension period permitted under section 1308(d) of the Public Utility Code, 66 Pa.C.S. § 1308 (relating to voluntary changes in rates) and reflecting estimated results of operations of the public utility.

Q. Please summarize the results of your testimony regarding Citizens' revenue requirement.

A. Under its present rates, Citizens' is forecast to have Net operating income of approximately $250,000 in FPFTY 2026, a return on rate base of 1.46%. To produce the return of 8.49% that Company witnesses Mr. D'Ascendis and Mr. Kucan recommend, requires an increase in revenue of $1,795,000, an increase of 29.6% in Distribution revenue. This equals an increase in total revenue (distribution and supply) of 11% of Citizens' 2024 total revenue. The revenue produced by the proposed rates in the FPFTY, $7,849,000 (plus $104,000 Other revenue, for total distribution revenue of $7,953,000) would recover Citizens' forecast costs in the FPFTY, and provide return on rate base of 8.49% (Schedule C1).

Q. Please summarize the purpose and results of the allocated class cost of service study.

A. The purpose of an allocated class cost of service study ("ACOS") is to assign, on a cost-causation basis, the total distribution revenue requirement among the rate classes. The results of Citizens' ACOS are presented on Schedule E-1. This schedule shows, for each rate class, FPFTY net income at present rates (line 7), return on rate base at present rates (line 11), the revenue requirement to produce a return of 8.49% (line 13) and the increase or decrease in revenue to achieve the class revenue requirement (line 28). The Company

used the results of the ACOS to allocate the proposed increase among customer classes to move the classes closer to the cost-to-serve as indicated in the ACOS.

Q. Please summarize the proposed revenue allocation and rate design.

A. The Company's proposed revenue target for each class is presented on Schedule B6-4, line 24, and the proposed increases are on line 36. This schedule also presents other information about the increase, which I discuss later in this testimony.

The Company's proposed rates are presented on Schedule B6-3, lines 12-21, and also on Schedule B7. Schedule B6-3 demonstrates that the proposed rates produce the class revenue targets (compare lines 29 and 30; differences due to rounding).

Q. Please describe the approach used to develop Citizen's revenue requirement and proposed rates.

A. *First*, the FTY and FPFTY forecast of sales and distribution revenue was developed. Information about HTY sales and revenue was obtained from Citizens' financial records. Summary information on sales and revenues is presented in Schedule B. Information for HTY 2024 is on Schedule B1, with computations on Schedule B1-1. Schedule B4 presents a reconciliation of HTY 2024 revenue to Citizens' financial statements. Sales and revenue for FTY 2025 is on Schedule B2, with computations on Schedule B2-1. Sales and revenue for FPFTY 2026 is on Schedule B3, with computations on Schedule B3-1.

Second, costs were obtained for the HTY, and forecasted costs were obtained for the FTY and FPFTY. These costs, detailed by account, are presented on Schedule C1-1.

Third, the Rate Base for the HTY, FTY and FPFTY was developed, using information for the HTY, projected capital expenditures for the FTY and FPFTY and computing annual depreciation expense. In addition, accumulated deferred income taxes, cash working

capital allowance and other rate base components were computed. These computations are shown on Schedule C1-5.

Fourth, the required Net Utility Operating Income was developed using the FPFTY costs and rate base, and the required rate of return developed by Mr. D'Ascendis and Mr. Kucan, 8.49%. FPFTY revenue of $7,953,000 (including Other revenue) is needed to produce the 8.49% rate of return. These results are presented in Schedule C1, which also shows the rate of return for the HTY, FTY and FPFTY at present rates.

Fifth, the ACOS (presented in Schedule E) was performed to develop the share of the total revenue requirement attributable to each rate class.

Finally, proposed rates were developed that produce the required FPFTY revenue. The proposed rates are shown on Schedules B6-3 and B7. The amounts that typical ratepayers can expect to pay under the proposed rates are compared to the amounts they would pay under the present rates on Schedule B8 (including the present GSSR rate), Schedule B8-1 (excluding GSSR) and B8-2 (including the proposed GSSR rate effective June 1, 2025.). Schedule B6-3 demonstrates that the proposed rates produce the required revenue (compare lines 29 and 30).

Q. What are the reasons that Citizens' needs an increase in rates at this time?

A. Schedule C5-1 presents the financial drivers for the requested rate increase by comparing the FPFTY to the final results of Citizens' prior rate case, Docket R-2022-3032692. The increase is driven by increased costs and capital expenditures. The Company's internal witnesses will discuss this in more detail.

Q. What service classifications does Citizens' use to report sales and revenue?

A. Citizens' reports sales and revenue using the following service classifications:

Residential	• Schedule RS- Residential
Commercial and Industrial	• Schedule GLP1 – General Light and Power Service • Schedule GLP3 – General Light and Power Service • Schedule SH – Space Heating
Lighting	• Schedule MBL – Municipal Boulevard Lighting • Schedule OL – Outdoor Lighting

Q. What types of charges are in the current Tariff?

A. *Schedule RS* rates include a fixed monthly charge, a volumetric (kWh-based) distribution charge and the volumetric GSSR charge.

Schedule SH rates include a fixed monthly charge, a volumetric (kWh-based) distribution charge and the volumetric GSSR charge.

Schedule GLP-1 rates include a fixed monthly charge, a volumetric (kWh-based) distribution charge, a demand (kW-based) charge and the GSSR charge, which may be the GSSR-1 (volumetric) or the GSSR-2 (volumetric and demand components). The demand charge is the greater of 1) actual demand for the month based on the highest 15-minute interval and 2) 50% of the maximum billed demand in the previous 11 months.

Schedule GLP-3 rates include a fixed monthly charge, a volumetric distribution (kWh-based) charge, a demand (kW-based) charge and the GSSR charge, which may be the GSSR-1 (volumetric) or the GSSR-2 (volumetric and demand components). The volumetric distribution charge has two blocks, with the first block comprised of 30 kWh times the customer's billed demand for the month. The demand charge is the greater of 1) actual demand for the month based on the highest 15-minute interval and 2) 50% of the maximum billed demand in the previous 11 months. Some GLP-3 customers are also subject to a reservation charges and / or a high voltage discount.

Schedule MBL rates include fixed monthly charges based on the number of meters (installations) and the number of lamp posts, plus the volumetric GSSR charge.

Schedule OL rates are fixed monthly charges per lamp and the volumetric GSSR charge.

All customers are billed monthly.

Q. Is the Company proposing any rate structure changes?

A. No, the Company is not proposing any rate structure changes.

HTY INFORMATION

Q. Please identify and describe the exhibits that show HTY sales and revenue.

A. Schedule B shows total revenue by customer type for HTY 2024, and distribution-only revenue for HTY 2024, FTY 2025 and FPFTY 2026. HTY total revenue is $16,378,000 based on Citizens' financial records. The HTY distribution-only amounts equal the total revenue amounts minus GSSR revenue. The HTY total revenue amounts are from Schedule B1, which is supported by detailed computations on Schedule B1-1, using present rates and HTY billing units. The billing units are sales in kWh, numbers of customer bills and demand in kW.

Q. Please describe the HTY information regarding costs.

A. Schedule C1-1 shows the details of operating expenses for the HTY. This exhibit is described in detail later in my testimony.

Q. Please describe the HTY information regarding rate base and Rate of Return.

A. Schedule C1-5 computes the rate base for the HTY. Schedule C1 shows the return on rate base for the HTY 2024 was 5.27% for distribution-only.

FTY AND FPFTY SALES AND REVENUE

Q. Please identify and describe the exhibits that show FTY 2025 and FPFTY 2026 sales and revenue at present rates.

A. Information on sales and revenue is presented in Schedule B. The computation of revenue on these schedules reflects the rates in effect December 31, 2024. In this testimony, "sales" measures kWh delivered.

Information for HTY 2024 is on Schedule B1, with computations on Schedule B1-1. Sales were approximately 151 million kWh, with approximately 295,000 kW billed demand.

The FTY 2025 and FPFTY 2026 sales forecasts, including number of customers, kWh and kW demand, were developed separately for each rate class.

Schedule RS Residential reflects average kWh per customer over 2020-2024, times average number of customers in 2024, plus expected growth of 25 customers in FTY 2025 and another 25 in FPFTY 2026.

Schedule SH Space Heating reflects the class average kWh per customer over 2020-2024, with no change in number of customers.

Schedule GLP-1 reflect the class average kWh per customer over 2020-2024, with no change in number of customers and no change in billed demand.

Schedule GLP-3 reflects the class average kWh per customer over 2020-2024 for existing customers, plus expected growth of 1 customer in FTY 2025 with associated additions of kWh and billed demand, and no further changes in FPFTY 2026.

Schedules MBL and *OL* reflect the customers and usage in 2024; HPS lamps have been replaced with LED over the years, therefore 2024 usage is more representative of future usage than using the historic average.

Forecast FTY 2025 sales are approximately 161 million kWh (Schedule B2-1, line 51) and distribution revenue at present rates is $6,038,000 (Schedule B2-1, line 29).

Forecast FPFTY 2026 sales are approximately 162 million kWh (Schedule B3-1, line 53), and distribution revenue at present rates is $6,055,000 (Schedule B3-1, line 29).

FTY AND FPFTY COSTS

Q. Please list the types of costs included in FTY and FPFTY costs.

A. FTY and FPFTY costs include Operating and Maintenance costs ("O&M") and Non-operating costs. O&M costs include Purchased Electricity, Distribution expenses, Customer accounting and collection expenses and Administrative & General expenses. Non-operating costs include Depreciation expense, Taxes other than income and Income tax expense.

Q. How did you develop the FTY and FPFTY O&M costs?

A. HTY actual O&M costs, totaling $13,866,000, are summarized on Schedule C1, line 17. Schedule C1-1 shows the detail of O&M costs by account for 2023 and HTY 2024 (actual) and for FTY 2025 and FPFTY 2026 (forecast). The costs are carried forward to Schedule C1. Schedule C1-1, lines 41-46, presents a summary of costs by type (labor, overhead, transportation, materials).

The Labor portion of each O&M account is also shown on Schedule C1-1.

The HTY, FTY and FPFTY costs are summarized and carried forward to Schedule C1.

Q. How was Depreciation expense computed for each year?

A. Schedule C3, page 1, shows the asset values at original cost in PAPUC / FERC account detail as of December 31, 2023, actual additions and retirements in HTY 2024, and planned additions for FTY 2025 and FPFTY 2026.

Schedule C3, page 2, shows the depreciation rate applicable to each account, and depreciation expense for each year. The annual depreciation expense for each asset account was computed by multiplying X) the depreciation rate for the asset account times Y) original cost at prior year end plus one-half of the additions for the year. The total FPFTY depreciation expense, less the amount charged to clearing accounts and recovered in O&M costs, is $1,410,000; this amount is carried forward to Schedule C1.

Schedule C4 shows the Reserve for Depreciation at the ends of the HTY, FTY and FPFTY.

Q. How did you compute Taxes other than income for FTY 2025 and FPFTY 2026?

A. Schedule C1-3 shows the components of Taxes other than income.

The Pennsylvania Use Tax and the PUC Assessment are assumed to be the same in FTY and FPFTY as in HTY. The Public Utility Realty Tax is assumed to change in relation to Net plant. The Pennsylvania Gross Receipts Tax ("GRT") is computed by applying the tax rate of 5.90% to the applicable revenue for each year.[1] The FTY and FPFTY totals are carried forward to Schedule C1.

Q. How did you compute Rate case expense amortization?

A. Rate case expense amortization reflects normalized rate case expense. Expenses for the pending rate case, if fully litigated, are estimated at $327,000 and a three-year normalization period was determined to be reasonable, starting January 1, 2026 (the start of the FPFTY). The computation is shown on Schedule C1-3 and the result is carried forward to Schedule C1-1, Account 928 (line 34), Regulatory Commission Expense.

Q. How did you compute the FTY and FPFTY Income tax expense?

A. Income tax expense for the FTY and FPFTY is computed on Schedule C1-4.

[1] The effective tax rate is calculated using the 59 mills GRT.

Net operating income before income taxes (line 1), is from Schedule C1, line 25.

Synchronized interest expense (lines 3-8) is computed by multiplying rate base (Schedule C1, line 30) by the weighted cost of debt (Schedule C1-2).

Taxable income before depreciation tax adjustments (line 9) is equal to Net operating income before income taxes less Synchronized interest expense.

Regulatory Pennsylvania taxable income and Regulatory Pennsylvania tax expense are computed using the Full flow through method; that is, tax depreciation is used in the computation. The Pennsylvania depreciation adjustment (lines 11-14) reflects the depreciation expense on Citizens' Pennsylvania tax return and is computed using the double declining balance method applied to tax basis and tax life (just as on the tax return). Regulatory Pennsylvania taxable income (line 15) is equal to Taxable income before depreciation tax adjustments as adjusted by the Pennsylvania depreciation adjustment. Regulatory Pennsylvania income tax expense (line 16) is equal to Regulatory Pennsylvania taxable income times the statutory 9.99% rate.

Regulatory Federal taxable income and Regulatory Federal tax expense are computed using a modified Full flow through method; that is, a modified tax depreciation amount is used in the computation. The Federal depreciation adjustment (lines 19-21), reflects straight line depreciation applied to tax basis and tax life. Federal taxable income (line 26) is equal to Taxable income before depreciation tax adjustments as adjusted by the Federal depreciation adjustment and less Regulatory Pennsylvania tax expense. Regulatory Federal income tax (line 27) is equal to Regulatory Federal taxable income times the statutory 21% rate.

Regulatory Total income tax expense (line 29) is equal to Regulatory Pennsylvania income tax expense plus Regulatory Federal income tax expense, and is carried forward to Schedule C1, line 27.

Q. Does the computation of income tax expense included in the revenue requirement comply with Act No. 40 of 2016, which amends the Public Utility Code regarding the treatment of income tax expense for ratemaking purposes?

A. Yes. The computation of income tax expense for ratemaking purposes, presented on Schedule C1-4 (i.e., in the revenue requirement), reflects a tax deduction for each item of expense of investment (i.e., depreciation expense) in the revenue requirement. In addition, there are no items that reduce the income tax expense for ratemaking purposes, or increase the deferred tax liability, other than reflected in the revenue requirement.

Q. Did you compute the Net Utility Operating Income and Return on Rate Base at present rates?

A. Yes. Schedule C1, line 28 and Schedule C5, line 14 show Net Utility Operating Income at Present Rates for the HTY, FTY and FPFTY. Schedule C1, line 31 shows Return on Rate Base for distribution-only at present rates of 5.27% for HTY 2024, 3.48% for FTY 2025 and 1.46% for FPFTY 2026.

RATE BASE FOR THE FTY AND FPFTY

Q. How did you develop the Rate Base?

A. The Rate Base at the end of the HTY, FTY and FPFTY is presented in Schedule C1-5. Schedule C3, page 1, shows the asset values at original cost in PAPUC / FERC account detail at December 31, 2023, actual additions and retirements in HTY 2024, and planned additions for FTY 2025 and FPFTY 2026. Annual depreciation expense is computed as

stated above. Accumulated depreciation at each year-end is computed by adding annual depreciation expense, and subtracting retirements, to the prior year-end balance.

The amounts in Rate Base for Customer Deposits and Materials and Supplies, were taken from the Balance Sheets for the HTY, FTY and FPFTY presented in Schedule C2. The HTY information is from Citizens' financial statements at December 31, 2024. These items were estimated to be the same for the FTY and the FPFTY as for the HTY.

The rate base includes a reduction for Accumulated Deferred Income Taxes ("ADIT"), equal to the difference between Accumulated depreciation based on X) Depreciation used to compute the Federal tax expense borne by ratepayers (i.e., using straight line method discussed above) and Y) Depreciation used to compute Citizens' actual tax Federal tax expense (i.e., based on double declining balance method), times the current Federal income tax rate. The ADIT is computed on Schedule C1-5, lines 27-32 and carried up to line 6.

The rate base includes a reduction for Accrued Pension / OPEB liability, reflecting the excess of amounts charged to expense over amounts paid (Schedule C1-5, lines 42-47, carried up to Schedule C1-5, line 9).

Cash Working Capital was determined by using the widely-accepted formula of 1/8 of non-fuel cash operating costs (Schedule C1-5, lines 15-25, carried up to line 12).

The total Rate Base, Schedule C1-5, line 13, is carried forward to Schedule C1, line 30.

NET UTILITY OPERATING INCOME

Q. What revenue is included in the distribution revenue requirement?

A. The revenue requirement includes:

- Electric operating revenue: Revenue from distribution of electricity, including exchange with other utilities.

- Other Revenue: Other revenue includes Forfeited Discounts (late payment charges), Revenue from rental of electric property and Miscellaneous revenue.

The revenue requirement excludes Unbilled Revenue, because the FPFTY is fully normalized, and GSSR Revenue, because this is a distribution-only rate case.

Q. What is the distribution revenue requirement for the FPFTY?

A. FPFTY forecast revenue at present rates (including Other revenue) is $6,159,000. The FPFTY revenue required to produce Mr. D'Ascendis' and Mr. Kucan's recommended rate of return of 8.49% is $7,953,000. Citizens' is requesting a revenue increase of $1,795,000, to produce total revenue of $7,953,000. See Schedule C1, line 10.

Q. What rate of return on rate base did Mr. D'Ascendis and Mr. Kucan recommend?

A. They recommend a return of 8.49%. The revenue required (including Other income) to produce this return is $7,953,000, and the Company's proposed rates produce this revenue.

ALLOCATED CLASS COST OF SERVICE STUDY

Q. Please briefly describe the purpose of an allocated class cost of service study.

A. The purpose of an allocated class cost of service study ("ACOS") is to assign, on a cost-causation basis, the total distribution revenue requirement of a utility among the rate classes in its Tariff. In performing the ACOS, each of the utility's costs of providing service is analyzed, in order to assign or allocate the costs among the rate classes, so that the utility can establish rates that ensure, subject to assumptions such as delivery volumes and customer counts, that it recovers its costs in full from each class.

Q. What are the guiding principles in performing an ACOS?

A. The essential element in performing an ACOS is the selection of allocators based on causal relationships between customer demands, load profiles and usage characteristics on one hand, and the costs incurred by the Company to meet those requirements on the other hand. The primary goals in selecting allocators are:

1. recognition of **cost causality** as opposed to **value of service**;
2. **stability** of results over time;
3. logical **consistency** and **completeness**; and
4. ease of implementation.

Q. What rate classes are included in Citizens' ACOS?

A. The rate classes included in Citizens' ACOS are Schedule RS- Residential; Schedule GLP1 - General Light and Power Service; Schedule GLP3 - General Light and Power Service; Schedule SH - Space Heating; Schedule MBL - Municipal Boulevard Lighting and Schedule OL – Outdoor Lighting.

Q. Please summarize the approach you followed in preparing Citizens' ACOS.

A. The most critical task in performing an ACOS is establishing relationships between customer demands, load profiles and usage characteristics on one hand, and the costs incurred to meet those requirements on the other hand. This requires an understanding of the utility system design and its relationship to the characteristics of the customers it is designed to serve. Citizens', like most utilities, designs its electric distribution system to meet three primary objectives:

1. To extend distribution services to all customers;

2. To deliver the aggregate peak demand for electricity of all firm delivery customers; and

3. To deliver electricity to customers throughout the year.

The allocation of costs in a class cost of service study must recognize these ***cost-causative*** characteristics of the utility's plant investments and operating expenses. A cost of service study should objectively reflect cost-causation factors and should not be influenced by end-results or other revenue allocation and rate design considerations.

Citizens' ACOS follows the traditional three-step process: 1) *functionalization* of rate base and costs; 2) *classification* of functionalized costs as demand-related, commodity-related or customer-related; and 3) *class allocation* of the functionalized, classified costs among the rate classes.

Q. Are there are changes from the methodology used in Citizens' last rate case, Docket R-2022-3032692?

A. No, the methodology is the same.

Q. What functions are reflected in the ACOS?

A. The Citizens' ACOS includes the following functions:

Primary Distribution - Designed to move power from the transmission system to the Secondary Distribution system; includes substations as well as conductors operating primarily at voltages of over 600V up to and including 12 kV, and related assets.

Secondary Distribution - Designed to move power from the Primary Distribution system to customers' premises; includes services.

Billing - Includes meter as well as assets and activities related to enabling the distribution of electricity to customers, and billing and collecting revenue.

Citizens' does not own any transmission-voltage facilities of over 12 kV.

Q. Please describe the classification step of an ACOS.

A. In the **classification** step, the previously functionalized assets and costs are separated according to the system design or operating characteristics that cause those costs to be incurred in the first instance. Each asset and cost is determined to be incurred to serve **customers**, to deliver the electricity or **commodity** year-round or to meet peak **demand** including coincident and non-coincident peaks ("NCPs").

Customer related costs are the costs incurred to attach a customer to the distribution system, to meter usage and to maintain the customer's account. Customer costs are a function of the number of customers served and continue to be incurred whether or not the particular customer uses any electricity. They include capital costs associated with services and meters, and operating costs such as customer service, field service, billing and accounting expenses.

Commodity related costs are those costs that vary with the quantity of electricity delivered throughput sold to, or transported for, customers. These costs include purchased electricity costs and related costs.

Demand, or **capacity**, related costs are associated with plant that is designed, installed and operated to meet peak usage. Distribution assets are designed to meet the peak loads of the particular customers they serve.

Q. Please describe the class allocation step of an ACOS.

A. In the **class allocation** step, the functionalized, classified costs are allocated among the rate classes, based on causal relationships with the utility's system design and operations, its accounting records and its system and customer usage and load data. Based on the analyses

of cost relationships, each plant and cost item in the rate base and revenue requirement is directly assigned to a rate class, or an allocator is selected to apportion the item.

Q. Please explain the term "direct assignment."

A. The term "direct assignment" means identifying plant investments or costs incurred exclusively to serve a specific customer or group of customers. Direct assignments best reflect the cost-causation of serving individual customers or groups of customers and should be used whenever the data are available.

Q. In a typical ACOS are most costs directly assigned, or are most costs allocated?

A. Most costs must be allocated, because utility operations are characterized by common facilities. In addition, direct assignments require detailed information which may be unavailable or require a great deal of time to prepare. The assets and costs that cannot be directly assigned are distributed among the rate classes using allocation factors.

Q. Please explain how allocators are derived.

A. Two types of allocators are typically used in performing an ACOS: external allocators and internal allocators. *External allocators* are based on special studies derived from the utility's accounting and other records. Examples of external allocators are number of customers and NCPs. Schedule D lists the external allocators used in the ACOS, and Schedules D1 through D6 show the development of the external allocators.

Internal allocators are based on some combination of external allocators, previously directly assigned costs and other internal allocators. For example, the allocator for property insurance costs is based on plant investment amounts assigned to components of the rate base; as a result, it is necessary to compute the rate base before property insurance costs

can be allocated. Both external and internal allocators are used in functionalization, classification and class allocation.

Q. What is the rate base and how is it used in the ACOS?

A. The rate base is the cost, net of accumulated depreciation, of Citizens' investment in plant and other assets used to serve customers. The FPFTY rate base is $17,092,000 (Schedule C1 and Schedule C1-6). Citizens' is requesting an increase of $1,795,000, which will produce a return on rate base of 8.49%, as discussed above. The ACOS allocates the rate base (and return of 8.49%) among rate classes.

Q. What are the major components of Citizens' rate base?

A. The major categories in Citizens' rate base are:

- Distribution plant
- Intangible plant
- General plant
- Depreciation reserve
- Other rate base items

Q. How was distribution plant functionalized, classified and allocated among the rate classes?

A. Distribution plant comprises:

Land and Land Rights and Stations Equipment were functionalized to Primary Distribution, classified as demand and allocated among the rate classes using the NCP-Primary allocator.

Poles, Towers and Fixtures; Overhead Conductors and Devices; Underground Conduit; Underground Conductors & Devices were functionalized between Primary and Secondary based on circuit miles / lines miles (Schedule D1, lines 1-28).

The Primary portion was classified as demand-related and allocated among the rate classes using the NCP- Primary allocator.

The Secondary portion was classified between customer-related and demand-related using a zero-load analysis. The portion of total installation costs that are labor-related (i.e., all costs except material) were classified as customer-related, and the balance as demand-related (Schedule D1, lines 29-34, equal to the averages over the current and four prior rate cases). The zero-load component of the Secondary system represents the cost of extending service to all customers, without regard to peak or average load, and is therefore customer-related. The assets and costs functionally classified to Secondary-customer were allocated among the rate classes based on number of customers served at Secondary voltages. The assets and costs functionally classified to Secondary-demand were allocated using the NCP- Secondary allocator.

Line Transformers were functionalized to Secondary and classified between customer-related and demand-related using a minimum size analysis (Schedule D3). The minimum size was determined to be a 50 kVA transformer serving four customers, or one-fourth of a 50 kVA transformer. The minimum size portion was classified as customer-related and allocated among the rate classes based on number of customers served at Secondary voltages. The balance of costs were classified as demand-related and allocated using the NCP-LTr allocator, which is the NCP-Secondary allocator reduced by the load-carrying capacity of the minimum size transformers (Schedule D2, lines 26-38).

Services connect individual customers to the system, and were functionalized to Secondary, classified as customer-related and allocated based on total replacement cost for each class (Schedule D4). Total replacement cost of Services for a class was computed as X) estimated replacement cost of a typical service for the class times Y) number of customer locations in the class.

Meters were functionalized to Billing, classified as customer-related and allocated based on total replacement cost for each class (Schedule D5). Meter costs include CT (current transformers) and PT (Potential transformers). Total replacement cost of Meters for a class was computed as X) estimated replacement cost of meters for the class times Y) number of customers in the class.

Street Lighting and Signal Systems were functionalized to Secondary Distribution, classified as customer-related and directly assigned to Lighting.

Q. What is the NCP-Primary allocator and how was it developed?

A. The NCP-Primary allocator (or "NCP-Prim") is used in the ACOS to allocate, among the rate classes, the assets and costs that are functionalized to Primary distribution. To compute the NCP-Prim allocator, the NCP was determined for each class, for years 2015 and 2018-2024. In each year, each class' share of the sum of all class NCPs was computed. The NCP-Prim allocator for each class is the average of the class' annual shares.

To compute annual NCP, Citizens' provided hourly data for each class, for 2018-2024, and the NCP's were determined for each year. Information for 2015 is from a prior rate case (Docket R-2016-2531550). For SH and MBL, 2024 shares of NCP were used because 1) SH has had significant changes in number of customers and 2) MBL has had significant changes in kWh due to using energy-efficient LED lights.

NCP-Prim computations are presented on Schedule D2, lines 1-20. In computing the NCP-Prim allocator, metered values were used.

Q. What is the NCP-Secondary allocator and how was it developed?

A. The NCP-Secondary allocator (or "NCP-Sec") is used in the ACOS to allocate, among the rate classes, the assets and costs that are functionalized to Secondary distribution and classified as demand-related, except for Line Transformers (and assets and costs that include Line Transformers).

The NCP-Secondary allocator value for each rate class was computed by removing from the NCP-Prim allocator, customers served at Primary voltages. The computations are shown on Schedule D2, lines 22-24.

Q. What is the NCP-Line-Transformer allocator and how was it developed?

A. The NCP-Line-Transformer allocator (or "NCP-LTr") is used in the ACOS to allocate among the rate classes the cost of Line Transformers that are functionalized to Secondary distribution and classified as demand-related. It represents the demands on the Secondary distribution system in excess of the minimum system and is equal to the NCP-Secondary allocator values, minus the load-carrying capacity of the minimum size transformers (Schedule D2, lines 26-38).

Q. How was General plant functionalized, classified and allocated among rate classes?

A. General plant includes primarily Structures and improvements, Office furniture and equipment, Computers and Communications equipment, as well as other assets. These assets were functionalized, classified and allocated among rate classes based on direct labor content of operating expenses, reflecting the nature of the assets and common cost of service practice.

Q. How was Accumulated Depreciation functionalized, classified and allocated among rate classes?

A. Each component of the Depreciation reserve was functionalized, classified and allocated among rate classes in the same ratio as the related assets.

Q. How were other Rate Base Items functionalized, classified and allocated among rate classes?

A. Other Rate Base Items were functionalized, classified and allocated as follows:

Cash Working Capital represents Citizens' need for cash to keep the business running until revenues are collected to pay costs. This item was functionalized, classified and allocated in proportion to operating expenses.

Materials and Supplies was functionalized, classified and allocated in proportion to operating expenses.

Customer Deposits were directly assigned between Residential and Non-residential, then allocated based on revenues (Schedule D6).

ADIT was functionalized, classified and allocated in proportion to plant in service.

Accrued Pension/OPEB Liability was functionalized, classified and allocated in proportion to labor content of O&M expense accounts.

Q. What are the major categories of Citizens' costs?

A. The major cost categories in Citizens' cost of service are:

- Distribution operating and maintenance expenses
- Customer accounts and service expenses
- Administrative and general expenses
- Depreciation expense

- Tax expense, other than on income
- Income tax expense

Q. In determining how to treat these costs in the ACOS, was any other important category of costs considered?

A. Yes, labor costs affect most of the cost categories because many costs are assigned based on the direct labor content of other costs. For example, Administrative & General Salaries, Account 920, is allocated among rate classes based on the direct labor content of operating expense accounts. To perform these allocations, the direct labor content of each cost account was provided by Citizens', and appropriate allocators were developed.

Q. What costs are included in distribution operating and maintenance costs and how were they functionalized, classified and allocated among the rate classes?

A. Citizens' distribution operating and maintenance costs includes operating and maintenance costs for its distribution system including stations; poles, towers and fixtures; overhead and underground conductors and related equipment; meters; line transformers; lighting; and other assets. Each cost was analyzed to determine which assets it was incurred to operate or maintain, and the cost was functionalized, classified and allocated among rate classes in the same manner as those assets. For example, Miscellaneous distribution expenses, Account 588, relates to the Overhead and Underground assets, and was functionalized, classified and allocated in the same manner as Overheard Conductors and Devices, and Underground Conduits and Conductors.

Q. What costs are included in customer accounts and service expenses and how were they functionalized, classified and allocated among the rate classes?

A. Customer-accounts costs includes primarily meter-reading expenses, customer records and collection expenses and uncollectible-accounts expense. These costs were functionalized to Billing and classified as customer-related.

Meter Reading Expenses were allocated among the rate classes in proportion to Meter costs.

Customer Records and Collection Expenses includes activities for billing, call center, payment processing, recoveries and service initiation / termination, and were allocated based on the number of customers.

Uncollectible Accounts Expense was directly assigned between Residential and Non-residential based on Citizens' historic data, then allocated among the specific rate classes based on revenues (Schedule D6).

Q. How were Administrative and General expenses functionalized, classified and allocated among rate classes?

A. Administrative and General ("A&G") expenses comprises the following:

A&G salaries, Office supplies and expense, and Employee benefits were functionalized, classified and allocated among rate classes based on labor content of the operating and maintenance and customer accounting costs. Most Employee benefits costs are included in the O&M and customer accounting accounts, and not in A&G costs.

Property Insurance, Injuries and Damages and Maintenance of General Property were functionalized, classified and allocated based on plant costs.

Outside Services and Miscellaneous General Expenses were functionalized, classified and allocated based on a 50/50 weighting of labor and plant costs.

Regulatory Commission Expenses were functionalized to Billing, classified as customer-related and allocated among rate classes in proportion to rate base. As discussed above, this account include amortization of rate case expense, and recovery of extraordinary costs associated with the Coronavirus pandemic.

Q. How was depreciation expense functionalized, classified and allocated among rate classes?

A. Depreciation expense was computed for each asset account (Schedule C3); each component was functionalized, classified and allocated among rate classes in proportion to the related assets.

Q. How were taxes other than GRT and income taxes functionalized, classified, and allocated among the rate classes?

A. These taxes are PURTA and PA Use taxes, which were functionalized, classified and allocated among rate classes in proportion to plant, and PUC Assessment which was functionalized, classified and allocated among rate classes in proportion to rate base.

Q. How was GRT functionalized, classified, and allocated among the rate classes?

A. GRT is based on revenue, and GRT at present rates was computed for each function, classification and rate class on that basis. In computing the revenue requirement, the GRT expense for each class was computed based on class revenue requirements.

Q. How was income tax expense functionalized, classified and allocated among rate classes?

A. Income tax expense in the FPFTY was functionalized, classified and allocated in proportion to pretax income. For the FPFTY revenue requirement, Income tax expense for each class equals pretax income, grossed up.

Q. How was revenue at present rates computed for each rate class?

A. Distribution Revenue at Present Rates is shown on Schedule B1. The total was functionalized and classified based on pro forma revenue requirements and was assigned to each rate class based on forecast revenue at present rates for each rate class.

Forfeited Discounts was functionalized to Billing and allocated based on historical experience for write-offs.

Rent for Electric Property represents pole rental revenue and was functionalized, classified and allocated in proportion to Poles, Towers and Fixtures.

Other Electric Revenue was allocated in proportion to Distribution revenue.

Q. How was the revenue requirement for each rate class developed?

A. The revenue requirements for each rate class are computed in the same manner as for the total Company, as shown on Schedule C1. The revenue requirement for each rate class is the sum of allocated operating expenses, depreciation expense, general taxes, return on rate base and income tax expense. Return on rate base was computed by multiplying the class' rate base by the proposed rate of return, 8.49%. Income tax expense for each class was computed by grossing up the required return on rate base for the class at the income tax rate related to the overall revenue requirement. GRT for each class was computed by grossing up the required revenue for the class including income tax. Schedule E-1A, line 179 and Schedule E-1, line

13, show the total rate class revenue requirements based on fully allocated distribution cost of service at the proposed Rate of Return.

Q. Please summarize the results of the ACOS.

A. Schedule E-1, shows Net income at present rates for each rate class (line 7) and Return on rate base at present rates (line 11). It also shows the revenue requirement for each class to produce the proposed system return of 8.49% (line 13) and the increase or decrease this represents over revenue at present rates (line 28).

PROPOSED REVENUE ALLOCATION

Q. What were the considerations in the proposed revenue allocation for each class?

A. The following objectives were established for the proposed revenue allocation:

- To move each class closer to cost of service, computed in the ACOS (Schedule E-1).
- To mitigate extreme rate impacts on rate classes and on customer subgroups.

Q. Have you prepared a schedule that presents the proposed revenue allocation?

A. Yes. Schedule B6-4 presents the proposed revenue allocation and related information. Lines 1-8 present the results of the ACOS, including revenue, net income and return on rate base at present rates. Lines 10-21 present the revenue requirement for each class to provide a return of 8.49%, to produce an increase in revenue of $1,794,000. This information is from Schedule E-1.

Schedule B6-4 shows, for each rate class:

- Proposed revenue target for each class (line 24);
- Proposed increase in dollars (line 36), as a percent of present rate distribution revenue (line 37) and present rate total bill (using the presently effective GSSR rate

of $0.08695 per kWh) (line 38) and distribution increase relative to the average increase of 29.6% (line 40);

- Return on rate base at the proposed revenue allocation (line 32) and relative to the average of 8.49% (line 33) and progress toward unity (line 34) (how much of the gap between x) relative return at present rates and y) relative return at proposed revenue allocation, is closed based on the proposed revenue allocation); and
- Change in subsidy paid (received) (lines 42-45), where the subsidy is the difference between xx) rate of return produced by the rate class and yy) average rate of return, applied to the rate base allocated to the class.

Q. Have you prepared a schedule that presents the proposed rates?

Yes. The Company's proposed rates are presented on Schedule B6-3, lines 12-21, and also on Schedule B7. Schedule B6-3 demonstrates that the proposed rates produce the class revenue targets (compare lines 29 and 30; differences due to rounding).

Q. Why do you believe the proposed revenue allocation presented at Schedule B6-4 is fair and reasonable?

A. The revenue allocation is fair and reasonable because all classes make significant progress toward the system average return (Schedule B6-4, line 34), meeting the goal of moving each class closer to cost of service; and no class receives an increase greater than 75% (Schedule B6-4, line 37), meeting the goal of mitigating extreme impacts. In addition, all classes have reductions in the subsidy paid or received (Schedule B6-4, line 45).

PROPOSED RATES

Q. Please identify exhibits that show FPFTY sales and revenue at proposed rates.

A. Schedule B6 shows the same information as Schedule B, with an additional column showing distribution revenue at "PROPOSED Rates" for FPFTY 2026. The information in this column is from Schedule B6-1, carried forward from Schedule B6-2. Schedule B6-2 summarizes the computations of billing units times proposed rates, on Schedule B6-3.

Q. Did you prepare a schedule that summarizes the present and proposed rates?

A. Yes. Schedule B6-3 presents the proposed rates for each rate class. Schedule B7 presents the present and proposed rates for each rate class in a table.

Q. Did you compare the amounts that typical customers in each rate class would pay under the present and proposed rates?

A. Yes. Schedule B8 compares the amounts customers in each rate class, with a range of usage levels, would pay in the FPFTY, at present rates and proposed rates, on a total bill basis (including the present GSSR rate). Schedule B8-1 compares the amounts distribution-only (excluding GSSR). Schedule B8-2 compares total bills, reflecting the proposed GSSR rate that Citizens' filed in mid-April with a proposed effective date of June 1, 2025 for both 'the 'present rate' and 'proposed rate' calculations.

Q. Did you prepare a schedule showing the number of customers whose bills would increase under the proposed rates?

A. Yes. Schedule B5 presents that information.

Q. What were the goals for rate design?

A. The goals of rate design for each class were to produce the target revenue, to align the rates more closely with costs, to stabilize revenue for the utility and costs for customers and to mitigate extreme impacts on most customers.

Q. How did you compute the proposed rates for Residential?

A. For Residential, the proposed monthly charge is $16.50, less than the customer-related costs typically included based on the ACOS ($17.94, Schedule E1-C, line 27). The balance of the class revenue target is proposed to be recovered in the volumetric kWh charge.

Q. How did you compute the proposed rates for Space Heating?

A. For Space Heating, the proposed monthly charge is $24.00, less than the customer-related costs typically included based on the ACOS ($29.35, Schedule E1-C, line 27). The balance of the class revenue target is proposed to be recovered in the volumetric kWh charge.

Q. How did you compute the proposed rates for GLP-1?

A. For GLP-1, the proposed monthly charge is $21.00, less than the customer-related costs typically included based on the ACOS ($21.47, Schedule E1-C, line 27). The demand charge and the volumetric kWh-based rates were each increased by the same proportion (29.1%) to produce the balance of the class revenue target.

Q. How did you compute the proposed rates for GLP-3?

A. For GLP-3, the proposed monthly charge is $100.00, less than the customer-related costs typically included based on the ACOS ($128.65, Schedule E1-C, line 27). Each other rate component (demand charge, reservation charge, both blocks of the volumetric rate and the voltage discount) was increased by the same proportion (28.7%) to produce the balance of the class revenue target.

Q. How did you compute the proposed rates for MBL?

A. The two components of MBL rates, Meter and Post, were each increased by the same percentage, 75%, to produce the class revenue target.

Q. How did you compute the proposed rates for OL (Public Lighting)?

A. The rates for each lamp OL were changed by the same percentage, 28.8%, to produce the class revenue target.

Q. Do the proposed rates produce the required revenue?

A. Yes. Schedule B6-3, line 29, shows the proposed rates produce FPFTY total distribution revenue of $7,849,000 (excluding Other revenue), equal to Schedule C1, line 6. This revenue is an increase of $1,795,000, and produces a return of 8.49%,

Q. Does this conclude your Direct Testimony?

A. Yes.

BEFORE

THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	**:**	
	:	
v.	**:**	**Docket No. R-2025-_____**
	:	
Citizens' Electric Company of Lewisburg, PA	**:**	

EXHIBITS

OF

HOWARD S. GORMAN

ON BEHALF OF

CITIZENS' ELECTRIC COMPANY OF LEWISBURG, PA

APRIL 29, 2022

RESUME OF
HOWARD S. GORMAN

SUMMARY

Mr. Gorman has more than 35 years of experience in the energy industry, including 25 years in rate and regulatory proceedings. His areas of expertise include embedded class cost of service studies, marginal cost studies, revenue allocation, rate design and revenue requirements, for both electric and gas utilities. He has testified as an expert witness before the Massachusetts Department of Public Utilities, New Hampshire Public Utilities Commission, New Jersey Board of Public Utilities, New York State Public Service Commission, Ontario Energy Board, Pennsylvania Public Utility Commission and Rhode Island Public Utilities Commission. Mr. Gorman also has experience in financial modeling, financial analysis and forecasting and treasury and financial management.

PROFESSIONAL EMPLOYMENT

2010 - Present	HSG Group, Inc. • *President*
1997 - 2010	Black & Veatch Corporation (R.J. Rudden Associates, Inc. before 2005) • *Principal Consultant*
1995 - 1997	Independent Consultant
1987 – 1995	Trigen Energy Corporation • 1987-1993- *Corporate Controller; Trigen was formed in 1987* • 1993-1995- *Treasurer; Trigen had IPO with NYSE listing in 1994*
1982 - 1987	Coleco Industries, Inc. • *Director, Treasury*
1976 - 1979	Touche Ross & Co. • *Staff Accountant*

PROFESSIONAL EXPERIENCE

Utility Accounting and Costing

Mr. Gorman has performed numerous class cost of service studies, and has developed and supported revenue requirements, revenue allocation, rate designs and marginal cost studies, in rate cases before regulatory commissions in several jurisdictions, for electric and gas utilities. These assignments included developing test year data and rate year forecasts, establishing cost causality, selecting and developing allocators and analyzing customer impacts and policy considerations

Energy Project Analysis and Financing

Mr. Gorman has negotiated and completed transactions including construction and term loans, tax-exempt bonds, taxable bonds, subordinated debt and asset-backed (receivables and inventory) revolving credit facilities. He has worked successfully with lenders and borrowers to source and structure transactions, and was instrumental in negotiating loan documents and in designing power sale and supply procurement contracts to be financed. Mr. Gorman has performed financial analyses of energy-related assets, including electric and gas distribution companies, power plants and transmission operators. These analyses included development of cash flows and financial statements based on both regulatory and accounting presentations, and included review of assumptions, analysis of data, modeling and forecasting, sensitivity testing and stress testing.

Accounting and Financial Management

As controller of Trigen Energy Corporation, Mr. Gorman built the finance and accounting function; developed reports, procedures and management tools; and managed subsidiary controllers across North America, including an IPO with NYSE listing. He managed the corporate insurance portfolios and the benefit plans for Trigen Energy Corporation and for Coleco Industries, and has managed interest rate and currency forward contracts for the purpose of managing risk.

Publications And Presentations

"What Wall Street Needs From FERC," published in R. J. Rudden Financial, LLC's *Energy Capital Markets Report*, September 2002

"A Balanced Look at Balance Sheets," published in R.J. Rudden Financial, LLC's *Energy Capital Markets Report,* June 2002

"Assessment of Retail Choice Programs," presented at the American Gas Association Rate and Strategic Issues Committee Conference, March 2002

"The Remarkable Story on Enron," published in Scudder's *Annual End of Year Issue*, 2001

Education

New York University, B.S., Accounting, 1976
Harvard Business School, MBA, 1981

Relevant Projects			
Jurisdiction	**Docket**	**Client**	**Subject Matter**
Federal Energy Regulatory Commission 2024	ER24-2795-000, ER24-2796-000	Massachusetts / Nantucket Electric	Electric revenue requirement and rate design for Energy Storage Systems
New York 2024	24-E-0322	Niagara Mohawk (Gas)	Gas class cost of service; revenue allocation; rate design; marginal cost
New York 2024	24-G-0323	Niagara Mohawk (Electric)	Electric class cost of service; revenue allocation; rate design; marginal cost
Pennsylvania 2024	R-2024-3046523	Duquesne Light	Electric class cost of service; revenue allocation; rate design; special study
Massachusetts 2023	DPU 23-150	Massachusetts / Nantucket Electric	Electric class cost of service; revenue allocation; rate design
New Jersey 2024	GR24020158	Elizabethtown Gas.	Gas class cost of service; revenue allocation; rate design
Massachusetts 2023	DPU 23-150	Massachusetts / Nantucket Electric	Electric class cost of service; revenue allocation; rate design
New York 2023	23-G-0227	Valley Energy, Inc.	Gas revenue requirements, rate design
New York 2023	23-G-0225 /02260	Brooklyn Union Gas / KeySpan Gas East	Gas class cost of service; revenue allocation; rate design; marginal cost
Pennsylvania 2022	R-2022-3032369	Citizens' Electric of Lewisburg, PA	Electric revenue requirements, class cost of service, revenue allocation, rate design
Pennsylvania 2022	R-2022-3032300	Valley Energy, Inc.	Gas revenue requirements, rate design
Pennsylvania 2021	R-2021-3024060	Vicinity Energy Philadelphia	Steam system revenue requirements; sales forecast (formerly Veolia)
Pennsylvania 2021	R-2021-3024750	Duquesne Light	Electric class cost of service; revenue allocation; rate design
New York 2020	20-G-0381	Niagara Mohawk (Gas)	Gas class cost of service; revenue allocation; rate design; marginal cost
New York 2020	20-E-0380	Niagara Mohawk (Electric)	Electric class cost of service; revenue allocation; rate design; marginal cost
Pennsylvania 2019	R-2019-3008212	Citizens' Electric of Lewisburg, PA	Electric revenue requirements, class cost of service, revenue allocation, rate design
Pennsylvania 2019	R-2019-3008208	Wellsboro Electric Company	Electric revenue requirements, class cost of service, revenue allocation, rate design
Pennsylvania 2019	R-2019-3008209	Valley Energy, Inc.	Gas revenue requirements, rate design
New York 2019	19-G-0309 /0310	Brooklyn Union Gas / KeySpan Gas East	Gas class cost of service; revenue allocation; rate design; marginal cost
Massachusetts 2018	DPU 18-150	Massachusetts / Nantucket Electric	Electric class cost of service; revenue allocation; rate design; marginal cost Monthly Minimum Reliability Contribution
Pennsylvania 2018	R-2018-30000124	Duquesne Light	Electric class cost of service; revenue allocation; rate design

Relevant Projects			
Rhode Island 2017	RIPUC 4770	Narragansett Electric	Electric class cost of service; revenue allocation; rate design
Pennsylvania 2017	R-2017-2593142	Veolia Energy Philadelphia	Steam system revenue requirements; sales forecast
New York 2017	17-G-0239	Niagara Mohawk (Gas)	Gas class cost of service; revenue allocation; rate design; marginal cost
New York 2017	17-E-0238	Niagara Mohawk (Electric)	Electric class cost of service; revenue allocation; rate design; marginal cost
Pennsylvania 2016	R-2016-2531550	Citizens' Electric of Lewisburg, PA	Electric revenue requirements, class cost of service, revenue allocation, rate design
Pennsylvania 2016	R-2016-2531551	Wellsboro Electric Company	Electric revenue requirements, class cost of service, revenue allocation, rate design
New Hampshire 2016	DE 16-383	Granite State Electric	Electric revenue requirement
New York 2016	16-G-0058 /0059	Brooklyn Union Gas / KeySpan Gas East	Gas class cost of service; revenue allocation; rate design; marginal cost
Massachusetts 2015	DPU 15-155	Massachusetts / Nantucket Electric	Marginal cost
New York 2015	15-E-0184	Jamestown Board of Public Utilities	Electric revenue requirements
New Hampshire 2015	DE14-180	Energy North Natural Gas	Gas revenue requirements
New York 2014	14-E-0035	Village of Freeport	Electric revenue requirements; sales forecast; rate design
Pennsylvania 2014	R-2013-2386293	Veolia Energy Philadelphia	Steam system revenue requirements and sales forecast
Pennsylvania 2014	R-2013-2372129	Duquesne Light	Electric class cost of service; revenue allocation; rate design
New Hampshire 2013	DE13-063	Granite State Electric	Electric class cost of service (marginal cost); revenue allocation; rate design
Ontario 2013, 2012, 2010, 2009, 2008, 2006, 2005	EB-2005-0378 et al	Hydro One Networks Inc.	Electric Transmission and Distribution cost allocation; OH capitalization rates
Ontario 2006-2013	EB-2007-0905 et al	Ontario Power Generation	Electric cost allocation methodology (2013, 2010, 2006)
New York 2012	12-E-0201	Niagara Mohawk (Electric)	Electric class cost of service; revenue allocation
Rhode Island 2012	RIPUC 4323	Narragansett Electric	Electric class cost of service
New York 2011	11-E-0590	Village of Rockville Centre	Electric revenue requirements; rate design; sales forecast
New York 2011	11-G-0142	Chautauqua Utilities, Inc.	Gas revenue requirements, rate design
Pennsylvania 2010	R-2010-2179522	Duquesne Light	Electric class cost of service; revenue allocation; rate design

Relevant Projects			
Pennsylvania 2010	R-2010-2172662	Wellsboro Electric	Electric revenue requirements, class cost of service, revenue allocation, rate design
Pennsylvania 2010	R-2010-2172665	Citizens' Electric of Lewisburg, PA	Electric revenue requirements, class cost of service, revenue allocation, rate design
Pennsylvania 2010	R-2010-2174470	Valley Energy, Inc.	Gas revenue requirements, rate design
Pennsylvania 2010	R-2010-2161592	PECO Energy (Gas)	Gas class cost of service; revenue allocation; rate design
Pennsylvania 2010	R-2010-2161575	PECO Energy (Electric)	Electric class cost of service; revenue allocation; rate design
New York 2010	10-E-0050	Niagara Mohawk (Electric)	Electric class cost of service
New York 2009	09-E-0862	Jamestown Board of Public Utilities	Electric revenue requirements
Pennsylvania 2009, 2006, 2002, 2001	R-2139884 R-00061931 M-00021612 R- 00017034 R- 00006042	Philadelphia Gas Works	Gas class cost of service; revenue allocation; rate design; unbundling; fixed costs recovery
Rhode Island 2009	RIPUC 4065	Narragansett Electric	Electric class cost of service; revenue allocation; rate design
Massachusetts 2009	DPU 09-39	Massachusetts / Nantucket Electric	Electric revenue requirements; class cost of service; revenue allocation; rate design
Pennsylvania 2008	R-2008-2028394	PECO Energy (Gas)	Gas class cost of service; revenue allocation; rate design
Pennsylvania 2007	R-00072350	Wellsboro Electric	Electric revenue requirements; rate design
Pennsylvania 2007	R-00072348	Citizens' Electric of Lewisburg, PA	Electric revenue requirements; rate design
Pennsylvania 2007	R-00072349	Valley Energy, Inc.	Gas revenue requirements; rate design
New York 2006	06-E-0911	Village of Freeport	Electric revenue requirements; rate design
Pennsylvania 2006	R-00061346	Duquesne Light	Electric class cost of service; revenue allocation; rate design
New York 2003	03-E-1568	Village of Rockville Centre	Electric revenue requirements; rate design; sales forecast
New Jersey 2002	ER02080506, ER02050303 et al	AmeriSteel (intervenor)	Electric cost allocation and rate design; industrial rates

BEFORE

THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	**:**	
	:	
v.	**:**	**Docket No. R-2025-3054394**
	:	
Citizens' Electric Company of Lewisburg, PA	**:**	

REBUTTAL TESTIMONY

AND EXHIBIT

OF

HOWARD S. GORMAN

ON BEHALF OF

CITIZENS' ELECTRIC COMPANY OF LEWISBURG, PA

AUGUST 13, 2025

BEFORE

THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	**Docket No. R-2025-3054394**
	:	
Citizens' Electric Company of Lewisburg, PA	:	

REBUTTAL TESTIMONY OF HOWARD S. GORMAN
ON BEHALF OF CITIZENS' ELECTRIC COMPANY OF LEWISBURG, PA

Q. Please state your name, occupation and business address.

A. My name is Howard Gorman. I am the President of HSG Group, Inc., a consulting firm specializing in utility rate and regulatory matters, located in Great Neck, NY.

Q. Are you the same Howard Gorman that provided Direct Testimony on behalf of Citizens' Electric Company of Lewisburg, PA ("Citizens'" or "Company")?

A. Yes. Terms defined in my Direct Testimony have the same meaning in this rebuttal testimony.

Q. What is the purpose of your testimony today?

A. The purposes of my testimony are to update the Company's filing and to rebut portions of the testimony of the following witnesses:

- Bureau of Investigation and Enforcement ("I&E") Witness Walker (I&E St. No. 1), regarding Pennsylvania Corporate Income Tax rate, Rate Case expense, Unamortized Rate Case expense and Cash Working Capital.
- I&E Witness Cline (I&E St. No. 3), regarding Materials and Supplies and Customer Deposits amounts in Rate Base, Scale Back and Customer charges.
- Office of Consumer Advocate ("OCA") Witness Myer (OCA St. No. 1), regarding Revenue at present rates and Uncollectible accounts expense.

- OCA Witness Deupree (OCA St. No. 3), regarding the Company's Allocated Class Cost of Service Study ("ACOS"), Revenue allocation and Rate design.
- Office of Small Business Advocate ("OSBA") Witness Farr (OSBA St. No. 1), regarding Pennsylvania Corporate Income Tax rate.
- Kelly Road Solar, LLC, Lancaster Avenue Solar, LLC and Twilight Renewables, LLC ("Solar Projects") witnesses Nolt and Lucas regarding proposed tariff changes.

Q. Are you sponsoring any exhibits today?

A. Yes, I am sponsoring Exhibit___(HSG-1R), which includes an index on Schedule A (R). The Company is supporting an increase of $1,641,472 compared to $1,794,525 in its original filing, reflecting the changes shown in Table HSG-1:

Line	Table HSG-1	Revenue Increase
1	Original Filing	1,794,525
2	Update PA Tax rates	(42,586)
3	Remove GCR Costs from Contra Account 921.9 (2023, 2025, 2026)	(111,048)
4	Remove POLR/PJM-from Rate Base	(8,935)
5	Materials & Supplies Customer Deposits Using most recent 13-month	9,516
6		
7		1,641,472

These changes in the revenue requirement are summarized below:

Items Discussed in This Testimony

- PA Corporate Income tax rate - Change to 7.49% in 2026.
- Rate Case Expense - Remove $8,289 generation-related costs which were included in error.
- Materials and Supplies and Customer Deposits - Include most recent 13-month average balances in rate base.
- Cash Working Capital - Adjust the allowance in Rate Base to equal 1/8 times applicable expenses.
- Revenue Allocation and Rate Design - Revenue Allocation and Rate Design are updated for the revenue requirement on Exhibit___(HSG-1R), Schedule C1 (R).

Items Discussed In Rebuttal Testimony of Other Company Witnesses

- Remove GCR Costs from Contra Account 921.9 - Response to I&E-RE-19-D
- Computation of Billing Demand - The Company is proposing to change the way it calculates Billing Demand that will apply to certain customers as discussed in the testimony of Mr. Johnson (Citizens' St. No. 5R). This change is reflected on Exhibit___(HSG-1R), Schedule B6-3 (R).

Q. Have you updated the ACOS, revenue allocation and rates that Citizens' is proposing to recover its revenue requirement?

A. Yes. The results of the ACOS, and the class revenue required to produce a return of 8.49%, are on Schedule B6-4 (R), lines 1-20. There were no changes in methodology in preparing this ACOS from the original filed ACOS.

The proposed revenue allocation, presented on Schedule B6-4 (R), lines 22-45, including metrics, was updated, and the increase for Rate MBL was adjusted to 1.50X the system average to address a concern by the OCA.

The proposed rates, which produce the revenue target for each class as well as the overall revenue target, are developed on Schedule B6-3 (R), with bill impacts on Schedules B8 (R) and 8-1 (R).

Q. Have you made any changes to the ACOS or the billing units in the rate analysis?

A. Yes, the Company evaluated whether the ACOS and/or rate design should be updated due to the proposal to add the nameplate capacity for a customer generator into the Billing Demand definition.

The Company believes that the change in the Billing Demand definition to add the nameplate of the customer generators does not change the calculation of Non-Coincident

Peaks ("NCP") for these classes because the impact is too uncertain at this time. Therefore, I have not adjusted the allocator values in the ACOS, the ACOS results or the revenue allocation. In future Commission proceedings, once the Company incorporates the change to the Billing Demand definition, there may be impacts to the ACOS, which can be evaluated based on the actual class data.

Regarding rate design, however, the revised definition would impact the billing units for GLP-1 and GLP-3. In computing the proposed rates in Exhibit___(HSG-1R), Schedule B6-3 (R), lines 35-44, the Billing Demand units were computed using the Company's proposed method. As a result, Billing Demand units for GLP-1 increased from 163,587 kW to 203,580 kW; and Billing Demand units for GLP-3 increased from 131,543 kW to 133,103 kW. This affected the computation of the kW-based rates and other rates for these classes. Table HSG-2 below compares the distribution rates for GLP-1 and GLP-3 using the Company's revenue allocation, depending on whether the Company's Billing Demand proposal is accepted, or the existing definition is used.

	Table HSG-2	**GLP-1**	**GLP-1**	**GLP-3**	**GLP-3**
		Existing Billing Demand	Proposed Billing Demand	Existing Billing Demand	Proposed Billing Demand
1	Customer Charge per Month	$21.00	$21.00	$100.00	$100.00
2	Energy Charge per kWh- Block 1	$0.01143	$0.00976	$0.01198	$0.01185
3	Energy Charge per kWh- Block 2			$0.00130	$0.00129
4					
5	Demand per kW	$4.44	$3.79	$6.78	$6.71
6					
7	Reservation Charge per kW			$3.17	$3.13
8	Voltage Discount			($0.29595)	($0.29278)
9					
10	Customer Bills	13,644	13,644	504	504
11	kWh	27,208,762	27,208,762	46,600,138	46,600,138
12	Demand Units	163,587	203,588	131,543	133,103
13					
14	Total Distribution Revenue	$1,323,845	$1,323,678	$1,134,595	$1,135,125

I&E Witness Walker

PA Corporate Income Tax Rate

Q. What does Mr. Walker propose regarding the PA Corporate Income Tax rate?

A. Mr. Walker notes that pursuant to Pennsylvania House Bill 1342 and Act 53 of 2022, the PA Corporate Income Tax rate is 8.49% in 2024, 7.99% in 2025 and 7.49% in 2026, with annual reductions of 0.5% until it reaches 4.99% in 2031 (I&E St. No. 1, p 25). Citizens' original filing inadvertently used 9.99% for 2026. Citizens' agrees that the appropriate rate for 2026 is 7.49%. The correct rates as proposed by Mr. Walker are reflected in the Company's Rebuttal filing, Exhibit___(HSG-1R).

Rate Case Expense

Q. What does Mr. Walker propose regarding Rate Case Expense?

A. Mr. Walker proposes removing $8,298 for PJM/POLR from Rate Case expense because this is a generation-related item, and not a distribution-related item (I&E St. No. 1, p. 9). The Company accepts this adjustment and has removed the item from Rate Case expense (Exhibit___(HSG-1R), Schedule C1-3 (R)).

Unamortized Rate Case Expense

Q. What does Mr. Walker propose regarding Unamortized Rate Case Expense?

A. Mr. Walker proposes removing Unamortized Rate Case expense from rate base, on the grounds that Rate Case expense is a normal operating expense for a utility, and the utility should not earn a return on a normal operating expense (I&E St. No. 1, p. 12).

Q. Do you agree?

A. No. The utility has working capital tied up in unrecovered Rate Case expense and is entitled to a return on that working capital. The Company pays the rate case expense on a

real-time basis during the proceeding, then collects the projected amount included in the Rate Case expense claim over the normalization period without carrying charges. As such, allowing the return on the balance is necessary to compensate Citizens' for the delay between paying the expense and receiving the compensation in post-proceeding distribution revenues.

This treatment is analogous to Materials and Supplies, where the Company has laid out or committed working capital and the item has not flowed through expense yet. The cost of unused Materials and Supplies is routinely included in rate base. For the same reason, the unrecovered portion of Rate Case expense should be included as well, and this adjustment should be rejected.

Cash Working Capital

Q. What does Mr. Walker propose regarding Cash Working Capital?

A. Mr. Walker proposes that the Cash Working Capital ("CWC") allowance be computed based on the Commission's determination of expenses in this case (I&E St. No. 1, p. 24). He accepts the Company's use of the 1/8 convention in computing CWC. The Company adjusts its CWC claim in Rebuttal Exhibit__(HSG-1R) using the 1/8 convention and will use this approach for the final revenue requirement. The Company accepts this proposal.

I&E Witness Cline

Materials and Supplies and Customer Deposits

Q. What does Mr. Cline propose regarding Materials and Supplies and Customer Deposits?

A. Mr. Cline proposes to include these two items in Rate Base based on their 13-month averages for the most recent periods available at the time of determination (I&E St. No. 3,

p. 7). The Company accepts this proposal and has reflected it in its Rebuttal filing, Exhibit___(HSG-1R), Schedule C1-5 (R).

Scale Back and Customer Charges

Q. What does Mr. Cline propose regarding Scale Back and Customer Charges?

A. Mr. Cline accepts the customer charges proposed by the Company based on the revenue requirement in its original filing. He proposes that the final rates be based on "the cost of service study ultimately approved by the Commission" (I&E St. No. 3, pp. 8-9). The Company will submit an ACOS based on the revenue requirement approved by the Commission. If the Commission accepts the Company's ACOS but reduces its requested revenue requirement, then the Company proposes to use a proportionate scale back to allocate the increase. Citizens' does not agree, however, that the proposed customer charges should be reduced (unless an updated customer cost analysis indicates otherwise). The proposed customer charges are consistent with the Commission's policy and should be approved as submitted. I will address in more detail below why appropriate rate design should include customer charges at levels that promote revenue stability for the utility and balance other factors.

OCA Witness Meyer

Revenue

Q. What adjustments to Revenue does Mr. Meyer propose?

A. The Company's sales and revenue forecast was based on annual average kWh per customer, by rate class, over the most recent 5 years. Mr. Meyer proposes using the most recent 10 years, which he supports by showing that the 10-year average is close to the 15-year average. (OCA St. No. 1, pp. 6-11).

Q. Does Mr. Meyer's analysis support his proposed adjustment?

A. No, I believe his analysis supports the Company's position. As shown in Table HSG-3 below, the major rate classes have each shown marked declines in annual kWh usage per customer in recent periods. In fact, the 2023 and 2024 actual numbers are well below the 5-year averages that were used in the Company's forecast. Mr. Meyer's adjustment would exacerbate under-collection of revenues, would short-change the Company in the short run, and would accelerate the need for the next rate case. This adjustment should be rejected by the Commission.

	Table HSG-3	Residential	GLP-1	GLP-3
	Average Annual kWh Per Customer			
1	15-year Average	14,644	26,284	1,290,608
2	10-year Average	14,617	25,907	1,301,308
3	5-year Average (bel	14,488	23,930	1,144,553
4	Change 15-year to 1	(0.18%)	(1.43%)	0.83%
5	Change 10-year to 5	(0.89%)	(7.63%)	(12.05%)
6	Change 5-year to 20	(5.41%)	(5.70%)	(4.85%)
7	Annual 2020	14,723	24,544	1,175,513
8	Annual 2021	14,911	25,044	1,263,563
9	Annual 2022	15,193	24,951	1,146,006
10	Annual 2023	13,906	22,546	1,048,651
11	Annual 2024	13,704	22,566	1,089,034

Uncollectibles Expense

Q. What adjustments to Uncollectibles expense does Mr. Meyer propose?

A. Mr. Meyer proposes to compute Uncollectibles expense using the 5-year average of the ratio of write-offs to revenue. (OCA St. No. 1, pp. 12-13).

Q. Do you agree?

A. No. Mr. Meyer's Table GRM-5 shows a rising trend in this ratio, from a range of 0.120%-0.138% in 2020-2022, to a range of 0.153%-0.157% in 2023-2024. The Company's

Uncollectibles expense ratio of 0.167% is a reasonable continuation of this trend. Mr. Meyer's proposed adjustment should be rejected.

OCA Witness Deupree

ACOS

Q. Please summarize Mr. Deupree's views regarding the Company's ACOS.

A. Mr. Deupree appears to accept the Company's ACOS, *except for* the classification of Secondary portions of distribution plant (Accounts 364, 365, 366) and Line Transformers (Account 368). He claims these items have no customer component and are 100% demand-related. He makes the following arguments in support of his claims:

- Theoretical Nature of Zero-Load System- Mr. Deupree notes that the Company's separation of costs into demand-related and customer-related is based on "hypotheticals that do not exist in the real world, including the assumption that somehow there is an electric distribution system out there in the world that could or would be plausibly built to serve customers but not load" (OCA St. 3, p. 17).

  This is an often-used but misleading argument. I acknowledge that the Zero-Load System, and the Minimum Size System, are theoretical constructs, but this is not a valid reason to reject them. They are useful tools to separate costs between demand-related and customer-related, regardless of the fact that no such systems would be built.

  As an aside, Mr. Deupree's argument regarding Line Transformers is incorrect and just falls apart. However, it would be possible to install transformers with ratings of 12.5 kVA (the minimum size is deemed to be 50 kVA X 1/4) for customers where this is sufficient to meet demand, and to install larger capacity transformers only where needed.

- Load Carrying Capacity- Mr. Deupree cites the NARUC Manual's caution that a minimum system would have a certain load-carrying capacity (OCA St. No. 3, p. 18).

  For items other than Line Transformers, the Zero-Load System presented in my ACOS excludes the cost of materials and would have no load-carrying capacity.

  For Line Transformers, the demand component does reflect the capacity of the minimum system (Exhibit___(HSG-1R), Schedule D2 (R), lines 26-30, with the capacity of the minimum system shown on line 29).

- Bonbright - Mr. Deupree cites Professor Bonbright's claim that including the minimum-sized distribution system in customer-related costs is "clearly indefensible" (Bonbright, p. 492, cited at OCA St. No. 3, p. 20).

  Yet, he ignores Bonbright's claim that "its exclusion from the demand-related costs stands on much firmer ground" (Bonbright, p. 492) and goes ahead and classifies all costs including any minimum size component as demand-related. One cannot simultaneously criticize and rely on the same source.

- Relation to Number of Customers - Mr. Deupree analyzes the relationship between the number of customers the Company added (or lost) 2008 through 2024, and net dollar additions to distribution plant. Unsurprisingly, he found no statistical correlation (OCA St. No. 3, pp. 20-21).

  I applaud Mr. Deupree's efforts, but I disagree with his conclusion that because he could not demonstrate statistical correlation, there is no relationship between the number of customers added and distribution system costs. On the face of it, this conclusion does not make sense. Even in years with decreases in the number of customers, the utility must invest in the distribution system. The reasons that Mr. Deupree does not

demonstrate correlation include: the amount of net investment is affected by asset retirements; net dollar additions to distribution plant vary due to factors other than new customers, such as repairs, maintenance and upgrades; the timing of customer additions has not been matched to the timing of investments; and critically, the dollar value of investments may be affected by demand capacity added, which the analysis ignores.

Mr. Deupree's conclusion that because he could not demonstrate statistical correlation, there is therefore no relationship between the number of customers added and distribution system costs, is wrong.

Q. Please summarize the discussion regarding Mr. Deupree's objections to your ACOS.

A. First, the endpoints of the distribution system connect to customers, usually through a transformer; it is a tautology that the investment in distribution system, especially the Secondary system, is directly related to the number of customers. Regarding Transformers, the Company uses the rule of thumb that one 50kVA transformer serves four residential customers (Schedule D3), establishing a direct relationship between this particular component and the number of customers.

Second, each of the several arguments that Mr. Deupree raises are flawed, as discussed above.

Q. Do other intervenors comment on the Company's ACOS?

A. Yes. OSBA Witness Farr concludes that "the cost of service study aligns with the principles of cost causation and that Citizens' proposed revenue allocation falls within the range of reasonableness" (OSBA St. No. 1, p. 3). I&E Witness Cline does not comment on the ACOS but relies on the Company's ACOS to review customer charges (I&E. St. No. 3, p. 8).

Q. Has the Commission provided guidance regarding minimum system studies in allocated cost studies?

A. Yes, many times. The Commission has repeatedly endorsed minimum system studies, including in Citizens' 2019 rate case, in Wellsboro Electric Company's 2019 rate case at Docket No. R-2019-3008208, in UGI Utilities, Inc.—Electric Division's ("UGI") 2018 rate case at Docket No. R-2017-2640058, and in PPL Electric Utilities Corporation's 2019 and 2012 rate cases. The Commission found that Citizens' analysis in the 2019 rate case, which I personally performed, was reasonable and appropriate for the classification and allocation of distribution system costs.

Q. What do you recommend regarding the Company's ACOS?

A. The Commission must reject Mr. Deupree's criticism of the Company's ACOS for the reasons stated above. The Commission should accept the Company's ACOS, Exhibit___(HSG-1R), Schedule E (R). This ACOS is based on the Company's revenue requirement submitted in Rebuttal, and uses the same methodology as the Company's originally filed ACOS Exhibit___(HSG-1), Schedule E.

Revenue Allocation

Q. What does Mr. Deupree recommend regarding revenue allocation?

A. Mr. Deupree prepared his own ACOS, in which he failed to recognize any customer component of the Secondary distribution system. This is a fatal flaw. He relies on his ACOS for revenue allocation. Because Mr. Deupree's ACOS is fatally flawed, the Commission should reject it and should also reject his recommendations as to revenue allocation, as they rely on the flawed ACOS.

Mr. Deupree also recommends that the increase in the Municipal Boulevard Lighting ("MBL") class be limited to 1.25X the system average increase; the Company is willing to accommodate this request and has reduced the relative increase proposed for this class.

Rate Design

Q. What does Mr. Deupree recommend regarding rate design?

A. Mr. Deupree recommends that the Commission reject the Company's proposed increases to customer charges. He cites several reasons, which I address below.

- Computation of customer-related costs - Mr. Deupree claims the Company's ACOS inaccurately reflects customer-related costs and, presumably, should not be relied on to develop the fixed monthly charge. However, the Company's analysis of customer-related costs for inclusion in the fixed monthly charge (Exhibit__(HSG-1R), Schedule E-1C(R) excludes the Secondary portion of the distribution system, which is the portion of the ACOS that Mr. Deupree contested. The analysis does include Transformers, however, the impact of Transformer-related costs is minor in comparison to total costs. Mr. Deupree has not identified a significant flaw in my computation of the customer-related costs.
- Comparison to other regional utilities - Mr. Deupree claims the Company's present and proposed fixed monthly charges for Residential and Space Heating ("SH") customers are higher than the charges of neighboring regional utilities. This is not relevant to our discussion; however, the Company disagrees with the peer group chosen by Mr. Deupree. As Mr. Johnson explains, the Company's proposals are comparable with Citizens' actual neighboring utility, PPL Electric Utilities Corporation.

- Effect on energy conservation and low-usage customers - Mr. Deupree claims that higher customer charges are contrary to the goal of energy conservation. However, the goal of energy conservation should not be considered in a vacuum; rate design must balance this with concerns such as revenue stability for the utility and efficient price signals, as well as affordability. In fact, Commission policy permits only certain costs to be recovered in the customer charge, and these do not include all fixed costs the utility incurs. As proposed, the customer charge recovers only 23% of monthly distribution charges for a typical residential customer using 1,250 kWh per month. The generation rate is also charged on a kWh basis, which provides more incentive for the customer to pursue energy conservation. Inefficient pricing and under-recovery of costs leads to more frequent rate cases and also to cross-subsidies within rate classes, as costs are shifted to higher-usage customers.

Q. Does the Company's proposed customer charge reflect the cost of service?

A. Yes, the Company's proposed customer charge reflects its analysis of customer-related costs for inclusion in the fixed monthly charge, based on its ACOS (Exhibit___(HSG-1R), Schedule E-1C(R)).

Q. Has the Commission provided guidance on proposed customer charges?

A. Yes, in the UGI 2018 Order in Docket No. R-2017-2640058, p. 173, the Commission said, "Thus, we find that UGI's proposal is consistent with *Lloyd,* which held that rate structures should be adjusted to reflect the cost of service to each rate class and to eliminate cross-subsidization."

Q. What do you recommend?

A. The Company's proposed customer charges are supported by its ACOS. And consistent with Commission policy, I recommend that the Commission approve the Company's proposed customer charges.

OSBA Witness Farr

PA Corporate Income Tax Rate

Q. What does Mr. Farr propose regarding PA Corporate Income Tax Rate?

A. Mr. Farr makes the same proposal as Mr. Walker regarding the PA Corporate Income Tax rate (OSBA St. No. 1, pp. 11-13); as discussed above, the correct rates are reflected in the Company's Rebuttal filing, Exhibit___(HSG-1R).

Solar Projects Witnesses Nolt and Lucas

Q. Have you reviewed the testimony provided by Mr. Nolt and Mr. Lucas regarding Citizens' proposed "Billing Demand" definition?

A Yes. I will address the distribution aspects of their respective testimony regarding the Company's proposal.

Q. Please summarize the Company's proposed Billing Demand calculation.

A Presently, Billing Demand is the customer's highest amount of electricity withdrawn from the system during the month, measured in 15-minute periods. Any customer on GLP-1 or GLP-3 is charged using the Billing Demand, which is the higher of the metered 15-minute peak usage during the month or 50% of the highest monthly Billing Demand during the prior 11 months. Approximately 51% of all customer bills issued for GLP-1 and GLP-3 during the year are billed using the alternative measure (i.e., 50% of the highest monthly Billing Demand during the prior 11 months) rather than the metered monthly demand

usage. The Company proposes to reflect customer generators in the Billing Demand definition, which would then set the Billing Demand at the highest of the following during any month, again measured in 15-minute periods:

- Electricity withdrawn from the system during the month; or
- 50% of the maximum electricity withdrawn from the system during the prior 11 months; or
- Nameplate capacity of generation unit.

Q. Why are the Company's proposed changes to Billing Demand appropriate?

A. Mr. Johnson discusses several reasons why these changes are appropriate, including the guidance from the Commission in the recent UGI Default Service Plan proceeding at Docket No. P-2024-3049343 and the changing expectations for the distribution system. In addition, although a small number of existing customer generators may experience a change in distribution costs, it will properly reflect their distribution cost responsibility. Under the Public Utility Code, a utility cannot maintain unreasonable distinctions in service or rates. Mr. Johnson explains in detail how the usage of the distribution system is similar by both a 400 kW manufacturing plant and a generator with a 400 kW solar array. Furthermore, if the installation of on-site customer generation and other distributed energy resources ("DER") strategies increases, the Company's proposed changes will ensure that all customers who use the system pay for the service they receive. If generators who use the system by injecting power are not charged, then only a fraction of customers (i.e., users of electricity) would pay for all the costs of the system. Mr. Nolt and Mr. Lucas' testimony clearly explains that avoiding distribution charges is a part of the incentive for their projects. However, simply not charging generators for their use of the system does not

change the Company's distribution system costs; it merely puts the burden onto other customers.

Q. Why is the usage of the distribution system for a 400 kW manufacturing plant similar to that of a generator with a 400 kW solar array?

A. The Company must stand ready to serve both of these loads, at any time, in either direction. Whether the customer is drawing 400 kW from the grid, or injecting 400 kW, the Company needs the same assets to serve the customer's needs.

Q. Does the presence of DER and other new technologies change the cost allocation methodology?

A. No. The purpose of cost allocation is to assign cost responsibility among the users of the system. Mr. Lucas' opinion that Citizens' proposal is not in accord with the traditional "billing demand" as used in distribution ratemaking (i.e., the amount that the account imports from the utility) is incorrect. The important consideration is not the direction of the power flow; the important consideration is the assets to be built, operated and maintained to meet the customers' needs, regardless of whether they are consumers or providers of power. The generator/exporter is using the system to accept its output and is relying on the system just as a power importer is using the system.

Mr. Lucas' and Mr. Nolt's testimonies raise important considerations regarding how the costs of the distribution system should be allocated between customers who adopt technologies like DER and customers who do not. Although the technology adopters may want to avoid distribution cost responsibility, the system must be designed, maintained and operated to meet their requirements, as well as those of all other customers. Having fewer customers paying for the system means that more of the costs would be borne by customers

that do not adopt the new technologies. The Company must continue to build, operate and maintain the system to accommodate the technology adopters. The costs to do so will not decrease; however, if the technology-adopters are able to avoid all or some of their cost responsibility, the larger cost burden would be paid by the remaining (non-technology adopting) customers. The Commission relies on cost of service and ratemaking considerations to address the important issue of how the users of the distribution system should share in its costs.

Q. On page 17 of his testimony, Mr. Lucas states, "the actual impact of most [behind the meter] DER systems is limited to a small portion of the power grid that serves the customer generator and their neighbors." Is this relevant for ratemaking purposes?

A. No. The entire distribution system, with its multiple paths and redundancies, is designed and operated to provide safe and reliable service to customers whenever it is needed. Citizens' rates are designed to recover its costs for the entire distribution system, from all its customers. The only exception is where a customer uses only dedicated assets and those assets are not used by other customers, and a directly-assigned rate is developed; that is not the case here.

Q. Mr. Nolt and Mr. Lucas assert that there will be large changes to distribution charges under the proposal. Would ratemaking principles support phasing-in the change to Billing Demand?

A. Yes. A consideration in rate design is to mitigate extreme impacts and to make changes gradually. If the impact of this change on generator bills is significant, as Mr. Nolt and Mr. Lucas claim, then phasing in the change over a number of years would be a reasonable

approach. This does not change the fact that customer generators bear cost responsibility for the assets the Company must have in order to fulfill its obligation to serve them.

Q. Would it be reasonable to measure Billing Demand using actual data, instead of nameplate maximum capacity?

A Yes, this would be reasonable too. This would be similar to the approach used for electricity consumers; however, there are distinctions that could support using the generator capacity as Citizens' has proposed. For customers who use the distribution system solely to withdraw power, it is not practical to compute the potential maximum they could withdraw, and likely not meaningful; first, customers can add machines or appliances at any time; and second, it is unlikely that all machines or appliances would be used at once.

For generators, though, the maximum potential use of the distribution system is knowable, and it is reasonable to expect the generator will use all its capacity at some time; after all, that is why it is there. However, a parallel treatment to electricity consumers, measuring Billing Demand based on actual data, could be reasonable subject to other considerations, such as metering capability and the net metering implementation discussed by Mr. Johnson.

Q. Please summarize the discussion of the testimonies of Mr. Nolt and Mr. Lucas.

A. The Company's proposed charge to Billing Demand reflects well-established principles of cost causation. The Company must stand ready to serve both a customer that draws 400 kW from the grid, and a generator that injects 400 kW; the Company uses the same distribution system to serve both. Simply not charging generators for their use of the system does not change the Company's distribution system costs; it merely puts the burden

onto other customers. Therefore, the Company's proposed Billing Demand charge is appropriate.

Q. Does this conclude your rebuttal testimony today?

A. Yes.

BEFORE

THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	**:**	
	:	
v.	**:**	**Docket No. R-2025-3054394**
	:	
Citizens' Electric Company of Lewisburg, PA	**:**	

EXHIBIT

OF

HOWARD S. GORMAN

ON BEHALF OF

CITIZENS' ELECTRIC COMPANY OF LEWISBURG, PA

AUGUST 13, 2025

A (R)

Citizens' Electric Company of Lewisburg
Rate Case with Fully Projected Future Test Year 2026 (R)
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A (R)

Citizens' Electric Company of Lewisburg
Rate Case with Fully Projected Future Test Year 2026 (R)
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Citizens' Electric Company of Lewisburg
Rate Case with Fully Projected Future Test Year 2026 (R)

Operating Revenues at Present Rates
12/31/2024, 12/31/2025 and 12/31/2026

Answer to 52 Pa. Code 53.52 b[2]

					Present Rates	Present Rates
		HY 2024 Revenue Per Bill Analysis	HY 2024 GSSR and other eliminations	HY 2024 Distribution Only	FTY 2025 Distribution Only	FPFTY 2026 Distribution Only
1	**Customer Type**	B1 (R)	B1 (R)		B2-1 (R)	B3-1 (R)
2	Residential	$2,870,229		$2,870,229	$3,887,618	$3,903,746
3	Commercial and Industrial	1,889,643		1,889,643	2,009,146	2,010,022
4	Lighting	141,375		141,375	141,375	141,375
5		4,901,247	0	4,901,247	6,038,139	6,055,143
6						
7	Forfeited Discounts	28,404		28,404	34,993	35,091
8	Rent from Electric Property	56,782		56,782	58,485	60,240
9	Other electric revenue	14,038		14,038	14,038	14,038
10	GSSR billed	10,504,818	(10,504,818)	0		
11	GSSR over/ under		0	0		
12	Unbilled revenue		0	0		
13	STAS billed	(2,023)	2,023	0		
14	Rounding	875,147	(875,147)	0		
15	**Total Operating Revenues**	$16,378,412	($11,377,941)	$5,000,471	$6,145,655	$6,164,512
16						
17	kWh Delivered					
18	Residential	57,386,200		57,386,200	87,301,973	87,664,162
19	Commercial and Industrial	46,312,631		46,312,631	73,709,507	73,990,507
20	Lighting	182,997		182,997	182,997	182,997
21		103,881,828		103,881,828	161,194,477	161,837,666

Citizens' Electric Company of Lewisburg
Rate Case with Fully Projected Future Test Year 2026 (R)

Summary Of Electric Sales, Customers And Revenue At Present Rates
Historic Year 2024

Line	Description	Sales (kWh)	Average Customers	Revenue - Present Rates: Fixed Customer Charge	Variable Distribution-Energy	Variable Distribution-Demand	Distribution Total
1	Residential Customers						
2	RS	57,386,200	5,964	$937,462	$1,932,767	$0	$2,870,229
3		57,386,200	5,964	937,462	1,932,767	0	2,870,229
4							
5	Commercial and Industrial Customers						
6	GLP 1	17,560,341	1,130	216,992	169,106	611,814	997,912
7	GLP 3	28,674,885	40	26,235	61,326	799,927	887,487
8	SH	77,405	3	828	3,416	0	4,244
9		46,312,631	1,173	244,055	233,848	1,411,741	1,889,643
10							
11	MBL	49,526	13	26,151	0	0	26,151
12	OL	133,471	26	115,224	0	0	115,224
13	Lighting	182,997	39	141,375	0	0	141,375
14							
15	TOTAL	103,881,828	7,176	$1,322,892	$2,166,615	$1,411,741	$4,901,247

Citizens' Electric Company of Lewisburg
Rate Case with Fully Projected Future Test Year 2026 (R)
Billing Units, Rates And Revenue At Present Rates
Historic Year 2024

		Residential	Space Heating	GLP-1	GLP-3	Municipal Boulevard	Outdoor Lighting	Total
1					**BILLING UNITS**			
2	kWh Sales	57,386,200	77,405	17,560,341	28,674,885	49,526	133,471	103,881,828
3								
4	Number of Bills	71,562	41	13,562	477	155	312	86,109
5	Average Monthly Bills	5,964	3	1,130	40	13	26	7,176
6								
7					**Annual Billing Units- Public Lighting and Street Lighting HY 2024**			
8	Rate 1				MBL- Meter	13		
9	Rate 2				MBL- Post	535		
10	Rate 3				Monthly revenue	2,179	9,602	
11	Rate 4							
12					**RATES AND CHARGES**			
13					**Tariff Rates**			
14	Customer Charge	$13.10	$20.19	$16.00	$55.00	$3.84		
15						$3.98	Average	
16	Energy Block 1	$0.033680	$0.044130	$0.009630	$0.009490		$14.66	
17	Energy Block 2				$0.001030			
18	Reservation Chge				$2.51		Count	
19	Voltage Discount				($0.234420)		655	
20	Block 1 kWh = Demand X				30			
21	Demand Block 1			$3.74	$5.37			
22								
23					**COMPUTATION OF REVENUE**			
24	Customer Charge Revenue	937,462	828	216,992	26,235	26,151	115,224	1,322,892
25								
26	Distribution kWh Revenue	1,932,767	3,416	169,106	61,326			2,166,615
27	Distribution Demand Revenue	0	0	611,814	799,927			1,411,741
28	*Total Distribution Revenue*	1,932,767	3,416	780,920	861,252	0	0	3,578,355
29	**Total Distribution Revenue**	$2,870,229	$4,244	$997,912	$887,487	$26,151	$115,224	$4,901,247
30								
31					**BILLING UNITS- DETAIL**			
32	Block 1 kWh Sales	57,386,200	77,405	17,560,341	3,757,740	49,526	133,471	78,964,683
33	Block 2 kWh Sales				24,917,145			24,917,145
34								
35	Billed Demand kW			163,587	131,225			294,812
36	Reservation Charge- annual				150,600			150,600
37	Reservation (CR-kW)- annual				(41,529)			
38	Voltage Discount kW				58,964			58,964
39	Block 1 kWh				3,500			3,500

Citizens' Electric Company of Lewisburg
Rate Case with Fully Projected Future Test Year 2026 (R)

Summary Of Electric Sales, Customers And Revenue At Present Rates
Future Test Year 2025

Line	Description	Sales (kWh)	Average Customers	Revenue - Present Rates			
				Fixed Customer Charge	Variable Distribution-Energy	Variable Distribution-Demand	Distribution Total
1	Residential Customers						
2	RS	87,301,973	6,026	$947,287	$2,940,330	$0	$3,887,618
3		87,301,973	6,026	947,287	2,940,330	0	3,887,618
4							
5	Commercial and Industrial Customers						
6	GLP 1	27,208,762	1,137	218,304	262,020	611,814	1,092,138
7	GLP 3	46,319,138	42	27,720	79,499	801,048	908,267
8	SH	181,607	3	727	8,014	0	8,741
9		73,709,507	1,182	246,751	349,534	1,412,862	2,009,146
10							
11	MBL	49,526	13	26,151	0	0	26,151
12	OL	133,471	26	115,224	0	0	115,224
13	Lighting	182,997	39	141,375	0	0	141,375
14							
15	TOTAL	161,194,477	7,247	$1,335,413	$3,289,864	$1,412,862	$6,038,139

B2-1 (R)

Citizens' Electric Company of Lewisburg
Rate Case with Fully Projected Future Test Year 2026 (R)
Billing Units, Rates And Revenue At Present Rates
Future Test Year 2025

		Residential	GLP-1	GLP-3	Municipal Boulevard Lighting	Outdoor Lighting	Total
1				**BILLING UNITS**			
2	kWh Sales	87,301,973	27,208,762	46,319,138	49,526	133,471	161,194,477
3							
4	Number of Bills	72,312	13,644	504	156	312	86,964
5	Average Monthly	6,026	1,137	42	13	26	7,247
6							
7				**Annual Billing Units- Public Lighting and Street Lighting HY 2024**			
8	Rate 1			MBL- Meter	13		
9	Rate 2			MBL- Post	535		
10	Rate 3			Monthly revenue	2,179	9,602	
11	Rate 4						
12				**RATES AND CHARGES**			
13				**Tariff Rates**			
14	Customer Charge	$13.10	$16.00	$55.00	$3.84	Average	
15					$3.98	$14.66	
16	Energy Block 1	$0.03368	$0.00963	$0.009490		Count	
17	Energy Block 2			$0.001030		655	
18	Reservation Chge			$2.51			
19	Voltage Discount			($0.234420)			
20	Block 1 kWh = Demand X			30			
21	Demand Block 1		$3.74	$5.37			
22							
23				**COMPUTATION OF REVENUE**			
24	Customer Charge	947,287	218,304	27,720	26,151	115,224	1,335,413
25							
26	Distribution kWh	2,940,330	262,020	79,499			3,289,864
27	Distribution Dema	0	611,814	801,048			1,412,862
28	*Total Distribution*	2,940,330	873,834	880,547	0	0	4,702,726
29	**Total Distributio**	$3,887,618	$1,092,138	$908,267	$26,151	$115,224	$6,038,139
30	*HTY 2024 Actual*	*2,870,229*	*997,912*	*887,487*	*26,151*	*115,224*	*4,901,247*
31							
32	Block 1 kWh 2022			3,757,740			
33	Block 2 kWh 2022			42,561,398			
34							
35	Demand kW 2024		163,587	131,225			
36	New Customers,	29.4%		209			
37	Demand kW		163,587	131,434			295,020

B2-1 (R)

Citizens' Electric Company of Lewisburg
Rate Case with Fully Projected Future Test Year 2026 (R)
Billing Units, Rates And Revenue At Present Rates
Future Test Year 2025

		Residential	GLP-1	GLP-3	Municipal Boulevard Lighting	Outdoor Lighting	Total
38							
39	Reservation kW- monthly			150,600			150,600
40	Reservation (CR-kW)- annual			(41,529)			(41,529)
41	Voltage Discount- kW			58,964			58,964
42	Block 1 kWh			3,500			3,500
43							
44	Customers Decembe	6,001	1,137	40	13	26	7,220
45	Customers added (l	25		2			
46	Forecast Customers	6,026	1,137	42	13	26	7,220
47	Average Annual UP	14,488	23,930	1,144,553			
48	Existing Customers	6,001	1,137	40			
49	Forecast kWh 2025	86,939,784	27,208,762	45,782,138	49,526	133,471	160,295,288
50	Projected New Cust	362,189		537,000			899,189
51	Forecast kWh 2025	87,301,973	27,208,762	46,319,138	49,526	133,471	161,194,477
52							

		Residential	GLP-1	GLP-3	Municipal Boulevard	Outdoor Lighting	Total
53							
54	kWh 2024	81,722,334	25,503,850	43,289,086	75,543	213,869	150,899,872
55	kWh 2025	87,301,973	27,208,762	46,319,138	49,526	133,471	161,194,477
56	kWh 2026	87,664,162	27,208,762	46,600,138	49,526	133,471	161,837,666

Citizens' Electric Company of Lewisburg
Rate Case with Fully Projected Future Test Year 2026 (R)
Billing Units, Rates And Revenue At Present Rates
Future Test Year 2025

		Residential	GLP-1	GLP-3	Municipal Boulevard Lighting	Outdoor Lighting	Total
57	**How Were Annual Deliveries Calculated**						
58	Future Test Year 2025 Forecast	14488 kWh avg per customer 2020-24 X 6001 customers plus 25 net new customers	23930 kWh avg per customer 2020-24 X 1137 customers plus 0 net new customers	1144553 kWh avg per customer 2020-24 X 40 customers plus 2 net new customers	Same as 2024	Same as 2024	
59			Actual 2024	Actual 2024			
60							
61	Fully Projected Future Test Year 2026 Forecast	Add another 25 new customers	Same as Forecast 2025	Same as Forecast 2025	Same as Forecast 2025	Same as Forecast 2025	
62			Same as Forecast 2025	Same as Forecast 2025			
63							
64	Demand kW 2024		163,587	131,225			294,812
65	Demand kW added (lost) annual			(10,591)			(10,591)
66							
67	Average Annual UPC						
68	Annual 2020	14,723	24,544	1,175,513	8,035	13,175	
69	Annual 2021	14,911	25,044	1,263,563	7,944	11,189	
70	Annual 2022	15,193	24,951	1,146,006	7,396	9,642	
71	Annual 2023	13,906	22,546	1,048,651	6,775	9,100	
72	Annual 2024	13,704	22,566	1,089,034	5,848	8,226	
73							
74	Class kWh						
75	Annual 2020	86,340,011	26,904,157	46,726,658	96,422	315,099	160,929,804
76	Annual 2021	87,771,999	27,656,853	50,226,631	95,322	268,542	166,555,384
77	Annual 2022	89,685,593	27,805,681	45,553,749	88,750	231,408	163,910,621
78	Annual 2023	82,450,327	25,261,385	42,994,690	81,300	218,410	151,359,461
79	Annual 2024	81,722,334	25,503,850	43,289,086	75,543	213,869	150,899,872
80							
81	Average Customers						
82	Annual 2020	5,864	1,096	40	12	24	7,045
83	Annual 2021	5,886	1,104	40	12	24	7,076
84	Annual 2022	5,903	1,114	40	12	24	7,103
85	Annual 2023	5,929	1,120	41	12	24	7,130
86	Annual 2024	5,964	1,130	40	13	26	7,176

Citizens' Electric Company of Lewisburg
Rate Case with Fully Projected Future Test Year 2026 (R)

Summary Of Electric Sales, Customers And Revenue At Present Rates
Fully Projected Future Test Year 2026

Line	Description	Sales (kWh)	Average Customers	Revenue - Present Rates			
				Fixed Customer Charge	Variable Distribution-Energy	Variable Distribution-Demand	Distribution Total
1	Residential Customers						
2	RS	87,664,162	6,051	$951,217	$2,952,529	$0	$3,903,746
3		87,664,162	6,051	951,217	2,952,529	0	3,903,746
4							
5	Commercial and Industrial Customers						
6	GLP 1	27,208,762	1,137	218,304	262,020	611,814	1,092,138
7	GLP 3	46,600,138	42	27,720	79,789	801,634	909,143
8	SH	181,607	3	727	8,014	0	8,741
9		73,990,507	1,182	246,751	349,823	1,413,448	2,010,022
10							
11	MBL	49,526	13	26,151	0	0	26,151
12	OL	133,471	26	115,224	0	0	115,224
13	Lighting	182,997	39	141,375	0	0	141,375
14							
15	TOTAL	161,837,666	7,272	$1,339,343	$3,302,352	$1,413,448	$6,055,143

B3-1 (R)

Citizens' Electric Company of Lewisburg
Rate Case with Fully Projected Future Test Year 2026 (R)
Billing Units, Rates And Revenue At Present Rates
Fully Projected Future Test Year 2026

		Residential	Space Heating	GLP-1	GLP-3	Municipal Boulevard	Outdoor Lighting	Total
1					**BILLING UNITS**			
2	kWh Sales	87,664,162	181,607	27,208,762	46,600,138	49,526	133,471	161,837,666
3								
4	Number of Bills	72,612	36	13,644	504	156	312	87,264
5	Average Monthly Bills	6,051	3	1,137	42	13	26	7,272
6								
7					**Annual Billing Units- Public Lighting and Street Lighting HY 2024**			
8	Rate 1				MBL- Meter	13		
9	Rate 2				MBL- Post	535		
10	Rate 3				Monthly revenue	2,179	9,602	
11	Rate 4							
12					**RATES AND CHARGES**			
13					**Tariff Rates**			
14	Customer Charge	$13.10	$20.19	$16.00	$55.00	$3.84		
15						$3.98	Average	
16	Energy Block 1	$0.03368	$0.04413	$0.00963	$0.009490		$14.66	
17	Energy Block 2				$0.001030		Count	
18	Reservation Chge				$2.51		655	
19	Voltage Discount				($0.234420)			
20	Block 1 kWh = Demand X				30			
21	Demand Block 1			$3.74	$5.37			
22								
23					**COMPUTATION OF REVENUE**			
24	Customer Charge Revenue	951,217	727	218,304	27,720	26,151	115,224	1,339,343
25								
26	Distribution kWh Revenue	2,952,529	8,014	262,020	79,789			3,302,352
27	Distribution Demand Revenue	0	0	611,814	801,634			1,413,448
28	*Total Distribution Revenue*	2,952,529	8,014	873,834	881,423	0	0	4,715,801
29	**Total Distribution Revenue**	$3,903,746	$8,741	$1,092,138	$909,143	$26,151	$115,224	$6,055,143
30	*FTY 2025*	*3,887,618*	*8,741*	*1,092,138*	*908,267*	*26,151*	*115,224*	*6,038,139*
31								

B3-1 (R)

Citizens' Electric Company of Lewisburg
Rate Case with Fully Projected Future Test Year 2026 (R)
Billing Units, Rates And Revenue At Present Rates
Fully Projected Future Test Year 2026

		Residential	Space Heating	GLP-1	GLP-3	Municipal Boulevard	Outdoor Lighting	Total
32	Block 1 kWh 2024				3,757,740			
33	Block 2 kWh 2024				42,842,398			
34								
35	Demand kW 2024			163,587	131,225			
36	New Customers, Load Factor	29.4%			318			
37	Demand kW			163,587	131,543			295,130
38								
39	Reservation kW- annual				150,600			150,600
40	Reservation (CR-kW)- annual				(41,529)			
41	Voltage Discount- kW				58,964			58,964
42	Block 1 kWh				3,500			3,500
43								
44	Customers December 2024	6,001	3	1,137	40	13	26	7,220
45	Customers added (lost) 2025	25	0	0	2	0	0	27
46	Customers added (lost) 2026	25						25
47	Forecast Customers 2026	6,051	3	1,137	42	13	26	7,247
48	Average Annual UPC, 2020-202	14,488	60,536	23,930	1,144,553			
49	Existing Customers	6,001	3	1,137	40	13	26	7,220
50	Forecast kWh 2026, Existing	86,939,784	181,607	27,208,762	45,782,138	49,526	133,471	160,295,288
51	Projected New Customers 2025	362,189			537,000			899,189
52	Projected New Customers 2026	362,189			281,000			643,189
53	Forecast kWh 2026	87,664,162	181,607	27,208,762	46,600,138	49,526	133,471	161,837,666
54								

B4 (R)

Citizens' Electric Company of Lewisburg
Rate Case with Fully Projected Future Test Year 2026 (R)

Distribution Revenue at Present Rates- Bill Analysis and Financial Statements
Historic Year 2024

B1

	Customer Type	Bill Analysis Revenue	GSSR	STAS	Unbilled and GSSR Over/ (Under)	Other	Revenue Computed	Revenue per 2024 Financial Statements
1	Residential	$2,870,229	$7,610,831	($1,402)	$806,708		$11,286,366	$11,286,366
2	Commercial and Industrial	1,889,643	2,866,835	(605)	69,764		4,825,636	4,825,636
3	Lighting	141,375	27,151	(15)	(1,325)		167,186	167,186
4	Distribution Revenue	4,901,247	10,504,818	(2,023)	875,147	0	16,279,188	16,279,188
5								
6	Forfeited Discounts					28,404	28,404	28,404
7	Rent from Electric Property					56,782	56,782	56,782
8	Other electric revenue					14,038	14,038	14,038
9								
10		$4,901,247	$10,504,818	-$2,023	$875,147	$99,224	$16,378,412	$16,378,412
11								

B5 (R)

Citizens' Electric Company of Lewisburg
Rate Case with Fully Projected Future Test Year 2026 (R)

Number of Customers Served Whose Bills Will be Increased
12/31/2024, 12/31/2025 and 12/31/2026
Answer to 52 Pa. Code 53.52 b[3]

		Average Number of Customers During the Year Ended		
1	**Customer Type**	**12/31/2024**	**12/31/2025**	**12/31/2026**
2	Residential	5,964	6,026	6,051
3	Commercial and Industrial (GLP-1, SH)	1,134	1,140	1,140
4	Commercial and Industrial (GLP-3)	40	42	42
5	Lighting	39	39	39
6	Total Customers Served	7,176	7,247	7,272
7				

B6 (R)

Citizens' Electric Company of Lewisburg
Rate Case with Fully Projected Future Test Year 2026 (R)

Operating Revenue Under Present Rates and Proposed Rates
12/31/2024, 12/31/2025 and 12/31/2026
Answer to 52 Pa. Code 53.52 b[4]

		Total	Distribution Only			
Line	**Description**	**HY 2024 Total Revenue**	**HY 2024**	**FTY 2025 PRESENT Rates**	**FPFTY 2026 PRESENT Rates**	**FPFTY 2026 PROPOSED Rates**
1	**Operating Revenues**	B (R)	B (R)	B (R)	B (R)	B6-1 (R)
2	Residential	$2,870,229	$2,870,229	$3,887,618	$3,903,746	$5,045,678
3	Commercial and Industrial	1,889,643	1,889,643	2,009,146	2,010,022	2,469,448
4	Lighting	141,375	141,375	141,375	141,375	182,365
5	Subtotal	4,901,247	4,901,247	6,038,139	6,055,143	7,697,492
6						
7	Forfeited Discounts	28,404	28,404	34,993	35,091	35,091
8	Rent from Electric Property	56,782	56,782	58,485	60,240	60,240
9	Other electric revenue	14,038	14,038	14,038	14,038	14,038
10	GSSR billed	10,504,818				
11	GSSR over/ under	0				
12	Unbilled revenue	0				
13	TCJA/ STAS	(2,023)				
14	Rounding	875,147				
15	Total Operating Revenues	$16,378,412	$5,000,471	$6,145,655	$6,164,512	$7,806,861
16						
17	kWh					
18	Residential	57,386,200		87,301,973	87,664,162	
19	Commercial and Industrial	46,312,631		73,709,507	73,990,507	
20	Lighting	182,997		182,997	182,997	
21		103,881,828		161,194,477	161,837,666	

Citizens' Electric Company of Lewisburg
Rate Case with Fully Projected Future Test Year 2026 (R)

Summary Of Proposed Increase to Distribution Revenue
Fully Projected Future Test Year 2026

Line	Description	Sales (kWh)	Average Customers	Distribution Total-Present Rates	Distribution - Proposed Increase	Distribution Total-Proposed Rates	% Increase Proposed
1	Residential Customers	B3	B3	B3		B6-3	
2	RS	87,664,162	6,051	3,903,746	1,141,932	5,045,678	29.3%
3		87,664,162	6,051	3,903,746	1,141,932	5,045,678	29.3%
4							
5	Commercial and Industrial Customers						
6	GLP 1	27,208,762	1,137	1,092,138	231,540	1,323,678	21.2%
7	GLP 3	46,600,138	42	909,143	225,981	1,135,125	24.9%
8	SH	181,607	3	8,741	1,904	10,645	21.8%
9		73,990,507	1,182	2,010,022	459,426	2,469,448	22.9%
10							
11	MBL	49,526	13	26,151	10,580	36,730	40.5%
12	OL	133,471	26	115,224	30,411	145,635	26.4%
13	Lighting	182,997	39	141,375	40,990	182,365	29.0%
14							
15	TOTAL	161,837,666	7,272	$6,055,143	$1,642,348	$7,697,492	27.12%

Citizens' Electric Company of Lewisburg
Rate Case with Fully Projected Future Test Year 2026 (R)

Summary Of Electric Sales, Customers And Revenue At Proposed Rates
Fully Projected Future Test Year 2026

Line	Description	Sales (kWh)	Average Customers	Revenue - Proposed Rates			
				Fixed Customer Charge	Variable Distribution-Energy	Variable Distribution-Demand	Distribution Total
1	Residential Customers						
2	RS	87,664,162	6,051	$1,198,098	$3,847,580	$0	$5,045,678
3		87,664,162	6,051	1,198,098	3,847,580	0	5,045,678
4							
5	Commercial and Industrial Customers						
6	GLP 1	27,208,762	1,137	286,524	265,558	771,597	1,323,678
7	GLP 3	46,600,138	42	50,400	99,796	984,929	1,135,125
8	SH	181,607	3	864	9,781	0	10,645
9		73,990,507	1,182	337,788	375,135	1,756,526	2,469,448
10							
11	MBL	49,526	13	36,730	0	0	36,730
12	OL	133,471	26	145,635	0	0	145,635
13	Lighting	182,997	39	182,365	0	0	182,365
14							
15	TOTAL	161,837,666	7,272	$1,718,251	$4,222,715	$1,756,526	$7,697,492

Citizens' Electric Company of Lewisburg
Rate Case with Fully Projected Future Test Year 2026 (R)
Billing Units, Rates And Revenue At Proposed Rates
Fully Projected Future Test Year 2026

		Residential	Space Heating	GLP-1	GLP-3	Municipal Boulevard Lighting	Outdoor Lighting	Total
1					**BILLING UNITS**			
2	kWh Sales	87,664,162	181,607	27,208,762	46,600,138	49,526	133,471	161,837,666
3								
4	Number of Bills	72,612	36	13,644	504	156	312	87,264
5	Average Monthly Bills	6,051	3	1,137	42	13	26	7,272
6								
7					**Annual Billing Units- Public Lighting and Street Lighting HY 2024**			
8	Rate 1				MBL- Meter	13		
9	Rate 2				MBL- Post	535		
10	Rate 3				Monthly revenue	3,061	12,136	
11	Rate 4							
12					**PROPOSED RATES AND CHARGES**			
13					**Tariff Rates**			
14	Customer Charge	$16.50	$24.00	$21.00	$100.00	$5.40		
15						$5.59	Average	
16	Energy Block 1	$0.04389	$0.05386	$0.00976	$0.01185		$18.53	
17	Energy Block 2				$0.00129		Count	
18	Reservation Chge				$3.13		655	
19	Voltage Discount				($0.29278)			
20	Block 1 kWh = Demand X				30			
21	Demand Block 1			$3.79	$6.71			
22								
23					**COMPUTATION OF REVENUE**			
24	Customer Charge Revenue	1,198,098	864	286,524	50,400	36,730	145,635	1,718,251
25								
26	Distribution kWh Revenue	3,847,580	9,781	265,558	99,796			4,222,715
27	Distribution Demand Revenue			771,597	984,929			1,756,526
28	*Total Distribution Revenue*	3,847,580	9,781	1,037,154	1,084,725	0	0	5,979,240
29	**Total Distribution Revenue**	$5,045,678	$10,645	$1,323,678	$1,135,125	$36,730	$145,635	$7,697,492
30	Target Revenue Target	5,045,655	10,645	1,323,381	1,134,562	36,755	145,631	7,696,629
31					**BILLING UNITS- DETAIL**			
32	Block 1 kWh	87,664,162	181,607	27,208,762	3,757,740	49,526	133,471	118,995,267
33	Block 2 kWh				42,842,398			42,842,398
34								
35	Demand kW	Below, Line 44		203,588	133,103			336,691
36	Reservation kW- monthly				150,600			150,600
37	Reservation (CR-kW)- annual				(41,529)			
38	Voltage Discount- kW				58,964			58,964
39	Block 1 kWh				3,500			3,500
40								
41	Calculation of Billed Demand:							
42	Demand Present Method	B3-1 (R) Line 37		163,587	131,543			
43	Increase in Billed Demand			40,001	1,560			
44	Demand Proposed Method			203,588	133,103			
45								

Citizens' Electric Company of Lewisburg
Rate Case with Fully Projected Future Test Year 2026 (R)
Proposed Revenue Allocation
FPFTY 2026

Line	Account	Balance	Residential	Space Heating	GLP-1	GLP-3	MBL	OL
				PRESENT RATES				
1	Distribution Revenue	6,055,143	3,903,746	8,741	1,092,138	909,143	26,151	115,224
2	Forfeited Disc / Other Rev	109,369	71,377	156	17,808	18,707	256	1,064
3	**Total Revenue**	6,164,512	3,975,123	8,897	1,109,947	927,850	26,407	116,289
4	Expenses	5,833,058	3,942,466	7,374	902,209	832,175	54,750	94,084
5	Net income	331,455	32,657	1,523	207,738	95,676	(28,343)	22,204
6	Rate Base	17,199,344	11,466,975	21,100	2,616,738	2,367,878	282,654	443,999
7	Return on Rate Base	1.93%	0.28%	7.22%	7.94%	4.04%	(10.03%)	5.00%
8	Relative Return	1.00 x	0.15 x	3.75 x	4.12 x	2.10 x	(5.20) x	2.60 x
9								
10				**FULLY ALLOCATED COST OF SERVICE**				
11	Distribution Revenue	7,696,489	5,198,352	9,570	1,174,501	1,082,124	88,966	142,976
12	Forfeited Disc / Other Revenue	109,369	71,377	156	17,808	18,707	256	1,064
13	Revenue Requirement	7,805,858	5,269,729	9,726	1,192,309	1,100,832	89,222	144,040
14								
15	Operating expenses	5,486,333	3,719,387	6,872	839,146	780,148	53,332	87,448
16	GRT	454,093	306,639	565	69,353	63,865	5,234	8,436
17	Income taxes	405,208	270,156	497	61,649	55,786	6,659	10,460
18	Net income	1,460,224	973,546	1,791	222,161	201,033	23,997	37,696
19	Return on Rate Base	8.49%	8.49%	8.49%	8.49%	8.49%	8.49%	8.49%
20	Revenue Increase Required	1,641,345	1,294,606	829	82,363	172,981	62,816	27,751
21	Revenue Increase %	27.11%	33.16%	9.48%	7.54%	19.03%	240.21%	24.08%
22								
23				**PROPOSED REVENUE ALLOCATION**				
24	**Distribution Revenue**	**7,696,629**	**5,045,655**	**10,645**	**1,323,381**	**1,134,562**	**36,755**	**145,631**
25	Other Revenue	109,369	71,377	156	17,808	18,707	256	1,064
26	Revenue Requirement	7,805,998	5,117,032	10,801	1,341,189	1,153,269	37,011	146,695
27								
28	Operating expenses	5,486,333	3,719,387	6,872	839,146	780,148	53,332	87,448
29	GRT	454,101	297,694	628	78,079	66,939	2,169	8,592
30	Income taxes	405,236	238,930	717	92,093	66,509	(4,016)	11,003
31	Net income	1,460,327	861,021	2,584	331,870	239,673	(14,473)	39,652
32	**Return on Rate Base**	**8.49%**	**7.51%**	**12.25%**	**12.68%**	**10.12%**	**(5.12%)**	**8.93%**
33	**Relative Return**	**1.00 x**	**0.88 x**	**1.44 x**	**1.49 x**	**1.19 x**	**(0.60) x**	**1.05 x**
34	**Progress toward unity**		**86%**	**84%**	**84%**	**82%**	**74%**	**97%**
35								
36	**Proposed Distribution Increase**	**1,641,485**	**1,141,909**	**1,904**	**231,243**	**225,419**	**10,604**	**30,407**
37	**Distribution Revenue Increase %**	**27.1%**	**29.3%**	**21.8%**	**21.2%**	**24.8%**	**40.6%**	**26.4%**
38	Total Bill Increase (100% GSSR)	8.2%	9.9%	7.8%	6.7%	4.5%	34.8%	24.0%
39	Proposed Increase		29.25%	21.78%	21.17%	24.79%	40.55%	26.39%
40	**Relative Increase**	**1.00 x**	**1.08 x**	**0.80 x**	**0.78 x**	**0.91 x**	**1.50 x**	**0.97 x**
41	*Relative Increase- Original Filing*	*1.00 x*	*1.08 x*	*0.80 x*	*0.77 x*	*0.91 x*	*2.53 x*	*0.97 x*
42	**Subsidy given (received)**							
43	Present rates	(0)	(188,327)	1,116	157,310	50,044	(33,791)	13,648
44	Proposed revene allocation	0	(112,594)	793	109,694	38,626	(38,472)	1,954
45	**Reduction in subsidy**		**40%**	**29%**	**30%**	**23%**	**(14%)**	**86%**

Citizens' Electric Company of Lewisburg
Rate Case with Fully Projected Future Test Year 2026 (R)

Summary Of Present And Proposed Rates
Fully Projected Future Test Year 2026

Line	Description	Present Rates (excl GSSR)	GSSR	Present Rates (incl GSSR)	Proposed Rates (excl GSSR)	GSSR	Proposed Rates (incl GSSR present)	Proposed Increase (excl GSSR)	Proposed Increase (incl GSSR present)
1	**Schedule RS- Residential Service**								
2	Customer Charge per Bill	$13.10		$13.10	$16.50		$16.50	26.0%	
3									
4	Energy Charge, per kWh- All	$0.03368	$0.086950	$0.12063	$0.04389	$0.086950	$0.13084	30.3%	8.5%
5	**Schedule SH- Space Heating**								
6	Customer Charge per Bill	$20.19		$20.19	$24.00		$24.00	18.9%	
7	Energy Charge, per kWh- All	$0.04413	$0.08695	$0.13108	$0.05386	$0.08695	$0.14081	22.0%	7.4%
8	**Schedule GLP-1**								
9	Customer Charge per Bill	$16.00		$16.00	$21.00		$21.00	31.3%	
10									
11	Energy Charge, All kWh	$0.009630	$0.086950	$0.09658	$0.009760	$0.086950	$0.09671	1.3%	0.1%
12									
13	Demand Charge, per kW-Mth	$3.74		$3.74	$3.79		$3.79	1.3%	1.3%
14	**Schedule GLP-3**								
15	Customer Charge per Bill	$55.00		$55.00	$100.00		$100.00	81.8%	
16									
17	Energy Charge, per kWh								
18	First 30 kWh X Billed Demand kW	$0.009490	$0.086950	$0.0964	$0.011850	$0.086950	$0.09880	24.9%	2.4%
19	Additional kWh	$0.001030	$0.086950	$0.0880	$0.001290	$0.086950	$0.08824	25.2%	0.3%
20	Reservation Charge per kW-Mth	$2.51		$2.51	$3.13		$3.13	24.7%	24.7%
21	Voltage Discount per kWh	($0.234420)		($0.234420)	($0.292780)		($0.292780)	24.9%	24.9%
22	Demand Charge, per kW-Mth	$5.37		$5.37	$6.71		$6.71	25.0%	25.0%
23	**Schedule MBL**								
24	MBL- Meter	$3.84			$5.40				
25	MBL- Post	$3.98			$5.59				
26	**Schedule OL**								
27	OL 175W MV OH Open	$7.27	49		$9.19				
28	OL 175W MV UG Cobra	$14.77	7		$18.67				
29	OL 100W HPS OH	$9.09	24		$11.49				
30	OL 100W HPS UG	$14.77	13		$18.67				
31	OL 100W HPS Colonial	$21.88	0		$27.65				
32	OL 400W HPS OH Cobra	$14.20	3		$17.95				
33	LED 15K Lum OH Cobra	$16.25	23		$20.54				
34	LED 5K Lum OH Cobra	$12.92	409		$16.33				
35	LED 5K Lum UG Colonial	$26.60	76		$33.62				
36	LED 5K Lum UG Cobra	$18.84	29		$23.81				
37	LED 20K Lum OH Cobra	$20.51	17		$25.92				
38	LED 20K Lum UG Cobra	$26.40	1		$33.37				
39	LED 15K Lum UG Cobra	$22.14	4		$27.98				
40	Average	$14.66	655		$18.53				
	Monthly $	$115,224			$145,635				

B8 (R)

Citizens' Electric Company of Lewisburg
Rate Case with Fully Projected Future Test Year 2026 (R)
Bill Comparisons (including GSSR present rate)
Fully Projected Future Test Year 2026

Schedule RS- Residential Service

			Present Rates		Proposed Rates		Proposed Increase	
	Average	Sales (kWh)	Monthly Bill	Cost per kWh	Monthly Bill	Cost per kWh	$ per Monthly Bill	%
1		Minimum	$13.10		$16.50		$3.40	26.0%
2		1	13.22	$13.22063	16.63	$16.63084	3.41	25.8%
3		100	25.16	$0.25163	29.58	0.29584	4.42	17.6%
4		250	43.26	$0.17303	49.21	0.19684	5.95	13.8%
5		500	73.42	$0.14683	81.92	0.16384	8.51	11.6%
6		700	97.54	$0.13934	108.09	0.15441	10.55	10.8%
7		1,000	133.73	$0.13373	147.34	0.14734	13.61	10.2%
8	All Residential, annual	1,250	163.89	$0.13111	180.05	0.14404	16.16	9.9%
9		1,500	194.05	$0.12936	212.76	0.14184	18.72	9.6%
10		2,000	254.36	$0.12718	278.18	0.13909	23.82	9.4%
11		3,000	374.99	$0.12500	409.02	0.13634	34.03	9.1%
12								

Schedule SH- Space Heating

			Present Rates		Proposed Rates		Proposed Increase	
15	Average	Sales (kWh)	Monthly Bill	Cost per kWh	Monthly Bill	Cost per kWh	$ per Monthly Bill	%
16		Minimum	$20.19		$24.00		$3.81	18.9%
17		1	20.32	$20.32108	24.14	$24.14081	3.82	18.8%
18		100	33.30	0.33298	38.08	0.38081	4.78	14.4%
19		250	52.96	0.21184	59.20	0.23681	6.24	11.8%
20		500	85.73	0.17146	94.41	0.18881	8.68	10.1%
21		1,000	151.27	0.15127	164.81	0.16481	13.54	9.0%
22		1,500	216.81	0.14454	235.22	0.15681	18.41	8.5%
23		2,500	347.89	0.13916	376.03	0.15041	28.14	8.1%
24		3,400	465.86	0.13702	502.75	0.14787	36.89	7.9%
25	All SH, annual	5,000	675.59	0.13512	728.05	0.14561	52.46	7.8%
26		7,000	937.75	0.13396	1,009.67	0.14424	71.92	7.7%
27								

B8 (R)

Citizens' Electric Company of Lewisburg
Rate Case with Fully Projected Future Test Year 2026 (R)
Bill Comparisons (including GSSR present rate)
Fully Projected Future Test Year 2026

Schedule GLP-1

		Present Rates		Proposed Rates		Proposed Increase	
	Sales (kWh)	Monthly Bill	Cost per kWh	Monthly Bill	Cost per kWh	$ per Monthly Bill	%
7 kW	0	42.18		47.53		5.35	12.7%
Load factor 10%	511	91.53	0.17912	96.95	0.18972	5.42	5.9%
Load factor 20%	1,022	140.88	0.13785	146.37	0.14322	5.48	3.9%
Load factor 35%	1,789	214.91	0.12016	220.50	0.12329	5.58	2.6%
Load factor 50%	2,555	288.94	0.11309	294.62	0.11531	5.68	2.0%
Load factor 60%	3,066	338.29	0.11034	344.04	0.11221	5.75	1.7%
Load factor 75%	3,833	412.32	0.10759	418.17	0.10911	5.85	1.4%
10 kW Demand	0	53.40		58.90		5.50	10.3%
Load factor 10%	730	123.90	0.16973	129.50	0.17739	5.59	4.5%
Load factor 20%	1,460	194.41	0.13316	200.10	0.13705	5.69	2.9%
Load factor 35%	2,555	300.16	0.11748	305.99	0.11976	5.83	1.9%
Load factor 50%	3,650	405.92	0.11121	411.89	0.11285	5.97	1.5%
Load factor 60%	4,380	476.42	0.10877	482.49	0.11016	6.07	1.3%
Load factor 75%	5,475	582.18	0.10633	588.39	0.10747	6.21	1.1%
25 kW Demand	0	109.50		115.75		6.25	5.7%
Load factor 10%	1,825	285.76	0.15658	292.25	0.16013	6.49	2.3%
Load factor 20%	3,650	462.02	0.12658	468.74	0.12842	6.72	1.5%
Load factor 35%	6,388	726.40	0.11372	733.49	0.11483	7.08	1.0%
Load factor 50%	9,125	990.79	0.10858	998.23	0.10939	7.44	0.8%
Load factor 60%	10,950	1,167.05	0.10658	1,174.72	0.10728	7.67	0.7%
Load factor 75%	13,688	1,431.44	0.10458	1,439.47	0.10517	8.03	0.6%
40 kW Demand	0	165.60		172.60		$7.00	4.2%
Load factor 10%	2,920	447.61	0.15329	454.99	0.15582	7.38	1.7%
Load factor 20%	5,840	729.63	0.12494	737.39	0.12626	7.76	1.1%
Load factor 35%	10,220	1,152.65	0.11278	1,160.98	0.11360	8.33	0.7%
Load factor 50%	14,600	1,575.67	0.10792	1,584.57	0.10853	8.90	0.6%
Load factor 60%	17,520	1,857.68	0.10603	1,866.96	0.10656	9.28	0.5%
Load factor 75%	21,900	2,280.70	0.10414	2,290.55	0.10459	9.85	0.4%

Citizens' Electric Company of Lewisburg
Rate Case with Fully Projected Future Test Year 2026 (R)
Bill Comparisons (including GSSR present rate)
Fully Projected Future Test Year 2026

Schedule GLP-3

		Sales (kWh)	Present Rates		Proposed Rates		Proposed Increase	
			Monthly Bill	Cost per kWh	Monthly Bill	Cost per kWh	$ per Monthly Bill	%
Monthly Minimum			$860.50		$1,106.50		246.00	28.6%
	150 kW Demand							
Load Factors		Minimum	$860.50		$1,106.50		246.00	28.6%
	30%	32,850	3,788.71	0.11533	4,052.70	0.12337	263.99	7.0%
	40%	43,800	4,752.09	0.10850	5,018.93	0.11459	266.84	5.6%
	50%	54,750	5,715.48	0.10439	5,985.16	0.10932	269.68	4.7%
	60%	65,700	6,678.86	0.10166	6,951.39	0.10580	272.53	4.1%
	75%	82,125	8,123.93	0.09892	8,400.73	0.10229	276.80	3.4%
	400 kW Demand							
Load Factors		Minimum	$2,203.00		$2,784.00		581.00	26.4%
	30%	87,600	10,011.57	0.11429	10,640.54	0.12147	628.98	6.3%
	40%	116,800	12,580.58	0.10771	13,217.15	0.11316	636.57	5.1%
	50%	146,000	15,149.60	0.10376	15,793.76	0.10818	644.16	4.3%
	60%	175,200	17,718.62	0.10113	18,370.37	0.10485	651.75	3.7%
	75%	219,000	21,572.14	0.09850	22,235.28	0.10153	663.14	3.1%
	750 kW Demand							
Load Factors		Minimum	$4,082.50		$5,132.50		1,050.00	25.7%
	30%	164,250	18,723.57	0.11399	19,863.52	0.12093	1,139.96	6.1%
	40%	219,000	23,540.47	0.10749	24,694.66	0.11276	1,154.19	4.9%
	50%	273,750	28,357.38	0.10359	29,525.80	0.10786	1,168.43	4.1%
	60%	328,500	33,174.28	0.10099	34,356.94	0.10459	1,182.66	3.6%
	75%	410,625	40,399.64	0.09839	41,603.65	0.10132	1,204.01	3.0%
	1500 kW Demand							
Load Factors		Minimum	$8,110.00		$10,165.00		2,055.00	25.3%
	30%	328,500	37,392.13	0.11383	39,627.04	0.12063	2,234.91	6.0%
	40%	438,000	47,025.94	0.10737	49,289.32	0.11253	2,263.38	4.8%
	50%	547,500	56,659.75	0.10349	58,951.60	0.10767	2,291.85	4.0%
	60%	657,000	66,293.56	0.10090	68,613.88	0.10444	2,320.32	3.5%
	75%	821,250	80,744.28	0.09832	83,107.30	0.10120	2,363.02	2.9%

Citizens' Electric Company of Lewisburg
Rate Case with Fully Projected Future Test Year 2026 (R)
Bill Comparisons (excluding GSSR)
Fully Projected Future Test Year 2026

Schedule RS- Residential Service

			Present Rates		Proposed Rates		Proposed Increase	
	Average	Sales (kWh)	Monthly Bill	Cost per kWh	Monthly Bill	Cost per kWh	$ per Monthly Bill	%
1		Minimum	$13.10		$16.50		$3.40	26.0%
2		1	13.13	$13.13368	16.54	$16.54389	3.41	26.0%
3		100	16.47	$0.16468	20.89	0.20889	4.42	26.9%
4		250	21.52	$0.08608	27.47	0.10989	5.95	27.7%
5		500	29.94	$0.05988	38.45	0.07689	8.51	28.4%
6		700	36.68	$0.05239	47.22	0.06746	10.55	28.8%
7		1,000	46.78	$0.04678	60.39	0.06039	13.61	29.1%
8	All Residential, annual	1,250	55.20	$0.04416	71.36	0.05709	16.16	29.3%
9		1,500	63.62	$0.04241	82.34	0.05489	18.72	29.4%
10		2,000	80.46	$0.04023	104.28	0.05214	23.82	29.6%
11		3,000	114.14	$0.03805	148.17	0.04939	34.03	29.8%
12								

Schedule SH- Space Heating

			Present Rates		Proposed Rates		Proposed Increase	
	Average	Sales (kWh)	Monthly Bill	Cost per kWh	Monthly Bill	Cost per kWh	$ per Monthly Bill	%
16		Minimum	$20.19		$24.00		$3.81	18.9%
17		1	20.23	$20.23413	24.05	$24.05386	3.82	18.9%
18		100	24.60	0.24603	29.39	0.29386	4.78	19.4%
19		250	31.22	0.12489	37.47	0.14986	6.24	20.0%
20		500	42.26	0.08451	50.93	0.10186	8.68	20.5%
21		1,000	64.32	0.06432	77.86	0.07786	13.54	21.1%
22		1,500	86.39	0.05759	104.79	0.06986	18.41	21.3%
23		2,500	130.52	0.05221	158.65	0.06346	28.14	21.6%
24		3,400	170.23	0.05007	207.12	0.06092	36.89	21.7%
25	All SH, annual	5,000	240.84	0.04817	293.30	0.05866	52.46	21.8%
26		7,000	329.10	0.04701	401.02	0.05729	71.92	21.9%
27								

Citizens' Electric Company of Lewisburg
Rate Case with Fully Projected Future Test Year 2026 (R)
Bill Comparisons (excluding GSSR)
Fully Projected Future Test Year 2026

Schedule GLP-1

			Present Rates		Proposed Rates		Proposed Increase	
		Sales (kWh)	Monthly Bill	Cost per kWh	Monthly Bill	Cost per kWh	$ per Monthly Bill	%
7 kW		0	42.18		47.53		5.35	12.7%
	Load factor 10%	511	47.10	0.09217	52.52	0.10277	5.42	11.5%
	Load factor 20%	1,022	52.02	0.05090	57.50	0.05627	5.48	10.5%
	Load factor 35%	1,789	59.40	0.03321	64.99	0.03634	5.58	9.4%
	Load factor 50%	2,555	66.78	0.02614	72.47	0.02836	5.68	8.5%
	Load factor 60%	3,066	71.71	0.02339	77.45	0.02526	5.75	8.0%
	Load factor 75%	3,833	79.09	0.02064	84.94	0.02216	5.85	7.4%
10 kW Demand		0	53.40		58.90		5.50	10.3%
	Load factor 10%	730	60.43	0.08278	66.02	0.09044	5.59	9.3%
	Load factor 20%	1,460	67.46	0.04621	73.15	0.05010	5.69	8.4%
	Load factor 35%	2,555	78.00	0.03053	83.84	0.03281	5.83	7.5%
	Load factor 50%	3,650	88.55	0.02426	94.52	0.02590	5.97	6.8%
	Load factor 60%	4,380	95.58	0.02182	101.65	0.02321	6.07	6.4%
	Load factor 75%	5,475	106.12	0.01938	112.34	0.02052	6.21	5.9%
25 kW Demand		0	109.50		115.75		6.25	5.7%
	Load factor 10%	1,825	127.07	0.06963	133.56	0.07318	6.49	5.1%
	Load factor 20%	3,650	144.65	0.03963	151.37	0.04147	6.72	4.7%
	Load factor 35%	6,388	171.01	0.02677	178.09	0.02788	7.08	4.1%
	Load factor 50%	9,125	197.37	0.02163	204.81	0.02244	7.44	3.8%
	Load factor 60%	10,950	214.95	0.01963	222.62	0.02033	7.67	3.6%
	Load factor 75%	13,688	241.31	0.01763	249.34	0.01822	8.03	3.3%
40 kW Demand		0	165.60		172.60		$7.00	4.2%
	Load factor 10%	2,920	193.72	0.06634	201.10	0.06887	7.38	3.8%
	Load factor 20%	5,840	221.84	0.03799	229.60	0.03931	7.76	3.5%
	Load factor 35%	10,220	264.02	0.02583	272.35	0.02665	8.33	3.2%
	Load factor 50%	14,600	306.20	0.02097	315.10	0.02158	8.90	2.9%
	Load factor 60%	17,520	334.32	0.01908	343.60	0.01961	9.28	2.8%
	Load factor 75%	21,900	376.50	0.01719	386.34	0.01764	9.85	2.6%

Citizens' Electric Company of Lewisburg
Rate Case with Fully Projected Future Test Year 2026 (R)
Bill Comparisons (excluding GSSR)
Fully Projected Future Test Year 2026

Schedule GLP-3

			Present Rates		Proposed Rates		Proposed Increase	
	Sales (kWh)		Monthly Bill	Cost per kWh	Monthly Bill	Cost per kWh	$ per Monthly Bill	%
Monthly Minimum			$860.50		$1,106.50		246.00	28.6%
	150 kW Demand							
Load Factors		Minimum	$860.50		$1,106.50		246.00	28.6%
30%		32,850	932.41	0.02838	1,196.40	0.03642	263.99	28.3%
40%		43,800	943.68	0.02155	1,210.52	0.02764	266.84	28.3%
50%		54,750	954.96	0.01744	1,224.65	0.02237	269.69	28.2%
60%		65,700	966.24	0.01471	1,238.77	0.01885	272.53	28.2%
75%		82,125	983.16	0.01197	1,259.96	0.01534	276.80	28.2%
	400 kW Demand							
Load Factors		Minimum	$2,203.00		$2,784.00		581.00	26.4%
30%		87,600	2,394.75	0.02734	3,023.72	0.03452	628.98	26.3%
40%		116,800	2,424.82	0.02076	3,061.39	0.02621	636.57	26.3%
50%		146,000	2,454.90	0.01681	3,099.06	0.02123	644.16	26.2%
60%		175,200	2,484.98	0.01418	3,136.73	0.01790	651.75	26.2%
75%		219,000	2,530.09	0.01155	3,193.23	0.01458	663.14	26.2%
	750 kW Demand							
Load Factors		Minimum	$4,082.50		$5,132.50		1,050.00	25.7%
30%		164,250	4,442.03	0.02704	5,581.98	0.03398	1,139.96	25.7%
40%		219,000	4,498.42	0.02054	5,652.61	0.02581	1,154.19	25.7%
50%		273,750	4,554.81	0.01664	5,723.24	0.02091	1,168.43	25.7%
60%		328,500	4,611.21	0.01404	5,793.87	0.01764	1,182.66	25.7%
75%		410,625	4,695.79	0.01144	5,899.81	0.01437	1,204.01	25.6%
	1500 kW Demand							
Load Factors		Minimum	$8,110.00		$10,165.00		2,055.00	25.3%
30%		328,500	8,829.06	0.02688	11,063.97	0.03368	2,234.91	25.3%
40%		438,000	8,941.84	0.02042	11,205.22	0.02558	2,263.38	25.3%
50%		547,500	9,054.63	0.01654	11,346.48	0.02072	2,291.85	25.3%
60%		657,000	9,167.41	0.01395	11,487.73	0.01749	2,320.32	25.3%
75%		821,250	9,336.59	0.01137	11,699.61	0.01425	2,363.03	25.3%

B8-2 (R)

Citizens' Electric Company of Lewisburg
Rate Case with Fully Projected Future Test Year 2026 (R)
Bill Comparisons (including GSSR effective June 1, 2025)
Fully Projected Future Test Year 2026

Schedule RS- Residential Service

			Present Rates		Proposed Rates		Proposed Increase	
	Average	Sales (kWh)	Monthly Bill	Cost per kWh	Monthly Bill	Cost per kWh	$ per Monthly Bill	%
1		Minimum	$13.10		$16.50		$3.40	26.0%
2		1	13.25	$13.24787	16.66	$16.65808	3.41	25.7%
3		100	27.89	$0.27887	32.31	0.32308	4.42	15.9%
4		250	50.07	$0.20027	56.02	0.22408	5.95	11.9%
5		500	87.04	$0.17407	95.54	0.19108	8.51	9.8%
6		700	116.61	$0.16658	127.16	0.18165	10.55	9.0%
7		1,000	160.97	$0.16097	174.58	0.17458	13.61	8.5%
8	All Residential, annual	1,250	197.94	$0.15835	214.10	0.17128	16.16	8.2%
9		1,500	234.91	$0.15660	253.62	0.16908	18.72	8.0%
10		2,000	308.84	$0.15442	332.66	0.16633	23.82	7.7%
11		3,000	456.71	$0.15224	490.74	0.16358	34.03	7.5%
12								

Schedule SH- Space Heating

			Present Rates		Proposed Rates		Proposed Increase	
14								
15	Average	Sales (kWh)	Monthly Bill	Cost per kWh	Monthly Bill	Cost per kWh	$ per Monthly Bill	%
16		Minimum	$20.19		$24.00		$3.81	18.9%
17		1	20.35	$20.34832	24.17	$24.16805	3.82	18.8%
18		100	36.02	0.36022	40.81	0.40805	4.78	13.3%
19		250	59.77	0.23908	66.01	0.26405	6.24	10.4%
20		500	99.35	0.19870	108.03	0.21605	8.68	8.7%
21		1,000	178.51	0.17851	192.05	0.19205	13.54	7.6%
22		1,500	257.67	0.17178	276.08	0.18405	18.41	7.1%
23		2,500	415.99	0.16640	444.13	0.17765	28.13	6.8%
24		3,400	558.48	0.16426	595.37	0.17511	36.89	6.6%
25	All SH, annual	5,000	811.79	0.16236	864.25	0.17285	52.46	6.5%
26		7,000	1,128.43	0.16120	1,200.35	0.17148	71.92	6.4%
27								

B8-2 (R)

Citizens' Electric Company of Lewisburg
Rate Case with Fully Projected Future Test Year 2026 (R)
Bill Comparisons (including GSSR effective June 1, 2025)
Fully Projected Future Test Year 2026

Schedule GLP-1

	Sales (kWh)	Present Rates		Proposed Rates		Proposed Increase	
		Monthly Bill	Cost per kWh	Monthly Bill	Cost per kWh	$ per Monthly Bill	%
7 kW	0	42.18		47.53		5.35	12.7%
Load factor 10%	511	105.45	0.20636	110.87	0.21696	5.42	5.1%
Load factor 20%	1,022	168.72	0.16509	174.21	0.17046	5.48	3.3%
Load factor 35%	1,789	263.63	0.14740	269.21	0.15053	5.58	2.1%
Load factor 50%	2,555	358.54	0.14033	364.22	0.14255	5.68	1.6%
Load factor 60%	3,066	421.81	0.13758	427.56	0.13945	5.75	1.4%
Load factor 75%	3,833	516.72	0.13483	522.57	0.13635	5.85	1.1%
10 kW Demand	0	53.40		58.90		5.50	10.3%
Load factor 10%	730	143.79	0.19697	149.38	0.20463	5.59	3.9%
Load factor 20%	1,460	234.18	0.16040	239.87	0.16429	5.69	2.4%
Load factor 35%	2,555	369.76	0.14472	375.59	0.14700	5.83	1.6%
Load factor 50%	3,650	505.34	0.13845	511.32	0.14009	5.97	1.2%
Load factor 60%	4,380	595.73	0.13601	601.80	0.13740	6.07	1.0%
Load factor 75%	5,475	731.31	0.13357	737.53	0.13471	6.21	0.9%
25 kW Demand	0	109.50		115.75		6.25	5.7%
Load factor 10%	1,825	335.47	0.18382	341.96	0.18737	6.49	1.9%
Load factor 20%	3,650	561.44	0.15382	568.17	0.15566	6.72	1.2%
Load factor 35%	6,388	900.40	0.14096	907.48	0.14207	7.08	0.8%
Load factor 50%	9,125	1,239.36	0.13582	1,246.79	0.13663	7.44	0.6%
Load factor 60%	10,950	1,465.33	0.13382	1,473.00	0.13452	7.67	0.5%
Load factor 75%	13,688	1,804.29	0.13182	1,812.32	0.13241	8.03	0.5%
40 kW Demand	0	165.60		172.60		$7.00	4.2%
Load factor 10%	2,920	527.15	0.18053	534.53	0.18306	7.38	1.4%
Load factor 20%	5,840	888.71	0.15218	896.47	0.15350	7.76	0.9%
Load factor 35%	10,220	1,431.04	0.14002	1,439.37	0.14084	8.33	0.6%
Load factor 50%	14,600	1,973.37	0.13516	1,982.27	0.13577	8.90	0.5%
Load factor 60%	17,520	2,334.93	0.13327	2,344.20	0.13380	9.28	0.4%
Load factor 75%	21,900	2,877.26	0.13138	2,887.11	0.13183	9.85	0.3%

Citizens' Electric Company of Lewisburg
Rate Case with Fully Projected Future Test Year 2026 (R)
Bill Comparisons (including GSSR effective June 1, 2025)
Fully Projected Future Test Year 2026

Schedule GLP-3

			Present Rates		Proposed Rates		Proposed Increase	
		Sales (kWh)	Monthly Bill	Cost per kWh	Monthly Bill	Cost per kWh	$ per Monthly Bill	%
Monthly Minimum			$860.50		$1,106.50		246.00	28.6%
	150 kW Demand							
Load Factors		Minimum	$860.50		$1,106.50		246.00	28.6%
	30%	32,850	4,683.55	0.14257	4,947.54	0.15061	263.99	5.6%
	40%	43,800	5,945.21	0.13574	6,212.04	0.14183	266.84	4.5%
	50%	54,750	7,206.87	0.13163	7,476.55	0.13656	269.68	3.7%
	60%	65,700	8,468.52	0.12890	8,741.06	0.13304	272.53	3.2%
	75%	82,125	10,361.01	0.12616	10,637.82	0.12953	276.80	2.7%
	400 kW Demand							
Load Factors		Minimum	$2,203.00		$2,784.00		581.00	26.4%
	30%	87,600	12,397.79	0.14153	13,026.77	0.14871	628.98	5.1%
	40%	116,800	15,762.22	0.13495	16,398.78	0.14040	636.57	4.0%
	50%	146,000	19,126.64	0.13100	19,770.80	0.13542	644.16	3.4%
	60%	175,200	22,491.06	0.12837	23,142.82	0.13209	651.75	2.9%
	75%	219,000	27,537.70	0.12574	28,200.84	0.12877	663.14	2.4%
	750 kW Demand							
Load Factors		Minimum	$4,082.50		$5,132.50		1,050.00	25.7%
	30%	164,250	23,197.74	0.14123	24,337.69	0.14817	1,139.96	4.9%
	40%	219,000	29,506.03	0.13473	30,660.22	0.14000	1,154.19	3.9%
	50%	273,750	35,814.33	0.13083	36,982.75	0.13510	1,168.43	3.3%
	60%	328,500	42,122.62	0.12823	43,305.28	0.13183	1,182.66	2.8%
	75%	410,625	51,585.06	0.12563	52,789.08	0.12856	1,204.01	2.3%
	1500 kW Demand							
Load Factors		Minimum	$8,110.00		$10,165.00		2,055.00	25.3%
	30%	328,500	46,340.47	0.14107	48,575.38	0.14787	2,234.91	4.8%
	40%	438,000	58,957.06	0.13461	61,220.44	0.13977	2,263.38	3.8%
	50%	547,500	71,573.65	0.13073	73,865.50	0.13491	2,291.85	3.2%
	60%	657,000	84,190.24	0.12814	86,510.56	0.13168	2,320.32	2.8%
	75%	821,250	103,115.13	0.12556	105,478.15	0.12844	2,363.02	2.3%

Citizens' Electric Company of Lewisburg
Rate Case with Fully Projected Future Test Year 2026 (R)

Net Operating Income And Rates of Return
HY 2024, FTY 2025 and FPFTY 2026
Answer to 52 Pa. Code 53.52 c[1]

Line	Description	Present Rates HY 12/31/2024		Present Rates FTY 12/31/2025	Present Rates FPFTY 12/31/2026	Full Revenue Requirement FPFTY 12/31/2026	Proposed Rates FPFTY 12/31/2026
		Per Books	Distribution Only	Distribution Only	Distribution Only	Distribution Only	Distribution Only
1	**REVENUE**						
2	Residential	$2,870,229	$2,870,229	$3,887,618	$3,903,746		$5,045,678
3	Comm and indus	1,889,643	1,889,643	2,009,146	2,010,022		2,469,448
4	Lighting	141,375	141,375	141,375	141,375		182,365
5	Rounding						
6	Electric operating revenue	4,901,247	4,901,247	6,038,139	6,055,143	7,696,615	7,697,492
7	Other revenue, net	99,224	99,224	107,516	109,369	109,369	109,369
8	GSSR	10,504,818					
9	Other, net	873,123	873,123				
10	Total Revenue	16,378,412	5,873,594	6,145,655	6,164,512	7,805,985	7,806,861
11	*Annual kWH*	*103,881,828*	*103,881,828*	*161,194,477*	*161,837,666*	*161,837,666*	*161,837,666*
12	**EXPENSES**				Increase	1,641,472	
13	Purchased electricity	10,504,818					
14	Distribution	1,556,654	1,556,654	1,743,703	1,929,647	1,929,647	1,929,647
15	Customer acct & coll	536,669	536,669	542,259	549,379	549,379	549,379
16	Admin & general	1,268,620	1,268,620	1,328,967	1,511,606	1,511,606	1,511,606
17	Total Operating expense	13,866,761	3,361,943	3,614,929	3,990,632	3,990,632	3,990,632
18							
19	Depreciation expense	1,126,159	1,126,159	1,323,181	1,409,998	1,409,998	1,409,998
20	Adjust expenses to Financials						
21	Taxes other than income	978,426	373,470	441,195	442,957	539,804	539,805
22							
23	Total Expenses	15,971,345	4,861,571	5,379,305	5,843,586	5,940,433	5,940,434
24							
25	Net operating income before income taxes	407,067	1,012,023	766,350	320,926	1,865,551	1,866,427
26							
27	Income tax expense	121,634	172,349	120,791	(10,537)	405,231	405,467
28	NET UTILITY OPERATING INCOME	$285,433	$839,675	$645,559	$331,463	$1,460,320	$1,460,960
29							0.084937
30	RATE BASE (B)		$15,106,320	$16,220,363	$17,200,472	$17,200,472	$17,200,472
31	RATE OF RETURN ON RATE BASE (A / B)		5.56%	3.98%	1.93%	8.49%	8.49%

Citizens' Electric Company of Lewisburg
Rate Case with Fully Projected Future Test Year 2026 (R)

Net Operating Income And Rates of Return
HY 2024, FTY 2025 and FPFTY 2026
Answer to 52 Pa. Code 53.52 c[1] - Support Sheet No. 1
Support Sheet No. 1- Operating Expense and Going-Level Adjustments

Line	Acct.	Account Description	Year 2023	Year 2024	Year 2024 to Year 2025	Year 2025	Year 2025 to Year 2026	Year 2026	Labor			
									Year 2023	HY 2024	FTY 2025	FPFTY 2026
			Actual	Actual	Changes	Forecast	Changes	Forecast	Actual	Actual	Forecast	Forecast
1	Distribution Expenses											
2	580	Operations Supv & Eng	139,449	147,492	3,650	151,142	3,816	154,958	65,639	69,376	70,506	73,380
3	582	Station Expense	20,968	5,258	8,721	13,979	67	14,046	8,446	1,974	5,821	5,941
4	583	Overhead Line	242,610	226,033	8,894	234,927	7,145	242,072	106,207	80,793	99,056	101,098
5	585	Street Lighting	8,095	12,169	(7,144)	5,025	112	5,137	2,438	4,820	2,195	2,240
6	586	Meter Expense	25,262	24,042	24,916	48,958	1,754	50,712	18,234	(7,401)	22,504	22,968
7	587	Customer Installation	39,845	41,115	12,650	53,765	2,652	56,416	16,746	19,074	21,945	22,397
8	588	Miscellaneous Distribution	395,055	455,104	31,311	486,415	8,839	495,254	116,645	121,176	127,162	129,784
9	589	Rents	520	530	(5)	525	0	525	0	0	0	0
10		*Total Operating & Maintenanc*	871,804	911,743	82,992	994,735	24,385	1,019,120	334,356	289,812	349,187	357,808
11												
12	592	Maintenance of Station Equipment	2,202	25,133	(8,301)	16,832	377	17,209	1,134	11,213	7,461	7,615
13	593	Maintenance of Overhead Lines	563,525	558,565	108,646	667,211	159,625	826,836	142,193	139,744	163,850	167,068
14	594	Maintenance of Underground Line	16,532	13,331	1,030	14,361	466	14,827	6,923	5,237	6,159	6,286
15	595	Maintain Line Transformers	85,912	31,968	(5,001)	26,967	500	27,468	9,440	7,462	7,377	7,529
16	596	Maint. Street Light & Signal	22,847	15,914	7,682	23,596	591	24,187	10,192	6,283	9,176	9,365
17	597	Maintenance of Misc. Distrib Plan	0	0	0	0	0	0	0	0	0	0
18		*Total Maintenance*	691,018	644,911	104,057	748,968	161,559	910,527	169,882	169,939	194,023	197,863
19		*Total Operating & Maintenanc*	1,562,822	1,556,654	187,049	1,743,703	185,944	1,929,647	504,238	459,751	543,210	555,671
20												

Citizens' Electric Company of Lewisburg
Rate Case with Fully Projected Future Test Year 2026 (R)

Net Operating Income And Rates of Return
HY 2024, FTY 2025 and FPFTY 2026
Answer to 52 Pa. Code 53.52 c[1] - Support Sheet No. 1
Support Sheet No. 1- Operating Expense and Going-Level Adjustments

Line	Acct.	Account Description	Year 2023	Year 2024	Year 2024 to Year 2025	Year 2025	Year 2025 to Year 2026	Year 2026	Labor Year 2023	Labor HY 2024	Labor FTY 2025	Labor FPFTY 2026
21		Customer Accounting & Collection Expenses:										
22	902	Meter Reading Expense	25,085	26,338	(338)	26,000	0	26,000	0	0	0	0
23	903	Customer Records & Collection	474,976	483,001	3,258	486,259	6,220	492,479	176,064	174,418	174,043	179,475
24	904	Uncollectible Accounts	31,906	27,330	2,670	30,000	900	30,900	0	0	0	0
25		*Total Customer Accting & Coll*	531,968	536,669	5,590	542,259	7,120	549,379	176,064	174,418	174,043	179,475
26												
27		Administrative & General Expenses:										
28	920	Administrative & General Salaries	742,994	700,832	31,998	732,830	152,118	884,948	351,801	323,420	341,855	419,064
29	921	Office Supplies & Expenses	102,713	145,923	937	146,860	4,406	151,265	0	0	0	0
30	923	Outside Services Employed	47,103	40,008	(3,008)	37,000	1,110	38,110	0	0	0	0
31	924	Property Insurance	11,431	11,190	(131)	11,059	0	11,059	0	0	0	0
32	925	Injuires & Damages	27,561	27,341	1,566	28,907	0	28,907	0	0	0	0
33	926	Employee Pensions & Benefits	6,204	7,497	1,003	8,500	255	8,755	0	0	0	0
34	928	Regulatory Commission	105,515	70,128	18,080	88,208	20,681	108,889	0	0	0	0
35	930	Miscellaneous General	105,300	110,600	291	110,891	3,327	114,218	0	0	0	0
36	932	Maintenance of General Property	121,914	155,101	9,612	164,713	743	165,455	47,569	62,272	64,116	65,438
37		*Total Administrative & General*	1,270,735	1,268,620	60,347	1,328,967	182,639	1,511,606	399,370	385,692	405,971	484,503
38												
39		**Total O&M Expense**	**$3,365,525**	**$3,361,943**	**$252,986**	**$3,614,929**	**$375,702**	**$3,990,632**	**$1,079,671**	**$1,019,861**	**$1,123,224**	**$1,219,649**
40												

41			Year 2023	Year 2024	Year 2024 to Year 2025	Year 2025	Year 2025 to Year 2026	Year 2026
42		Labor	1,079,671	1,019,861	103,363	1,123,224	96,425	1,219,649
43		Overhead	1,197,394	1,239,081	45,537	1,284,618	71,296	1,355,914
44		Transportation	101,038	87,328	1,310	88,638	31,871	120,509
45		Materials	987,422	1,015,673	102,776	1,118,449	176,111	1,294,560
46			3,365,525	3,361,943	252,986	3,614,929	375,702	3,990,632

C1-2 (R)

Citizens' Electric Company of Lewisburg
Rate Case with Fully Projected Future Test Year 2026 (R)
Net Operating Income And Rates of Return
Support Sheet No. 2- Cost of Capital and Fair Rate of Return Based upon Hypothetical Ratemaking Capital Structure
12/31/2025 and 12/31/2026

				12/31/26	
Line	**Type of Capital**		**Ratios (1)**	**Cost Rate**	**Weighted Cost**
1	Long-Term Debt	(B)	51.06%	5.470%	2.79%
2	Preferred Stock				
3	Common Equity	(A)	48.94%	11.65%	5.70%
4	Total		100.00%		8.49%
5				Using	8.49000%
6					
7	(A) Recommended hypothetical capital structure ratios as discussed in direct testimony.				

C1-3 (R)

Citizens' Electric Company of Lewisburg
Rate Case with Fully Projected Future Test Year 2026 (R)

Net Operating Income And Rates of Return
HY 2024, FTY 2025 and FPFTY 2026
Answer to 52 Pa. Code 53.52 c[1]
Support Sheet No. 3- Taxes Other Than Income

Line	Description		HY 2024		Present Rates FTY 12/31/2025	Present Rates FPFTY 12/31/2026	Full Revenue Requirement FPFTY 12/31/2026	Proposed Rates FPFTY 12/31/2026
			Per Books	Distribution Only	Distribution Only	Distribution Only		Distribution Only
1	Taxes other than income:							
2	Pennsylvania Use Tax		$7,604	$7,604	$7,604	$7,604	$7,604	$7,604
3	PUC Assessment		63,038	63,038	63,038	63,038	63,038	63,038
4	Public Utility Realty Tax (including surcharge)		13,654	13,654	14,302	15,062	15,062	15,062
5	Pennsylvania Gross Receipts Tax		894,130	289,174	356,250	357,253	454,100	454,101
6			$978,426	$373,470	$441,195	$442,957	$539,804	$539,805
7								
8	**Gross Receipts Tax**							
9	Distruibution revenue		$4,901,247	$4,901,247	$6,038,139	$6,055,143	$7,696,615	$7,696,629
10	GSSR, including over/under		10,504,818					
11	Gross Receipts Taxable		$15,406,065	$4,901,247	$6,038,139	$6,055,143	$7,696,615	$7,696,629
12	Gross Receipts Tax at Present Rate	5.90%	$908,958	$289,174	$356,250	$357,253	$454,100	$454,101
13	Prior Year adjustment		(14,828)					
14	Gross Receipts Tax expense		$894,130	$289,174	$356,250	$357,253	$454,100	$454,101
15								
16	**Normalized Rate case expense**							
17	Estimated expenses					$326,667		
18	Amortization period (years)					3.0		
19	Normalized Rate case expense					108,889		
20			12/31/2023	12/31/2024	12/31/2025			
21	Rate Case 2022		147,203	80,155	80,155		Amortized by 12/31/2025	
22	POLR/PJM 2021		25,614	7,533	7,533		Amortized by 12/31/2025	
23	POLR/PJM 2024			24,893	8,298	-		
24	Normalized Rate case expense		172,817	112,581	95,986	108,889		

C1-4 (R)

Citizens' Electric Company of Lewisburg
Rate Case with Fully Projected Future Test Year 2026 (R)

Net Operating Income And Rates of Return
HY 2024, FTY 2025 and FPFTY 2026
Answer to 52 Pa. Code 53.52 c[1]
Support Sheet No. 4- Income Tax Calculations

Line	Description	Rate	HY 2024		Present Rates FTY 12/31/2025	Present Rates FPFTY 12/31/2026	Full Revenue Requirement FPFTY 12/31/2026	Proposed Rates FPFTY 12/31/2026
			Per Books	Distribution Onl	Distribution Onl	Distribution Onl	Distribution Onl	Distribution Onl
1	Net Operating Income Excluding Income Taxes		$407,067	$1,012,023	$766,350	$320,926	$1,865,551	$1,866,427
2								
3	Synchronized interest expense:							
4	Rate base		0	15,106,320	16,220,363	17,200,472	17,200,472	17,200,472
5								
6	Rate base for interest compuation		0	15,106,320	16,220,363	17,200,472	17,200,472	17,200,472
7	Weighted Cost of debt		2.793%	2.793%	2.793%	2.793%	2.793%	2.793%
8	Synchronized interest expense		0	421,917	453,031	480,406	480,406	480,406
9	Taxable income before depreciation tax adjustments		407,067	590,107	313,318	(159,480)	1,385,146	1,386,021
10								
11	Pennsylvania depreciation adjustment:							
12	Tax depreciation (using DDB method)		(1,255,863)	(1,255,863)	(1,277,811)	(1,399,256)	(1,399,256)	(1,399,256)
13	Book depreciation		1,126,159	1,126,159	1,323,181	1,409,998	1,409,998	1,409,998
14	Pennsylvania depreciation adjustment		(129,705)	(129,705)	45,370	10,742	10,742	10,742
15	Pennsylvania taxable income		277,362	460,402	358,688	(148,738)	1,395,887	1,396,762
16	Regulatory Pennsylvania income tax expense	8.99%	23,548	39,088	28,659	(11,140)	104,552	104,618
17		8.99%	8.49%	8.49%	7.99%	7.49%	7.49%	7.49%
18	Federal depreciation adjustment:							
19	Tax depreciation (using SL method with bonus depreciation		(1,042,603)	(1,042,603)	(1,169,116)	(1,258,785)	(1,258,785)	(1,258,785)
20	Book depreciation		1,126,159	1,126,159	1,323,181	1,409,998	1,409,998	1,409,998
21	Federal depreciation adjustment		83,555	83,555	154,065	151,212	151,212	151,212
22								
23	Taxable income before depreciation tax adjustments		407,067	590,107	313,318	(159,480)	1,385,146	1,386,021
24	Federal depreciation adjustment		83,555	83,555	154,065	151,212	151,212	151,212
25	Pennsylvania income tax expense		(23,548)	(39,088)	(28,659)	11,140	(104,552)	(104,618)
26	Federal taxable income (loss)		467,074	634,574	438,724	2,873	1,431,806	1,432,616
27	Regulatory Federal income tax expense (benefit)	21.00%	98,086	133,261	92,132	603	300,679	300,849
28								
29	Regulatory Total income tax expense (benefit)		$121,634	$172,349	$120,791	($10,537)	$405,231	$405,467
30								
31	Combined statutory tax rate	28.10%	27.71%	27.71%	27.31%	26.92%	26.92%	26.92%
32								

Citizens' Electric Company of Lewisburg
Rate Case with Fully Projected Future Test Year 2026 (R)

Net Operating Income And Rates of Return
HY 2024, FTY 2025 and FPFTY 2026
Answer to 52 Pa. Code 53.52 c[1]
Support Sheet No. 5- Computation of Rate Base

Line	Description	Ref.	HY 2024 Distribution	FTY 2025	FPFTY 2026
1	**Utility Plant in Service**				
2	Assets	Sch. C3 (R), line 28	$ 30,802,761	$ 32,979,090	$ 35,369,114
3	Less: Accumulated Depreciation	Sch. C3 (R), line 28	(15,229,320)	(16,666,142)	(18,189,781)
4			15,573,441	16,312,948	17,179,333
5					
6	Less: Accumulated deferred income taxes (ADIT)	Line 32	(348,561)	(337,325)	(336,658)
7					
8	Less: Customer deposits	Sch. C2 (R), line 52	(299,385)	(299,385)	(189,068)
9	Accrued Pension / OPEB Liability	Line 47	(531,221)	(207,457)	(264,804)
10	Materials & Supplies	Sch. C2 (R), line 23	303,686	303,686	328,809
11			14,697,959	15,772,467	16,717,612
12	Cash Working Capital Allowance	Line 25	408,361	447,896	482,860
13	RATE BASE		$ 15,106,320	$ 16,220,363	$ 17,200,472
14					
15	**Cash Working Capital Allowance:**				
16	Operating Expenses	Sch. C1 (R), line 23	$ 4,861,571	$ 5,379,305	$ 5,843,586
17					
18	Deductions:				
19	Taxes Other Than Income	Sch. C1-3 (R), line 6	441,195	442,957	539,805
20	Uncollectible accounts	Sch. C1-1 (R), line 24	27,330	30,000	30,900
21	Depreciation Expense	Sch. C1 (R), line 19	1,126,159	1,323,181	1,409,998
22	Total Deductions		1,594,683	1,796,139	1,980,703
23	Cash Operating Expenses		3,266,888	3,583,166	3,862,884
24	Cash Operating Expenses Ratio		1/8	1/8	1/8
25	Cash Working Capital Allowance (A plus B)		$ 408,361	$ 447,896	$ 482,860
26					
27	Regulatory Accumluated deferred income tax:				
28	Accumulated depreciation based on tax expense borne by ratepayers		21,209,863	22,378,980	23,637,765
29	Accumulated depreciation based on taxes paid by company		22,869,678	23,985,289	25,240,900
30	(Excess) depreciation taken by company		(1,659,815)	(1,606,310)	(1,603,135)
31	Federal tax rate		21.00%	21.00%	21.00%
32	Regulatory Accumluated deferred income tax (liability)		(348,561)	(337,325)	(336,658)
33					
34					
35					
36					
37					
38					
39					
40					
41					
42	Regulatoy (Liabilities) and Assets				
43	Accrued postretirement cost (Liability)		(555,864)	(555,864)	(555,864)
44	Regulatoy (Liability)		(178,954)	(178,954)	(178,954)
45	Regulatory Assets			326,667	272,222
46	Deferred tax asset related to Regulatory Liabiliti	Line 43 X 27.7%	203,597	200,694	197,792
47			(531,221)	(207,457)	(264,804)

C2 (R)

Citizens' Electric Company of Lewisburg
Rate Case with Fully Projected Future Test Year 2026 (R)

Balance Sheets
12/31/2024, 12/31/2025 and 12/31/2026
Answer to 52 Pa. Code 53.52 c[2]

Line	Account Title	Per Books 12/31/2024	Pro Forma 12/31/2025	Pro Forma 12/31/2026
1	**Assets and Other Debits**			
2	Utility Plant			
3	Electric plant in service	$30,802,761	$32,979,090	$35,369,114
4	Construction work in progress	119,314	119,314	119,314
5				
6	Accumulated depreciation	(15,229,320)	(16,666,142)	(18,189,781)
7	*Total utility plant*	15,692,755	16,432,262	17,298,647
8				
9	Other Property and Investments:			
10	Non-utility property, SV Life nsurance, other	21,704	21,704	21,704
11	Regulatory asset	112,581	112,581	112,581
12	Regulatory asset- RS Plan, Other	246,271	246,271	246,271
13	Goodwill, net	3,978,203	3,978,203	3,978,203
14	*Total other property and investments*	4,358,759	4,358,759	4,358,759
15				
16	Current Assets:			
17	Cash	553,348	553,348	553,348
18	Customer accounts receivable	1,173,451	1,173,451	1,173,451
19	Provison for uncollectible accounts		0	0
20	Accrued utility revenues	1,100,909	1,100,909	1,100,909
21	Other accounts receivable	101,732	101,732	101,732
22	Advances to affiliates	90,700	90,700	90,700
23	Inventories	303,686	303,686	328,809
24	Prepayments	31,769	31,769	31,769
25	Under collected power costs	263,044	263,044	263,044
26	Deferred income taxes		0	0
27	*Total current assets*	3,618,639	3,618,639	3,643,762
28				
29	**Total Assets and Other Debits**	**$23,670,153**	**$24,409,660**	**$25,301,168**
30				

C2 (R)

Citizens' Electric Company of Lewisburg
Rate Case with Fully Projected Future Test Year 2026 (R)

Balance Sheets
12/31/2024, 12/31/2025 and 12/31/2026
Answer to 52 Pa. Code 53.52 c[2]

Line	Account Title	Per Books 12/31/2024	Pro Forma 12/31/2025	Pro Forma 12/31/2026
31	**Liabilities and Other Credits**			
32	Proprietary Capital:			
33	Preferred stock		$0	$0
34	Common stock Issued	1,394,720	1,394,720	1,394,720
35	Retained earnings	11,728,535	12,374,094	11,579,592
36	Paid-in Capital, less Treasury Stock	859,338	859,338	859,338
37	*Total proprietary capital*	13,982,593	14,628,152	13,833,650
38				
39	Long-Term Debt:			
40	Long term debt	1,540,746	1,112,538	1,922,926
41	Capitalized Lease Obligations	432,598	89,194	0
42	*Total long-term debt*	1,973,344	1,201,732	1,922,926
43				
44	Current and Accrued Liabilities:			
45	Line of Credit	$3,300,000	$4,165,855	$5,240,988
46	Current maturities of long-term debt	108,359	108,359	108,359
47	Current maturities of capitalized leases	90,626	90,626	90,626
48	Accounts payable	366,102	366,102	366,102
49	Due for purchased electricity	839,832	839,832	839,832
50	Accrued expenses	291,139	291,139	291,139
51	Accrued taxes	38,360	38,360	38,360
52	Customer deposits	299,385	299,385	189,068
53	*Total current and accrued liabilities*	5,333,803	6,199,658	7,164,474
54				
55	Deferred Credits and Other Liabilities:			
56	Deferred income taxes	1,645,300	1,645,300	1,645,300
57	Accrued postretirement cost	555,864	555,864	555,864
58	Regulatory Liability	178,954	178,954	178,954
59	*Total deferred credits*	2,380,118	2,380,118	2,380,118
60				
61	**Total Liabilities and Other Credits**	**$23,669,858**	**$24,409,660**	**$25,301,168**

C3 (R) **Citizens' Electric Company of Lewisburg**
Rate Case with Fully Projected Future Test
Original Cost of Utility Plant in Service
12/31/2024, 12/31/2025 and 12/31/2026
Answer to 52 Pa. Code 53.52 c[3]

Line	Acct No.	Account Title	Original Cost Balance 12/31/2023	Original Cost Year 2024 Additions	Year 2024 Retire	Original Cost Balance 12/31/2024	Original Cost FTY 2025 Additions	FTY 2025 Retire	Original Cost Balance 12/31/2025	Original Cost FPFTY 2026 Additions	FPFTY 2026 Retire	Original Cost Balance 12/31/2026
1	**Depreciable Plant:**											
2	*Distribution Plant.*											
3	360	Land & Land Rights	17,040	1,254		18,294	1,066		19,360	1,098		20,458
4	361	Organization	995			995			995			995
5	362	Station Equipment	657,380		(15,868)	641,512			641,512			641,512
6	362.01	Station Equipment- Fully depr.	134,900			134,900			134,900			134,900
7	364	Poles, Tower & Fixtures	4,317,240	160,455	(31,694)	4,446,001	166,431		4,612,432	321,804		4,934,235
8	365	Overhead Conductors & Devices	8,043,524	462,968	(66,108)	8,440,384	702,430		9,142,814	723,503		9,866,317
9	366	Underground Conduit	3,485,764	180,115	(2,624)	3,663,255	197,081		3,860,336	202,993		4,063,329
10	368	Line Transformers	2,950,070	140,154	(32,422)	3,057,802	183,783		3,241,585	189,296		3,430,881
11	369	Services	4,130,180	239,595	(23,910)	4,345,865	297,378		4,643,243	306,299		4,949,542
12	370	Meters	1,478,201	260,127	(53,519)	1,684,809	56,132		1,740,941	57,816		1,798,757
13	373	Street Lighting & Signal Systems	680,950	20,177	(11,509)	689,618	64,286		753,904	66,215		820,118
14	Total Distribution Plant		25,896,244	1,464,845	(237,654)	27,123,435	1,668,586	0	28,792,021	1,869,024	0	30,661,045
15												
16	*General Plant*											
17	390.1	Structures & Improvements, office	721,358	57,058		778,416	35,465		813,881	60,942		874,823
18	391	Office Furniture & Equipment	595,278	20,301	(170,748)	444,831	37,278		482,109	64,058		546,167
19	390X	General- Fully depreciated	319,218			319,218			319,218			319,218
20	392	Transportation Equipment	1,294,630	278,419	(151,118)	1,421,931	425,000		1,846,931	386,000		2,232,931
21	394	Tools, Shop & Garage Equipment	128,054	9,237		137,291	6,525		143,816	6,525		150,340
22	395	Laboratory & Stores Equipment	105,987			105,987			105,987			105,987
23	397	Communication Equipment	405,497	23,742	(1,202)	428,037			428,037			428,037
24	398	Miscellaneous Equipment	43,615			43,615	3,475		47,090	3,475		50,566
25	301	Intangible plant, EDI	0			0			0			0
26		Total General Plant	3,613,637	388,757	(323,068)	3,679,326	507,743	0	4,187,069	521,000	0	4,708,069
27												
28		Total Plant in Service	$29,509,881	$1,853,602	($560,722)	$30,802,761	$2,176,329	$0	$32,979,090	$2,390,024	$0	$35,369,114

C3 (R) **Citizens' Electric Company of Lewisburg**
Rate Case with Fully Projected Future Test
Original Cost of Utility Plant in Service
12/31/2024, 12/31/2025 and 12/31/2026
Answer to 52 Pa. Code 53.52 c[3]

Line	Acct No.	Account Title	Accumulated Depreciation Balance 12/31/2023	Accumulated Depreciation Year 2024 Additions	Year 2024 Remove	Accumulated Depreciation Balance 12/31/2024	Accumulated Depreciation FTY 2025 Additions	Accumulated Depreciation Balance 12/31/2025	Accumulated Depreciation FPFTY 2026 Additions	Accumulated Depreciation Balance 12/31/2026	Net Book Value 12/31/2026 Pro Forma
1	**Depreciable Plant:**										
2	*Distribution Plant.*										
3	360	Land & Land Rights	0	0		0	0	0	0	0	20,458
4	361	Organization	0	0		0	0	0	0	0	995
5	362	Station Equipment	626,750	2,969	(18,064)	611,655	13,030	624,685	4,197	628,882	12,630
6	362.01	Station Equipment- Fully depr.	134,900	0		134,900	0	134,900	0	134,900	0
7	364	Poles, Tower & Fixtures	3,128,994	184,752	(84,731)	3,229,015	186,830	3,415,845	196,900	3,612,745	1,321,490
8	365	Overhead Conductors & Devices	1,985,151	328,730	(156,901)	2,156,980	351,664	2,508,644	380,183	2,888,827	6,977,490
9	366	Underground Conduit	2,142,257	141,732	(5,168)	2,278,821	150,472	2,429,293	158,473	2,587,766	1,475,563
10	368	Line Transformers	2,251,693	120,120	(32,422)	2,339,391	125,988	2,465,379	133,449	2,598,828	832,053
11	369	Services	1,776,639	167,472	(53,827)	1,890,284	179,782	2,070,066	191,856	2,261,922	2,687,620
12	370	Meters	(46,144)	63,056	(53,519)	(36,607)	68,515	31,908	70,794	102,702	1,696,055
13	373	Street Lighting & Signal Systems	59,572	46,482	(22,873)	83,182	42,598	125,780	45,208	170,989	649,130
14	Total Distribution Plant		12,059,812	1,055,314	(427,505)	12,687,621	1,118,880	13,806,501	1,181,060	14,987,561	15,673,484
15											
16	*General Plant*										
17	390.1	Structures & Improvements, office	584,566	5,379		589,945	23,884	613,829	25,331	639,160	235,663
18	391	Office Furniture & Equipment	428,049	41,164	(170,748)	298,465	37,078	335,543	35,273	370,816	175,351
19	390X	General- Fully depreciated	319,215			319,215		319,215		319,215	3
20	392	Transportation Equipment	890,038	113,641	(151,117)	852,562	204,304	1,056,866	240,786	1,297,653	935,278
21	394	Tools, Shop & Garage Equipment	77,162	8,375		85,538	14,055	99,593	14,708	114,301	36,039
22	395	Laboratory & Stores Equipment	76,319	4,915		81,234	7,065	88,300	7,065	95,365	10,622
23	397	Communication Equipment	282,702	9,256	(1,203)	290,755	28,533	319,288	16,161	335,449	92,588
24	398	Miscellaneous Equipment	21,994	1,990		23,985	3,023	27,008	3,255	30,263	20,303
25	301	Intangible plant, EDI	235	(235)		0	0	0	0	0	0
26		Total General Plant	2,680,282	184,485	(323,068)	2,541,699	317,943	2,859,641	342,579	3,202,220	1,505,849
27											
28		Total Plant in Service	$14,740,094	$1,239,800	($750,573)	$15,229,320	$1,436,822	$16,666,142	$1,523,639	$18,189,781	$17,179,333

C4 (R)

Citizens' Electric Company of Lewisburg
Rate Case with Fully Projected Future Test Year 2026 (R)

Reserve for Depreciation of Utility Plant
12/31/2024, 12/31/2025 and 12/31/2026
Answer to 52 Pa. Code 53.52 c[4]

	Account Title	Per Books 12/31/2024	Pro Forma 12/31/2025	Pro Forma 12/31/2026
1	Reserve for Depreciation	$15,229,320	$16,666,142	$18,189,781

C5 (R)

Citizens' Electric Company of Lewisburg
Rate Case with Fully Projected Future Test Year 2026 (R)

Operating Income Setting Forth the Operating Revenues and Expenses at Present Rates
HY 2024, FTY 2025 and FPFTY 2026
Answer to 52 Pa. Code 53.52 c[5]

	Account Title	Year Ended 12/31/2024 [Per Books]	Year Ended 12/31/2024 Distribution Only	Year Ended 12/31/2025 Distribution Only	Year Ended 12/31/2026 Distribution Only
1	Operating revenue	$16,378,412	$5,873,594	$6,145,655	$6,164,512
2					
3	Operating revenue deductions:				
4	Operating expenses	13,866,761	3,361,943	3,614,929	3,990,632
5	Depreciation expense	1,126,159	1,126,159	1,323,181	1,409,998
6	Taxes other than income tax	978,426	373,470	441,195	442,957
7	Rate case expense amortization	0	0	0	0
8	Total Operating revenue deductions	15,971,345	4,861,571	5,379,305	5,843,586
9					
10	Net operating income before income taxes	407,067	1,012,023	766,350	320,926
11					
12	Income tax expense	121,634	172,349	120,791	(10,537)
13					
14	Net utility operating income	$285,433	$839,675	$645,559	$331,463

C5-1 (R)

Citizens' Electric Company of Lewisburg
Rate Case with Fully Projected Future Test Year 2026 (R)

Comparison to Prior Rate Case
Prior Rate Case and FPFTY 2026

	Description	FPFTY 2026	R-2022-3032692, Order	Difference- Needs Higher (Lower) Revenue
1	Revenue	6,164,512	5,398,587	(765,925)
2				
3	*kWh*	*161,837,666*	*166,467,451*	
4				
5	O&M	3,990,632	2,613,736	1,376,896
6	Taxes other than income, Rate Case	442,957	497,242	(54,285)
7	Depreciation	1,409,998	1,029,328	380,670
8	Income tax	405,231	330,855	74,376
9				
10	Rate Base	$17,200,472	12,825,060	
11	Required Return	8.49%	7.23%	
12	Target Return	1,460,320	927,252	533,068
13				
14	Income Tax Expense			
15	Subtotal			1,544,800
16	Gross-Up for GRT			1.0627
17				1,641,657
18	Rounding difference			(185)
19	Revenue Increase Required at Recommended Return			1,641,472
20	Per Schedule C1 (R)			1,641,472

Citizens' Electric Company of Lewisburg
Rate Case with Fully Projected Future Test Year 2026 (R)
Summary of Allocator Values

	Units	Allocator Names	Total	Residential	Space Heating	GLP-1	GLP-3	Municipal Boulevard Lighting	Outdoor Lighting
		Class Allocators							
1	**InputAlloc**	**ALLOCATION VALUES**							
2	MWh	MWh-Meter	161,837,666	87,664,162	181,607	27,208,762	46,600,138	49,526	133,471
3	MW	NCP-Prim	100.00%	61.11%	0.16%	14.54%	23.96%	0.05%	0.18%
4	MW	NCP-Sec	100.00%	69.64%	0.19%	16.57%	13.35%	0.05%	0.20%
5	MW	NCP-Ltr	13,959	5,947	64	2,509	5,337	21	81
6	MW								
7	#	AVG-CUST	7,272	6,051	3	1,137	42	13	26
8	#	Services_Cost	6,753,684	5,612,820	2,656	1,078,485	46,616	13,107	
9	#	Meters	7,272	6,051	3	1,137	42	13	26
10	$	Meter_Cost	2,563,965	1,821,021	871	601,252	140,821		
11	$	Dist_Rev	6,055,143	3,903,746	8,741	1,092,138	909,143	26,151	115,224
12	$	CustDeposits	206,700	34,212	51	91,269	81,169		
13	$	Write-Offs	110,432	103,038	152	3,833	3,409		
14	$	StLgt-Cost	617,453					242,410	375,043
15									
16	**InputFunc**	**FUNCTIONAL ALLOCATORS**	**Total**				**Primary Dist**	**Secondary Dist**	**Billing**
17		OH_Cond	100.00%				75.37%	24.63%	
18		UG_Cond	100.00%				49.19%	50.81%	
19		Trans	100.00%				0.00%	100.00%	
20									
21									
22	**InputClass**	**CLASSIFICATIONS**	**Total**	**Demand**	**Commodity**	**Customer**			
23		PTF-Sec-Z	100.00%	19.31%		80.69%			
24		OH-Sec-Z	100.00%	22.60%		77.40%			
25		UG-Sec-Z	100.00%	42.89%		57.11%			
26		Trans-Min	100.00%	64.15%		35.85%			
27									

D1 (R)

Citizens' Electric Company of Lewisburg
Rate Case with Fully Projected Future Test Year 2026 (R)
Distribution System Functionalizaton and Classification

Primary / Secondary Split for OH ad UG Conductors

Line	Conductor Type	Circuit Miles	Line Miles (Circuit Miles X # of conductors)	Description
1	OH Primary (1 Ph)	87.71	175.79	1 phase wire, 1 neutral wire
2	OH Primary (2Ph)	4.84	14.53	2 phase wires, 1 neutral wire
3	OH Primary (3 Ph)	67.60	270.41	3 phase wires, 1 neutral wire
4	OH Secondary	82.70	82.70	1 triplexed conductor
5	UG Primary (1 Ph)	56.22	56.22	1 cable with concentric neutral
6	UG Primary (2 Ph)	0.39	0.98	2 cables with concentric neutral
7	UG Primary (3 Ph)	4.87	14.61	3 cables with concentric neutral
8	UG Secondary	68.63	68.63	1 multiplexed (UG SL, MBL)
9		372.96	683.86	
10				
11	**Totals**			
12	OH Primary	160.16	460.72	
13	OH Secondary	82.70	82.70	
14	OH Total	242.85	543.42	
15				
16	UG Primary	61.48	71.81	
17	UG Secondary	68.63	68.63	
18	UG Total	130.11	140.44	
19				
20	**Totals**			**Average**
21	OH Primary	65.95%	84.78%	75.37%
22	OH Secondary	34.05%	15.22%	24.63%
23	OH Total	100.00%	100.00%	100.00%
24				
25	UG Primary	47.25%	51.13%	49.19%
26	UG Secondary	52.75%	48.87%	50.81%
27	UG Total	100.00%	100.00%	100.00%
28				

D1 (R)

Citizens' Electric Company of Lewisburg

Rate Case with Fully Projected Future Test Year 2026 (R)

Distribution System Functionalizaton and Classification

	Zero-Load Components for Secondary		
Average %	**Poles**	**Overhead Conductors**	**Underground Conductors**
Zero-Load Component	**80.7%**	**77.4%**	**57.1%**
Material	21.4%	23.2%	41.6%
Total Cost	102.1%	100.6%	98.7%
	1,321,490	6,977,490	1,475,563

2025 Rate Case	**Poles**	**Overhead Conductors**	**Underground Conductors**
Labor	36.3%	32.4%	21.6%
Overhead	44.2%	37.6%	25.9%
Vehicle	8.5%	10.0%	4.4%
Zero-Load Component	**89.0%**	**79.9%**	**51.8%**
Material	11.0%	20.1%	48.2%
Total Cost	100.0%	100.0%	100.0%

2022 Rate Case	**Poles**	**Overhead Conductors**	**Underground Conductors**
Labor	35.4%	34.0%	20.0%
Overhead	38.4%	39.4%	21.6%
Vehicle	17.1%	9.1%	4.0%
Zero-Load Component	**90.8%**	**82.5%**	**45.6%**
Material	9.2%	17.5%	54.4%
Total Cost	100.0%	100.0%	100.0%

2019 Rate Case	**Poles**	**Overhead Conductors**	**Underground Conductors**
Labor	34.3%	30.6%	23.8%
Overhead	38.5%	33.0%	24.6%
Vehicle	11.9%	10.3%	3.8%
Zero-Load Component	**84.7%**	**73.9%**	**52.2%**
Material	15.3%	26.1%	47.8%
Total Cost	100.0%	100.0%	100.0%

2016 Rate Case	**Poles**	**Overhead Conductors**	**Underground Conductors**
Labor	36.9%	24.6%	40.0%
Overhead	14.9%	19.7%	5.3%
Vehicle	10.5%	30.9%	22.6%
Zero-Load Component	**62.3%**	**75.2%**	**67.9%**
Material	37.7%	24.8%	32.1%
Total Cost	100.0%	100.0%	100.0%

D1 (R)

Citizens' Electric Company of Lewisburg

Rate Case with Fully Projected Future Test Year 2026 (R)

Distribution System Functionalizaton and Classification

	2010 Rate Case	Poles	Overhead Conductors	Underground Conductors
68				
69	Labor	27.7%	30.8%	25.3%
70	Overhead	32.3%	32.3%	32.3%
71	Vehicle	16.7%	12.4%	10.5%
72	**Zero-Load Component**	**76.7%**	**75.5%**	**68.1%**
73	Material	23.3%	24.5%	31.9%
74	Total Cost	100.0%	100.0%	100.0%

Citizens' Electric Company of Lewisburg
Rate Case with Fully Projected Future Test Year 2026 (R)

CLASS NON-COINCIDENT PEAK (NCP) DEMANDS

Line	Description	Residential	Space Heating	GLP-1	GLP-3	Municipal Boulevard Lighting	Outdoor Lighting	Total
1	**NCP- Primary**							
2	NCP-2015	29,388	404	6,654	15,238	27	108	51,820
3	NCP-2018	26,775	245	6,364	10,303	28	70	43,785
4	NCP-2019	28,933	386	6,726	10,054	25	70	46,194
5	NCP-2020	22,573	248	5,235	8,973	21	70	37,120
6	NCP-2021	22,969	245	6,364	10,303	28	70	39,979
7	NCP-2022	29,102	386	6,726	10,054	25	70	46,363
8	NCP-2023	23,679	248	5,235	8,973	21	70	38,227
9	NCP-2024	25,788	67	6,374	8,579	19	82	40,909
10								
11	NCP shares- 2015	56.71%	0.78%	12.84%	29.41%	0.05%	0.21%	100.00%
12	NCP shares- 2018	61.15%	0.56%	14.53%	23.53%	0.06%	0.16%	100.00%
13	NCP shares- 2019	62.63%	0.84%	14.56%	21.76%	0.05%	0.15%	100.00%
14	NCP shares- 2020	60.81%	0.67%	14.10%	24.17%	0.06%	0.19%	100.00%
15	NCP shares- 2021	57.45%	0.61%	15.92%	25.77%	0.07%	0.18%	100.00%
16	NCP shares- 2022	62.77%	0.83%	14.51%	21.69%	0.05%	0.15%	100.00%
17	NCP shares- 2023	61.94%	0.65%	13.69%	23.47%	0.06%	0.18%	100.00%
18	NCP shares- 2024	63.04%	0.16%	15.58%	20.97%	0.05%	0.20%	100.00%
19	**NCP Primary- SimpleAverage**	**60.81%**	**0.64%**	**14.47%**	**23.85%**	**0.06%**	**0.18%**	**100.00%**
20	**NCP Primary- Adjusted Aver**	**61.11%**	**0.16%**	**14.54%**	**23.96%**	**0.05%**	**0.18%**	**100.00%**
21					% Primary			
22	**NCP- Secondary**				**51.11%**			
23	Shares of Class peaks	61.11%	0.16%	14.54%	11.71%	0.05%	0.18%	87.75%
24	**Shares of Total**	**69.64%**	**0.19%**	**16.57%**	**13.35%**	**0.05%**	**0.20%**	**100.00%**
25								
26	**NCP-LTr**							
27	Secondary Class peaks	27,842	75	6,623	5,337	21	81	39,979
28	(line 23 X line 6 total)							
29	Capacity of Minimum system	21,895	11	4,114	-	-	-	26,020
30	Class peaks less Capacity of minimum system	5,947	64	2,509	5,337	21	81	13,959
31	**Shares of Total**	**42.60%**	**0.46%**	**17.98%**	**38.23%**	**0.15%**	**0.58%**	**100.00%**
32								
33	Total number of transformers on system							2,602
34	Transfomer capacity- kVa							12.5
35	Assumed power factor							80%
36	Total Capacity of Transformer minimum system							26,020
37	Number of customers on Mimin	6,051	3	1,137				7,191
38	Capacity per Customer of Transformer minimum system- kW							3.62

D3 (R)

Citizens' Electric Company of Lewisburg
Rate Case with Fully Projected Future Test Year 2026 (R)
Transformers Classification

Transformers Minimum Size Component

	Transformers	Minimum Size	Cost for Minimum Size	Number	Total Cost Minimum Size	Replacement Cost	Minimum Size Component
1	Line	TPD50 X 1/4	$911	1,933	1,760,151	3,587,483	49.1%
2	Pad-Mount	TPD50 X 1/4	$911	669	609,178	2,858,370	21.3%
3				2,602	2,369,329	6,445,853	**36.8%**
4							

Transformers Unit Costs

	Part #	Description	Total Cost	Count	Extended
7	TPM15	Transformer, 15KVA, Pole	$1,164	703	$817,963
8	TPM25	Transformer, 25KVA, Pole	$1,740	602	1,047,198
9	TPM50	Transformer, 50KVA, Pole	$2,385	499	1,189,882
10	TPM100	Transformer, 100KVA, Pole	$4,040	115	464,546
11	TPM167/480	Transformer, 167KVA/480, Pole	$4,850	14	67,893
12				1,933	3,587,483
13					
14	TPD25	Transformer, 25KVA, Pad	$2,964	247	732,187
15	TPD50	Transformer, 50KVA, Pad	$3,642	351	1,278,454
16	TPD50 X 1/4	Transformer, 50KVA, Pad X 1/4	$911		
17	TPD100	Transformer, 100KVA, Pad	$4,822	35	168,781
18	TPD150/208	Transformer, 150KVA/208, Pad	$12,422	9	111,801
19	TPD300	Transformer, 300KVA,Pad	$16,622	10	166,223
20	TPD500/480	Transformer, 500KVA/480, Pad	$17,289	8	138,315
21	TPD1000/480	Transformer, 1000KVA/480, Pad	$28,734	8	229,875
22	TPD1500/480	Transformer, 1500KVA/480, Pad	$32,734	1	32,734
23				669	2,858,370
24				2,602	6,445,853
25					
26	Total				6,445,853
27	Average				$2,477
28	Minimum Component- 2025				36.8%

D4 (R)

Citizens' Electric Company of Lewisburg
Rate Case with Fully Projected Future Test Year 2026 (R)
Service Costs

Line	Rate Class	Type	Replacement Cost	Services	Services Cost
1	Residential Overhead	Sec-OH-1Ph	$840	3,404	2,860,177
2	Residential Overhead	Sec-OH-3Ph	$976	17	16,587
3	Residential Underground	Sec-UG-1Ph	$1,039	2,420	2,513,751
4	Residential Underground	Sec-UG-3Ph	$1,185	107	126,764
5	Residential Total			5,948	5,517,278
6	**Residential in FPFTY**	**Average**	**$928**	**6,051**	**5,612,820**
7					
8	SH Overhead	Sec-OH-1Ph	$840	2	1,680
9	SH Overhead	Sec-OH-3Ph	$976	1	976
10	SH Underground	Sec-UG-1Ph	$1,039	0	0
11	SH Underground	Sec-UG-3Ph	$1,185	0	0
12	SH Total	Average		3	2,656
13	**SH in FPFTY**		**$885**	**3**	**2,656**
14					
15	GLP1 Overhead	Sec-OH-1Ph	$840	583	489,860
16	GLP1 Overhead	Sec-OH-3Ph	$976	103	100,495
17	GLP1 Underground	Sec-UG-1Ph	$1,039	305	316,816
18	GLP1 Underground	Sec-UG-3Ph	$1,185	139	164,675
19	GLP1 Total	Average		1,130	1,071,845
20	**GLP1 in FPFTY**		**$949**	**1,137**	**1,078,485**
21					
22	GLP3 Overhead	Sec-OH-1Ph	$840	5	4,201
23	GLP3 Overhead	Sec-OH-3Ph	$976	5	4,878
24	GLP3 Underground	Sec-UG-1Ph	$1,039	0	0
25	GLP3 Underground	Sec-UG-3Ph	$1,185	27	31,987
26	GLP3 Total	Average		37	41,067
27	**GLP3 in FPFTY**		**$1,110**	**42**	**46,616**
28					
29	MBL Overhead	Sec-OH-1Ph	$840	2	1,680
30	MBL Overhead	Sec-OH-3Ph	$976	0	0
31	MBL Underground	Sec-UG-1Ph	$1,039	11	11,426
32	MBL Underground	Sec-UG-3Ph	$1,185	0	0
33	MBL Total	Average		13	13,107
34	**MBL in FPFTY**		**$1,008**	**13**	**13,107**
35	**Total Service Cost**			**7,246**	**6,753,684**

D5 (R)

Citizens' Electric Company of Lewisburg
Rate Case with Fully Projected Future Test Year 2026 (R)
Meter Costs

Line	Meter Types	Description	Total Cost Per Meter	Number Installed RS	SH	GLP1	GLP3	MBL	Total	Material	Labor / OH	Truck
1	M2S200T	Meter 2s, Cl 200, 240V, 1 Ph	$ 290.33	5,540	2	797		13	6,352	$ 227.00	$ 47.99	$ 15.34
2	M2S200T-RD	Meter 2s, Cl 200, 240V, 1 Ph	$ 368.33	25		5			30	$ 305.00	$ 47.99	$ 15.34
3	M2S320T	Meter 2s, Cl 320, 240V, 1 Ph	$ 408.33	307		70			377	$ 345.00	$ 47.99	$ 15.34
4	M3S20T	Meter, 3S Cl 20, 240V, 1 Ph	$ 408.33	8		8			16	$ 345.00	$ 47.99	$ 15.34
5	M4S20T	Meter, 4S Cl 20, 240V, 1 Ph	$ 408.33	9		19			28	$ 345.00	$ 47.99	$ 15.34
6	M8/9S20T	Meter 8S/9S, Cl 20, AXS4E	$ 795.33	2		120	39		161	$ 732.00	$ 47.99	$ 15.34
7	M12S200T	Meter, Form 12S Class 200	$ 408.33	107		16			123	$ 345.00	$ 47.99	$ 15.34
8	M15/16S20T	Meter, Form 15S/16S Class 20	$ 795.33	1		96			97	$ 732.00	$ 47.99	$ 15.34
9												
10	CT600/5	C.T., Ratio 600:5 (600V)	$ 292.66	32		403	75		510	$ 229.33	$ 47.99	$ 15.34
11	CT1200/5	C.T., Ratio 1200:5 (600V)	$ 253.27				24		24	$ 189.94	$ 47.99	$ 15.34
12	CT2000/5	C.T., Ratio 2000:5 (600V)	$ 253.27				3		3	$ 189.94	$ 47.99	$ 15.34
13	CTHV200/5	C.T., Ratio 200:5 (7200V)	$ 1,497.33				12		12	$1,434.00	$ 47.99	$ 15.34
14	CTHV1000/5	C.T., Ratio 1000:5 (7200V)	$ 1,593.33				3		3	$1,530.00	$ 47.99	$ 15.34
15												
16	PTHV	P.T., H.V. (7200), RATIO 60:1	$ 1,765.33				15		15	$1,702.00	$ 47.99	$ 15.34
17	PT2.4	P.T., L.V. (600), RATIO 2.4:1	$ 402.39			72	54		126	$ 339.06	$ 47.99	$ 15.34
18	PT2.5	P.T., L.V. (600), RATIO 2.5:1	$ 402.39						0	$ 339.06	$ 47.99	$ 15.34
19	VTPack2.4 1.1.1	VTpack 2.4 1.1.1	$ 1,207.16						0	$1,017.18	$ 143.97	$ 46.01
20												
21	**Total Cost**		2,538,568	1,805,371	581	598,080	130,762	3,774		2025 Average Crew Rate:/ ho		
22	Customers above		7,184	5,999	2	1,131	39	13		With Adder For OH		######
23	Average per Customer		353.36	300.95	290.33	528.81	3,352.88	290.33		2025 Truck Rate:/ hour		
24	Customers in Future Year 2023		7,246	6,051	3	1,137	42	13				
25	**Meter Cost for Class**			**1,821,021**	**871**	**601,252**	**140,821**	**3,774**	**2,567,739**			

D6 (R)

Citizens' Electric Company of Lewisburg
Rate Case with Fully Projected Future Test Year 2026 (R)
Customer Deposits and Advances; Uncollectible Accounts

Line	Class	Revenue	Deposits	Net Write-offs
1	Residential	2,870,229	34,212	103,038
2	Space Heating	4,244	51	152
3	GLP-1	997,912	91,269	3,833
4	GLP-3	887,487	81,169	3,409
5		4,759,872	206,700	110,432
6				
7	Residential / Res plus SH)	99.9%		
8	GLP1 / GLP1 plus GLP3)	52.9%		
9				

10		Residential- Net	Non-Residential- Net	Total
11	2024	24,287	645	24,932
12	2023	20,270	0	20,270
13	2022	16,138	2,291	18,429
14	2021	25,496	(6,726)	18,770
15	2020	16,999	11,032	28,030
16		103,191	7,241	110,432
17		93.4%	6.6%	100.0%
18				

19	**Deposits**	
20	Residential	34,263
21	Non-residential	172,438
22		206,700
23		

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Index
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Citizens Electric Company of Lewisburg
Embedded Cost of Service Study (ECOSS) (R)
FPFTY Ending December 31, 2026
Index to Class Cost of Service Study

Line	SCHEDULE	DESCRIPTION
1	E (R)	Index to Class Cost of Service Study
2	E-1 (R)	Summary of Results
3	E-1A (R)	Class Allocations- Total
4	E-1B (R)	Revenue Requirement By Functional Classification
5	E-1C (R)	Customer-Related Costs In Revenue Requirement
6	E-2 (R)	Funtionalization
7	E-3 (R)	Classification
8	E-4A (R)	Class Allocation- Primary Demand
9	E-4B (R)	Class Allocation- Secondary Demand
10	E-4C (R)	Class Allocation- Secondary Customer
11	E-4D (R)	Class Allocation- Billing Customer
12	E-5A (R)	Allocator Assignments
13	E-5B (R)	Functionalization Factors
14	E-5C (R)	Classification Factors
15	E-5D (R)	Class Allocation Factors

Sum
Summary of Results
Tot
E-1 (R)

Citizens Electric Company of Lewisburg
Embedded Cost of Service Study (ECOSS) (R)
FPFTY Ending December 31, 2026
Summary of Results

Line	Account	No.	Balance	RS	SH	GLP-1	GLP-3	MBL	OL
1	Distribution Revenue		6,055,143	3,903,746	8,741	1,092,138	909,143	26,151	115,224
2	Forfeited Discounts		35,091	22,623	51	6,329	5,269	152	668
3	Other Revenue	302	74,278	48,754	105	11,479	13,439	104	397
4	**Total Revenue**	303	6,164,512	3,975,123	8,897	1,109,947	927,850	26,407	116,289
5									
6	Expenses		5,833,058	3,942,466	7,374	902,209	832,175	54,750	94,084
7	Net income		331,455	32,657	1,523	207,738	95,676	(28,343)	22,204
8									
9	Rate Base		17,199,344	11,466,975	21,100	2,616,738	2,367,878	282,654	443,999
10									
11	Return on Rate Base		1.93%	0.28%	7.22%	7.94%	4.04%	(10.03%)	5.00%
12	Relative		*1.00*	*0.15*	*3.75*	*4.12*	*2.10*	*(5.20)*	*2.60*
13	Revenue Requirement		7,805,858	5,269,729	9,726	1,192,309	1,100,832	89,222	144,040
14									
15	Operating expenses		3,896,694	2,682,511	4,632	594,326	535,521	29,868	49,835
16	Depreciation expense		1,409,998	918,048	2,007	216,554	219,018	21,005	33,364
17	Regulatory Commission Expenses		63,038	42,028	77	9,591	8,679	1,036	1,627
18	General taxes / Other		85,704	56,879	110	13,102	12,291	1,289	2,033
19	Uncollectibles expense		30,900	19,921	45	5,573	4,639	133	588
20	GRT		454,093	306,639	565	69,353	63,865	5,234	8,436
21			5,940,426	4,026,027	7,437	908,499	844,013	58,566	95,884
22	Pre-tax income		1,865,432	1,243,702	2,289	283,810	256,819	30,657	48,156
23	Income taxes		405,208	270,156	497	61,649	55,786	6,659	10,460
24	Net income		1,460,224	973,546	1,791	222,161	201,033	23,997	37,696
25									
26	Return on Rate Base		8.49%	8.49%	8.49%	8.49%	8.49%	8.49%	8.49%
27									
28	Revenue Increase Required		1,641,345	1,294,606	829	82,363	172,981	62,816	27,751
29	Revenue Increase %		27.11%	33.16%	9.48%	7.54%	19.03%	240.21%	24.08%

Total
Class Allocations- Total
Tot
E-1A (R)

Citizens Electric Company of Lewisburg
Embedded Cost of Service Study (ECOSS) (R)
FPFTY Ending December 31, 2026
Class Allocations- Total

Line	Account	No.	Balance	Check	RS	SH	GLP-1	GLP-3	MBL	OL
1	**I. ELECTRIC PLANT IN SERVICE**									
2	INTANGIBLE PLANT									
3	Organization	302	0	.	0	0	0	0	0	0
4	EDI Software	303	0	.	0	0	0	0	0	0
5	Total INTANGIBLE Plant		0	.	0	0	0	0	0	0
6										
7	**C. TRANSMISSION PLANT**									
8	Transmission Plant	361	0	.	0	0	0	0	0	0
9	Total TRANSMISSION Plant	350-359	0	.	0	0	0	0	0	0
10										
11	**D. DISTRIBUTION PLANT**									
12	Land and Land Rights	360	21,453	.	13,110	35	3,119	5,141	10	38
13	Station Equipment	362	776,412	.	474,468	1,277	112,873	186,053	358	1,383
14	Poles, Towers and Fixtures	364	4,934,235	.	3,252,103	6,960	732,855	928,114	3,593	10,610
15	OH Conductors and Devices	365	9,866,317	.	6,491,927	14,035	1,466,136	1,866,043	7,084	21,091
16	UG Conduits and Conductors	366	4,063,329	.	2,819,190	5,433	621,625	604,009	3,496	9,575
17	Line Transformers	368	3,430,881	.	1,461,574	15,748	616,716	1,311,723	5,168	19,953
18	Services	369	4,949,542	.	4,113,442	1,947	790,384	34,164	9,605	0
19	Meters	370	1,798,757	.	1,277,542	611	421,810	98,793	0	0
20	Street Lighting	373	820,118	.	0	0	0	0	321,975	498,143
21	Total DISTRIBUTION Plant	360-373	30,661,045	.	19,903,356	46,047	4,765,519	5,034,040	351,290	560,794
22										
23	**E. GENERAL PLANT**									
24	General Plant	389	4,280,032	.	2,973,006	4,823	649,360	547,406	39,793	65,644
25	Communication Equip	398	428,037	.	297,324	482	64,941	54,745	3,980	6,565
26	Total GENERAL Plant	389-399	4,708,069	.	3,270,330	5,305	714,301	602,150	43,772	72,209
27										
28	**TOTAL UTILITY PLANT**		35,369,114	.	23,173,687	51,352	5,479,820	5,636,190	395,062	633,003
29										

Total
Class Allocations- Total
Tot
E-1A (R)

Citizens Electric Company of Lewisburg
Embedded Cost of Service Study (ECOSS) (R)
FPFTY Ending December 31, 2026
Class Allocations- Total

Line	Account	No.	Balance	Check	RS	SH	GLP-1	GLP-3	MBL	OL
30	**II. DEPRECIATION RESERVE**									
31	Intangible Plant	108.3	0	.	0	0	0	0	0	0
32	Transmission Plant	108.5	0	.	0	0	0	0	0	0
33	Station Equipment	108.5	763,782	.	466,749	1,256	111,037	183,026	352	1,361
34	Poles, Towers and Fixtures	108.6	3,612,745	.	2,381,123	5,096	536,582	679,546	2,631	7,768
35	OH Conductors and Devices	108.6	2,888,827	.	1,900,816	4,109	429,280	546,372	2,074	6,175
36	UG Conduits and Conductors	108.6	2,587,766	.	1,795,426	3,460	395,887	384,668	2,226	6,098
37	Line Transformers	108.6	2,598,828	.	1,107,115	11,929	467,150	993,605	3,915	15,114
38	Services	108.6	2,261,922	.	1,879,827	890	361,203	15,613	4,390	0
39	Meters	108.6	102,702	.	72,943	35	24,084	5,641	0	0
40	Street Lighting	108.6	170,989	.	0	0	0	0	67,129	103,859
41	General Plant	108.6	3,202,220	.	2,224,334	3,609	485,836	409,556	29,772	49,113
35	Total DEPRECIATION RESERVE	108	18,189,781	.	11,828,333	30,384	2,811,059	3,218,027	112,489	189,489
42										
43	**III. OTHER RATE BASE ITEMS**									
44	Cash Working Capital	131	481,732	.	331,300	574	73,575	66,254	3,747	6,283
45	CWIP	131	0	.	0	0	0	0	0	0
45	Materials & Supplies	255	328,809	.	226,130	392	50,219	45,222	2,557	4,289
46	Customer Deposits		(189,068)	.	(31,294)	(46)	(83,483)	(74,245)	0	0
47	ADIT / EDIT	154	(336,658)	.	(220,577)	(489)	(52,159)	(53,648)	(3,760)	(6,025)
48	Accrued Pension / OPEB	182	(264,804)	.	(183,939)	(298)	(40,176)	(33,868)	(2,462)	(4,061)
49	Total OTHER RATE BASE ITEMS	131-283	20,011	.	121,621	132	(52,024)	(50,285)	82	485
50										
51	**TOTAL RATE BASE**		17,199,344	.	11,466,975	21,100	2,616,738	2,367,878	282,654	443,999
52										

Total
Class Allocations- Total
Tot
E-1A (R)

Citizens Electric Company of Lewisburg
Embedded Cost of Service Study (ECOSS) (R)
FPFTY Ending December 31, 2026
Class Allocations- Total

Line	Account	No.	Balance	Check	RS	SH	GLP-1	GLP-3	MBL	OL
53	**I. OPERATING AND MAINTENANCE EXPENSES**									
54	**B. TRANSMISSION EXPENSE**									
55	Transmission Expense		0	.	0	0	0	0	0	0
56	Total TRANSMISSION Expense		0		0	0	0	0	0	0
57										
58	**C. DISTRIBUTION OPER. & MAINT. E**									
59	Ops Supv & Engineering	580	154,958	.	101,051	206	23,608	25,521	1,736	2,836
60	Station Expenses	582	14,046	.	8,584	23	2,042	3,366	6	25
61	OH Line Expenses	583	242,072	.	159,281	344	35,972	45,784	174	517
62	Street Lighting Expenses	585	5,137	.	0	0	0	0	2,017	3,120
63	Meter Expenses	586	50,712	.	36,018	17	11,892	2,785	0	0
64	Customer Installation Expenses	587	56,416	.	46,944	23	8,821	326	101	202
65	Misc. Distribution Expenses	588	495,254	.	332,183	730	75,281	85,633	355	1,072
66	Rents	589	525	.	370	1	82	71	0	1
67	Maint Supv & Engineering	590	0	.	0	0	0	0	0	0
68	Maint of Station Equip	592	17,209	.	10,517	28	2,502	4,124	8	31
69	Maint of OH Lines	593	826,836	.	544,049	1,176	122,868	156,382	594	1,768
70	Maint of UG Lines	594	14,827	.	10,287	20	2,268	2,204	13	35
71	Maint of Line Transformers	595	27,468	.	11,701	126	4,937	10,502	41	160
72	Maint of Lighting	596	24,187	.	0	0	0	0	9,496	14,691
73	Maint of Misc. Plant	599	0	.	0	0	0	0	0	0
74	Total DISTR. OPER. & MAINT. EXP.	500-599	1,929,647	.	1,260,983	2,695	290,273	336,697	14,541	24,458
75	Distribution Expense		1,929,647		1,260,983	2,695	290,273	336,697	14,541	24,458
76	**D. CUSTOMER ACCOUNTS AND SERVICE**									
77	Supervision	901	0	.	0	0	0	0	0	0
78	Meter Reading Exp	902	26,000	.	18,466	9	6,097	1,428	0	0
79	Customer Records & Coll	903	492,479	.	409,789	203	77,001	2,844	880	1,761
80	Uncollectible Accounts	904	30,900	.	19,921	45	5,573	4,639	133	588
81	Subtotal - Customer Accounts Exp.	901-905	549,379	.	448,177	257	88,671	8,912	1,014	2,349
82	Total CUST. ACCT. & SERV. EXP.	901-919	549,379	.	448,177	257	88,671	8,912	1,014	2,349
83										

Total
Class Allocations- Total
Tot
E-1A (R)

Citizens Electric Company of Lewisburg
Embedded Cost of Service Study (ECOSS) (R)
FPFTY Ending December 31, 2026
Class Allocations- Total

Line	Account	No.	Balance	Check	RS	SH	GLP-1	GLP-3	MBL	OL
84	**E. ADMINISTRATIVE AND GENERAL**									
85	Administrative & General Salaries	920	884,948	.	614,705	997	134,263	113,183	8,228	13,573
86	Office Supplies & Expenses	921	151,265	.	105,072	170	22,950	19,346	1,406	2,320
87	Outside Services Employed	923	38,110	.	25,582	48	5,907	5,468	421	683
88	Property Insurance	924	11,059	.	7,246	16	1,713	1,762	124	198
89	Injuries and Damages	925	28,907	.	18,940	42	4,479	4,606	323	517
90	Employee Pensions & Benefits	926	8,755	.	6,081	10	1,328	1,120	81	134
91	Regulatory Commission Expense	928	108,889	.	72,597	134	16,567	14,991	1,789	2,811
92	Miscellaneous General Expense	930	114,218	.	76,672	145	17,704	16,388	1,262	2,046
89	Maint General Property	932	165,455	.	108,406	240	25,634	26,366	1,848	2,961
93	Total A&G Expense	920-932	1,511,606	.	1,035,301	1,803	230,546	203,231	15,483	25,243
94										
95	TOTAL OPERATING EXPENSES		3,990,632	.	2,744,460	4,754	609,490	548,839	31,037	52,050
96										
97	**II. DEPRECIATION EXPENSE**									
98	Intangible Plant		0	.	0	0	0	0	0	0
99	Station Equipment	361/362	4,197	.	2,565	7	610	1,006	2	7
100	Poles, Towers and Fixtures	364	196,900	.	129,775	278	29,244	37,036	143	423
101	OH Conductors and Devices	364	380,183	.	250,156	541	56,495	71,905	273	813
102	UG Conduits and Conductors	364	158,473	.	109,951	212	24,244	23,557	136	373
103	Line Transformers	364	133,449	.	56,850	613	23,988	51,021	201	776
104	Services	364	191,856	.	159,447	75	30,637	1,324	372	0
105	Meters	364	70,794	.	50,280	24	16,601	3,888	0	0
106	Street Lighting	364	45,208	.	0	0	0	0	17,749	27,460
107	General Plant	364	228,938	.	159,025	258	34,734	29,281	2,128	3,511
108	Total DEPRECIATION Expense	403	1,409,998	.	918,048	2,007	216,554	219,018	21,005	33,364
109										
110	**III. TAXES and OTHER**									
111	**A. GENERAL TAXES**									
112	Payroll related	408	0	.	0	0	0	0	0	0
113	PURTA, Real estate	408.16	15,062	.	9,869	22	2,334	2,400	168	270
114	PUC Assessment		63,038	.	42,028	77	9,591	8,679	1,036	1,627
115	PA Use Tax	408	7,604	.	4,982	11	1,178	1,212	85	136
116	Subtotal - General Taxes		85,704	.	56,879	110	13,102	12,291	1,289	2,033
117										
118	**B. GROSS RECEIPTS TAX**									
119	Gross Receipts tax		357,253	.	230,321	516	64,436	53,639	1,543	6,798
120	Subtotal- Gross Receipts tax		357,253	.	230,321	516	64,436	53,639	1,543	6,798
121										

Total
Class Allocations- Total
Tot
E-1A (R)

Citizens Electric Company of Lewisburg
Embedded Cost of Service Study (ECOSS) (R)
FPFTY Ending December 31, 2026
Class Allocations- Total

Line	Account	No.	Balance	Check	RS	SH	GLP-1	GLP-3	MBL	OL
122	**B. FEDERAL / STATE INCOME TAXES**									
123	State Income Tax Expense		(11,138)	.	(7,298)	(16)	(1,726)	(1,775)	(124)	(199)
124	Federal Income Tax Expense		609	.	55	3	352	162	0	38
125	Subtotal - Federal / State Income Taxes	409-411	(10,529)	.	(7,242)	(14)	(1,374)	(1,613)	(124)	(162)
126	Total TAXES	408-411	432,429	.	279,957	612	76,165	64,317	2,708	8,669
127										
128	**TOTAL EXPENSES**		5,833,058	.	3,942,466	7,374	902,209	832,175	54,750	94,084
129										
130	**IV. OPERATING REVENUES at Present Rates**									
131	Distribution Revenue		6,055,143	.	3,903,746	8,741	1,092,138	909,143	26,151	115,224
132	Forfeited Discounts		35,091	.	22,623	51	6,329	5,269	152	668
133	Rent For Electric Property		60,240	.	39,704	85	8,947	11,331	44	130
134	Other Electric Revenues		14,038	.	9,050	20	2,532	2,108	61	267
135	Total REVENUES		6,164,512	.	3,975,123	8,897	1,109,947	927,850	26,407	116,289
136										
137	TOTAL EXPENSES		5,833,058	.	3,942,466	7,374	902,209	832,175	54,750	94,084
138	**V. NET INCOME at Present Rates**		331,455	.	32,657	1,523	207,738	95,676	(28,343)	22,204
139										
140	**SUMMARY REPORT**									
141	OPERATING REVENUES									
142	Utility Revenues	440-446	6,090,234	.	3,926,369	8,792	1,098,467	914,412	26,302	115,892
143	Other Operating Revenues	450-456	74,278	.	48,754	105	11,479	13,439	104	397
144	Total Operating Revenues		6,164,512	.	3,975,123	8,897	1,109,947	927,850	26,407	116,289
145										
146	OPERATING EXPENSES									
147	Distribution / Transmission	580-599	1,929,647	.	1,260,983	2,695	290,273	336,697	14,541	24,458
148	Customer Acctg & Service	901-919	549,379	.	448,177	257	88,671	8,912	1,014	2,349
149	Admin & General	920-932	1,511,606	.	1,035,301	1,803	230,546	203,231	15,483	25,243
150	Total Operating Expenses		3,990,632	.	2,744,460	4,754	609,490	548,839	31,037	52,050
151										
152	Depreciation Expense	403	1,409,998	.	918,048	2,007	216,554	219,018	21,005	33,364
153	Taxes Other Than Income Tax / Other	408	442,957	.	287,200	626	77,539	65,930	2,832	8,831
154	INCOME BEFORE INCOME TAXES		320,926	.	25,415	1,509	206,364	94,063	(28,468)	22,043
155	Income Taxes	409-411	(10,529)	.	(7,242)	(14)	(1,374)	(1,613)	(124)	(162)
156	**NET INCOME**		331,455	.	32,657	1,523	207,738	95,676	(28,343)	22,204
157										
158	**RATE BASE**		17,199,344	.	11,466,975	21,100	2,616,738	2,367,878	282,654	443,999
159	Return on Rate Base		1.93%							
160										

Total
Class Allocations- Total
Tot
E-1A (R)

Citizens Electric Company of Lewisburg
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FPFTY Ending December 31, 2026
Class Allocations- Total

Line	Account	No.	Balance	Check	RS	SH	GLP-1	GLP-3	MBL	OL
161	**REVENUE REQUIREMENTS**									
162	Target Rate of Return		8.4900%		8.4900%	8.4900%	8.4900%	8.4900%	8.4900%	8.4900%
163										
164	Rate Base		17,199,344	.	11,466,975	21,100	2,616,738	2,367,878	282,654	443,999
165										
166	Operating expenses		3,896,694	.	2,682,511	4,632	594,326	535,521	29,868	49,835
167	Uncollectibles expense		30,900	.	19,921	45	5,573	4,639	133	588
168	Depreciation expense		1,409,998	.	918,048	2,007	216,554	219,018	21,005	33,364
169	Regulatory Commission Expenses		63,038	.	42,028	77	9,591	8,679	1,036	1,627
170	General taxes / Other		85,704	.	56,879	110	13,102	12,291	1,289	2,033
171	Subtotal- Operating Costs to recover		5,486,333	.	3,719,387	6,872	839,146	780,148	53,332	87,448
172										
173	Target Return on Rate Base- After taxes		1,460,224		973,546	1,791	222,161	201,033	23,997	37,696
174										
175	Income taxes to recover		405,208	.	270,156	497	61,649	55,786	6,659	10,460
176										
177	Subtotal- Rev Req before GRT		7,351,765	.	4,963,089	9,161	1,122,956	1,036,967	83,988	135,603
178	GRT needed		454,093	.	306,639	565	69,353	63,865	5,234	8,436
179	**TOTAL REVENUE REQUIREMENT**		7,805,858	.	5,269,729	9,726	1,192,309	1,100,832	89,222	144,040
180										
181	Revenue at Present rates		6,164,512		3,975,123	8,897	1,109,947	927,850	26,407	116,289
182	Revenue Excess (Deficiency)		(1,641,345)		(1,294,606)	(829)	(82,363)	(172,981)	(62,816)	(27,751)

FuncClass
Revenue
Tot
E-1B (R)

Citizens Electric Company of Lewisburg
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Revenue Requirement By Functional Classification

	Account Description	Total Dollars	RS	SH	GLP-1	GLP-3	MBL	OL
1	**Demand-related**							
2	Primary	3,574,284	2,185,931	5,866	519,812	853,450	2,133	7,092
3	Secondary	825,064	486,813	2,422	141,157	190,754	858	3,060
4		4,399,347	2,672,744	8,287	660,969	1,044,203	2,992	10,152
5	NCP-Primary	1	1	0	0	0	0	0
6	Per kW / month-Demand	$366,616.04	$364,473.68	$419,921.36	$378,884.53	$363,132.04	$540,175.91	$474,785.06
7								
8	kWh-Meter	161,837,666	87,664,162	181,607	27,208,762	46,600,138	49,526	133,471
9	Per kWh-Meter	$0.02718	$0.03049	$0.04563	$0.02429	$0.02241	$0.06040	$0.07606
10								
11	**Customer-related**							
12	Secondary	1,751,702	1,286,236	647	244,200	12,401	82,082	126,137
13	Billing	1,654,808	1,310,750	792	287,139	44,228	4,148	7,751
14		3,406,510	2,596,985	1,438	531,340	56,629	86,231	133,888
15	Number of Bills	87,264	72,612	36	13,644	504	156	312
16	Per bill	$39.04	$35.77	$39.95	$38.94	$112.36	$552.76	$429.13
17								
18	Total revenue requirement	7,805,858	5,269,729	9,726	1,192,309	1,100,832	89,222	144,040
	Secondary Per kW / month-Demand	$68,756.02	$66,385.17	$122,700.32	$80,914.78	$66,336.50	$154,994.98	$143,109.94

Customer
Custome
Tot
E-1C (R)

Citizens Electric Company of Lewisburg
Embedded Cost of Service Study (ECOSS) (R)
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Customer-Related Costs In Revenue Requirement

	Account Description	FERC	Total Dollars	RS	SH	GLP-1	GLP-3	MBL	OL
1	Services, cost	Acct 369	4,949,542	4,113,442	1,947	790,384	34,164	9,605	0
2	Services, Acc Depr	Portion Acct 108	(2,261,922)	(1,879,827)	(890)	(361,203)	(15,613)	(4,390)	0
3	Meters, cost	Acct 370	1,798,757	1,277,542	611	421,810	98,793	0	0
4	Meters, Acc Depr	Portion Acct 108	(102,702)	(72,943)	(35)	(24,084)	(5,641)	0	0
5	Transformers, cost	Acct 368	3,430,881	1,461,574	15,748	616,716	1,311,723	5,168	19,953
6	Transformers, Acc Depr	Portion Acct 108	(2,598,828)	(1,107,115)	(11,929)	(467,150)	(993,605)	(3,915)	(15,114)
7	ADIT	Portion Acct 154	(74,560)	(59,745)	(27)	(13,268)	(1,417)	(103)	0
8	Service / Meter/ Trnsf Rate Base		5,141,169	3,732,928	5,425	963,206	428,404	6,366	4,839
9	Rate of return on rate base		8.49%	8.49%	8.49%	8.49%	8.49%	8.49%	8.49%
10	Return on Service / Meter rate base		436,485	316,926	461	81,776	36,372	540	411
11	Income tax gross-up		121,123	87,946	128	22,693	10,093	150	114
12	GRT gross-up		34,440	25,015	36	6,452	2,862	43	33
13	Customer-charge return component		592,049	429,886	625	110,921	49,326	734	557
14									
15	Meter expenses	Acct 586	50,712	36,018	17	11,892	2,785	0	0
16	Customer installatins expense	Acct 587	56,416	46,944	23	8,821	326	101	202
17	Meter reading expenses	Acct 902	26,000	18,466	9	6,097	1,428	0	0
18	Customer records and collection	Acct 903	492,479	409,789	203	77,001	2,844	880	1,761
19	Service / Meter / EDI depreciation exp	Portion Acct 403	262,650	209,727	100	47,238	5,212	372	0
20	Labor-related		174,841	143,009	67	28,697	1,884	402	781
21	Customer-charge expense component		1,063,098	863,953	419	179,746	14,480	1,756	2,743
22									
23	Customer-charge expense component		1,655,146	1,293,839	1,043	290,667	63,806	2,490	3,301
24									
25	Number of Bills		87,264	72,612	36	13,644	504	156	312
26									
27	**Customer-charge Components**		**$18.97**	**$17.82**	**$28.98**	**$21.30**	**$126.60**	**$15.96**	**$10.58**
28									
29	Distribution Plant in Service- Cost		30,661,045	19,903,356	46,047	4,765,519	5,034,040	351,290	560,794
30	Services / Meters % of Distribution Plant		22.0%	27.1%	5.6%	25.4%	2.6%	2.7%	0.0%
31	ADIT		(336,658)	(220,577)	(489)	(52,159)	(53,648)	(3,760)	(6,025)
32									
33	Income tax gross-up		27.75%	27.75%	27.75%	27.75%	27.75%	27.75%	27.75%
34	GRT gross-up		6.18%	6.18%	6.17%	6.18%	6.16%	6.23%	6.22%

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Line	Account	No.	Balance	Allocator	Supply	Trans-	SubTrans-	Primary	Secondary	Billing		Labor	Labor %
					1	2	3	4	5	6			
1	**I. ELECTRIC PLANT IN SERVICE**												
2	INTANGIBLE PLANT												
3	Organization	302	0	DistPt	0	0	0	0	0	0	-		
4	EDI Software	303	0	Bill	0	0	0	0	0	0	-		
5	Total INTANGIBLE Plant		0		0	0	0	0	0	0	-		
6													
7	**C. TRANSMISSION PLANT**										-		
8	Transmission Plant	361	0	Tran	0	0	0	0	0	0	-		
9	Total TRANSMISSION Plant	350-359	0		0	0	0	0	0	0	-		
10													
11	**D. DISTRIBUTION PLANT**												
12	Land and Land Rights	360	21,453	Prim	0	0	0	21,453	0	0	-		
13	Station Equipment	362	776,412	Prim	0	0	0	776,412	0	0	-		
14	Poles, Towers and Fixtures	364	4,934,235	OH_Cond	0	0	0	3,718,703	1,215,532	0	-		
15	OH Conductors and Devices	365	9,866,317	OH_Cond	0	0	0	7,435,783	2,430,534	0	-		
16	UG Conduits and Conductors	366	4,063,329	UG_Cond	0	0	0	1,998,888	2,064,441	0	-		
17	Line Transformers	368	3,430,881	Trans	0	0	0	0	3,430,881	0	-		
18	Services	369	4,949,542	Sec	0	0	0	0	4,949,542	0	-		
19	Meters	370	1,798,757	Bill	0	0	0	0	0	1,798,757	-		
20	Street Lighting	373	820,118	Sec	0	0	0	0	820,118	0	-		
21	Total DISTRIBUTION Plant	360-373	30,661,045		0	0	0	13,951,239	14,911,049	1,798,757	-		
22													
23	**E. GENERAL PLANT**												
24	General Plant	389	4,280,032	Labor	0	0	0	1,934,196	964,320	1,381,516	-		
25	Communication Equip	398	428,037	Labor	0	0	0	193,435	96,440	138,163	-		
26	Total GENERAL Plant	389-399	4,708,069		0	0	0	2,127,631	1,060,759	1,519,678	-		
27													
28	**TOTAL UTILITY PLANT**		35,369,114		0	0	0	16,078,870	15,971,808	3,318,436	-		
29													

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Line	Account	No.	Balance	Allocator	Supply	Trans-	SubTrans-	Primary	Secondary	Billing		Labor	Labor %
					1	2	3	4	5	6			
30	**II. DEPRECIATION RESERVE**												
31	Intangible Plant	108.3	0	IntanPt	0	0	0	0	0	0	-		
32	Transmission Plant	108.5	0	Tran	0	0	0	0	0	0	-		
33	Station Equipment	108.5	763,782	Prim	0	0	0	763,782	0	0	-		
34	Poles, Towers and Fixtures	108.6	3,612,745	OH_Cond	0	0	0	2,722,758	889,988	0	-		
35	OH Conductors and Devices	108.6	2,888,827	OH_Cond	0	0	0	2,177,174	711,653	0	-		
36	UG Conduits and Conductors	108.6	2,587,766	UG_Cond	0	0	0	1,273,009	1,314,757	0	-		
37	Line Transformers	108.6	2,598,828	Trans	0	0	0	0	2,598,828	0	-		
38	Services	108.6	2,261,922	Sec	0	0	0	0	2,261,922	0	-		
39	Meters	108.6	102,702	Bill	0	0	0	0	0	102,702	-		
40	Street Lighting	108.6	170,989	Sec	0	0	0	0	170,989	0	-		
41	General Plant	108.6	3,202,220	GenPtxL	0	0	0	1,447,121	721,481	1,033,618	-		
35	Total DEPRECIATION RESERVE	108	18,189,781		0	0	0	8,383,843	8,669,618	1,136,320	-		
42													
43	**III. OTHER RATE BASE ITEMS**												
44	Cash Working Capital	131	481,732	OpExp_Dist	0	0	0	224,765	115,259	141,708	-		
45	CWIP	131	0	Plant	0	0	0	0	0	0	-		
45	Materials & Supplies	255	328,809	OpExp_Dist	0	0	0	153,415	78,671	96,724	-		
46	Customer Deposits		(189,068)	Bill	0	0	0	0	0	(189,068)	-		
47	ADIT / EDIT	154	(336,658)	Plant	0	0	0	(153,046)	(152,027)	(31,586)	-		
48	Accrued Pension / OPEB	182	(264,804)	Labor	0	0	0	(119,668)	(59,662)	(85,474)	-		
49	Total OTHER RATE BASE ITEMS	131-283	20,011		0	0	0	105,466	(17,759)	(67,697)	-		
50													
51	**TOTAL RATE BASE**		17,199,344		0	0	0	7,800,493	7,284,432	2,114,419	-		
52			17,199,344										

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Line	Account	No.	Balance	Allocator	Supply 1	Trans- 2	SubTrans- 3	Primary 4	Secondary 5	Billing 6		Labor	Labor %
53	**I. OPERATING AND MAINTENANCE EXPENSES**												
54	**B. TRANSMISSION EXPENSE**												
55	Transmission Expense		0	Tran	0	0	0	0	0	0	-	0	0
56	Total TRANSMISSION Expense		0		0	0	0	0	0	0			
57													
58	**C. DISTRIBUTION OPER. & MAINT. EXPENSE**												
59	Ops Supv & Engineering	580	154,958	D-Labor-Op	0	0	0	90,712	44,073	20,172	-	65,639	42.36%
60	Station Expenses	582	14,046	Prim	0	0	0	14,046	0	0	-	8,446	60.13%
61	OH Line Expenses	583	242,072	OH_Cond	0	0	0	182,438	59,634	0	-	106,207	43.87%
62	Street Lighting Expenses	585	5,137	Sec	0	0	0	0	5,137	0	-	2,438	47.47%
63	Meter Expenses	586	50,712	Bill	0	0	0	0	0	50,712	-	18,234	35.96%
64	Customer Installation Expenses	587	56,416	Bill	0	0	0	0	0	56,416	-	16,746	29.68%
65	Misc. Distribution Expenses	588	495,254	OH_UG	0	0	0	292,188	203,066	0	-	116,645	23.55%
66	Rents	589	525	DistPt	0	0	0	239	255	31	-	0	0.00%
67	Maint Supv & Engineering	590	0	None	0	0	0	0	0	0	-	0	0.00%
68	Maint of Station Equip	592	17,209	Prim	0	0	0	17,209	0	0	-	1,134	6.59%
69	Maint of OH Lines	593	826,836	OH_Cond	0	0	0	623,148	203,688	0	-	142,193	17.20%
70	Maint of UG Lines	594	14,827	UG_Cond	0	0	0	7,294	7,533	0	-	6,923	46.70%
71	Maint of Line Transformers	595	27,468	Trans	0	0	0	0	27,468	0	-	9,440	34.37%
72	Maint of Lighting	596	24,187	Sec	0	0	0	0	24,187	0	-	10,192	42.14%
73	Maint of Misc. Plant	599	0	DistPt	0	0	0	0	0	0	-	0	0.00%
74	Total DISTR. OPER. & MAINT. EXP.	500-599	1,929,647		0	0	0	1,227,274	575,041	127,331	-	504,238	
75	Distribution Expense		1,929,647		0	0	0	1,227,274	575,041	127,331	-		
76	**D. CUSTOMER ACCOUNTS AND SERVICE**												
77	Supervision	901	0	None	0	0	0	0	0	0	-	0	0.00%
78	Meter Reading Exp	902	26,000	Bill	0	0	0	0	0	26,000	-	0	0.00%
79	Customer Records & Coll	903	492,479	Bill	0	0	0	0	0	492,479	-	176,064	35.75%
80	Uncollectible Accounts	904	30,900	Bill	0	0	0	0	0	30,900	-	0	0.00%
81	Subtotal - Customer Accounts Exp.	901-905	549,379		0	0	0	0	0	549,379	-	176,064	
82	Total CUST. ACCT. & SERV. EXP.	901-919	549,379		0	0	0	0	0	549,379	-	176,064	
83												680,301	

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Line	Account	No.	Balance	Allocator	Supply	Trans-	SubTrans-	Primary	Secondary	Billing		Labor	Labor %
					1	2	3	4	5	6			
84	**E. ADMINISTRATIVE AND GENERAL**												
85	Administrative & General Salaries	920	884,948	Labor	0	0	0	399,918	199,385	285,645	-		
86	Office Supplies & Expenses	921	151,265	Labor	0	0	0	68,358	34,081	48,826	-		
87	Outside Services Employed	923	38,110	Labor_Pt	0	0	0	17,274	12,898	7,938	-		
88	Property Insurance	924	11,059	Plant	0	0	0	5,027	4,994	1,038	-		
89	Injuries and Damages	925	28,907	Plant	0	0	0	13,141	13,054	2,712	-		
90	Employee Pensions & Benefits	926	8,755	Labor	0	0	0	3,956	1,973	2,826	-		
91	Regulatory Commission Expense	928	108,889	Bill	0	0	0	0	0	108,889	-		
92	Miscellaneous General Expense	930	114,218	Labor_Pt	0	0	0	51,770	38,656	23,792	-		
89	Maint General Property	932	165,455	Plant	0	0	0	75,216	74,716	15,524	-		
93	Total A&G Expense	920-932	1,511,606		0	0	0	634,662	379,755	497,189	-		
94													
95	TOTAL OPERATING EXPENSES		3,990,632		0	0	0	1,861,936	954,797	1,173,899	-		
96													
97	**II. DEPRECIATION EXPENSE**												
98	Intangible Plant	0	0	Bill	0	0	0	0	0	0	-		
99	Station Equipment	361/362	4,197	Prim	0	0	0	4,197	0	0	-		
100	Poles, Towers and Fixtures	364	196,900	OH_Cond	0	0	0	148,394	48,506	0	-		
101	OH Conductors and Devices	364	380,183	OH_Cond	0	0	0	286,526	93,657	0	-		
102	UG Conduits and Conductors	364	158,473	UG_Cond	0	0	0	77,958	80,515	0	-		
103	Line Transformers	364	133,449	Trans	0	0	0	0	133,449	0	-		
104	Services	364	191,856	Sec	0	0	0	0	191,856	0	-		
105	Meters	364	70,794	Bill	0	0	0	0	0	70,794	-		
106	Street Lighting	364	45,208	Sec	0	0	0	0	45,208	0	-		
107	General Plant	364	228,938	GenPtxL	0	0	0	103,460	51,581	73,897	-		
108	Total DEPRECIATION Expense	403	1,409,998		0	0	0	620,535	644,772	144,691	-		
109													
110	**III. TAXES and OTHER**												
111	**A. GENERAL TAXES**												
112	Payroll related	408.3	0	None	0	0	0	0	0	0	-		
113	PURTA, Real estate	408.16	15,062	Plant	0	0	0	6,847	6,802	1,413	-		
114	PUC Assessment		63,038	RateBase	0	0	0	28,590	26,698	7,750	-		
115	PA Use Tax	408.1	7,604	Plant	0	0	0	3,457	3,434	713	-		
116	Subtotal - General Taxes		85,704		0	0	0	38,894	36,934	9,876	-		
117													
118	**B. GROSS RECEIPTS TAX**												
119	Gross Receipts tax		357,253	GRT_RevxT	0	0	0	162,698	116,136	78,419	-		
120	Subtotal- Gross Receipts tax		357,253		0	0	0	162,698	116,136	78,419	-		
121													

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Citizens Electric Company of Lewisburg
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Line	Account	No.	Balance	Allocator	Supply	Trans-	SubTrans-	Primary	Secondary	Billing		Labor	Labor %
					1	2	3	4	5	6			
122	**B. FEDERAL / STATE INCOME TAXES**												
123	State Income Tax Expense		(11,138)	StaTax	0	0	0	(4,058)	(7,080)	0	-		
124	Federal Income Tax Expense		609	FedTax	0	0	0	222	387	0	-		
125	Subtotal - Federal / State Income Taxes	409-411	(10,529)		0	0	0	(3,836)	(6,693)	0	-		
126	Total TAXES	408-411	432,429		0	0	0	197,756	146,377	88,295	-		
127													
128	**TOTAL EXPENSES**		5,833,058		0	0	0	2,680,227	1,745,946	1,406,885	-		
129													
130	**IV. OPERATING REVENUES at Present Rates**												
131	Distribution Revenue		6,055,143	DistBill_RR-PF	0	0	0	2,773,578	1,979,820	1,301,745	-		
132	Forfeited Discounts		35,091	Bill	0		0	0	0	35,091	-		
133	Rent For Electric Property		60,240	OH_Cond	0	0	0	45,400	14,840	0	-		
134	Other Electric Revenues		14,038	DistBill_RR-PF	0	0	0	6,430	4,590	3,018	-		
135	Total REVENUES		6,164,512		0	0	0	2,825,408	1,999,250	1,339,855	-		
136													
137	TOTAL EXPENSES		5,833,058		0	0	0	2,680,227	1,745,946	1,406,885	-		
138	**V. NET INCOME at Present Rates**		331,455		0	0	0	145,181	253,303	(67,030)	-		
139			331,455										
140	**SUMMARY REPORT**												
141	OPERATING REVENUES												
142	Utility Revenues	440-446	6,090,234		0	0	0	2,773,578	1,979,820	1,336,837	-		
143	Other Operating Revenues	450-456	74,278		0	0	0	51,830	19,430	3,018	-		
144	Total Operating Revenues		6,164,512		0	0	0	2,825,408	1,999,250	1,339,855	-		
145													
146	OPERATING EXPENSES												
147	Distribution / Transmission	580-599	1,929,647		0	0	0	1,227,274	575,041	127,331	-		
148	Customer Acctg & Service	901-919	549,379		0	0	0	0	0	549,379	-		
149	Admin & General	920-932	1,511,606		0	0	0	634,662	379,755	497,189	-		
150	Total Operating Expenses		3,990,632		0	0	0	1,861,936	954,797	1,173,899	-		
151													
152	Depreciation Expense	403	1,409,998		0	0	0	620,535	644,772	144,691	-		
153	Taxes Other Than Income Tax / Other	408	442,957		0	0	0	201,592	153,070	88,295	-		
154	INCOME BEFORE INCOME TAXES		320,926		0	0	0	141,345	246,611	(67,030)	-		
155	Income Taxes	409-411	(10,529)		0	0	0	(3,836)	(6,693)	0	-		
156	**NET INCOME**		331,455		0	0	0	145,181	253,303	(67,030)	-		
157													
158	**RATE BASE**		17,199,344		0	0	0	7,800,493	7,284,432	2,114,419	-		
159	Return on Rate Base		1.9%		-	-	-	1.9%	3.5%	(3.2%)			
160													

Functions
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Citizens Electric Company of Lewisburg
Embedded Cost of Service Study (ECOSS) (R)
FPFTY Ending December 31, 2026
Funtionalization

Line	Account	No.	Balance	Allocator	Supply	Trans-	SubTrans-	Primary	Secondary	Billing	Labor	Labor %
					1	2	3	4	5	6		
161	**REVENUE REQUIREMENTS**											
162	Target Rate of Return		8.4900%		8.4900%	8.4900%	8.4900%	8.4900%	8.4900%	8.4900%		
163												
164	Rate Base		17,199,344		0	0	0	7,800,493	7,284,432	2,114,419	-	
165											-	
166	Operating expenses		3,896,694		0	0	0	1,833,346	928,098	1,135,249	-	
167	Uncollectibles expense		30,900	BILL	0	0	0	0	0	30,900	-	
168	Depreciation expense		1,409,998		0	0	0	620,535	644,772	144,691	-	
169	Regulatory Commission Expenses		63,038	Plant	0	0	0	28,590	26,698	7,750	-	
170	General taxes / Other		85,704		0	0	0	38,894	36,934	9,876	-	
171	Subtotal- Operating Costs to recover		5,486,333		0	0	0	2,521,365	1,636,503	1,328,466	-	
172												
173	Target Return on Rate Base- After taxes		1,460,224		0	0	0	662,262	618,448	179,514	-	
174												
175	Income taxes to recover		405,208	27.75%	0	0	0	183,776	171,617	49,815	-	
176				21.72%								
177	Subtotal- Rev Req before GRT		7,351,765		0	0	0	3,367,402	2,426,568	1,557,795	-	
178	GRT needed		454,093	6.24%	0	0	0	206,882	150,198	97,013	-	
179	**TOTAL REVENUE REQUIREMENT**		7,805,858		0	0	0	3,574,284	2,576,766	1,654,808	-	
180												
181	Revenue at Present rates		6,164,512		0	0	0	2,825,408	1,999,250	1,339,855	-	
182	Revenue Excess (Deficiency)		(1,641,345)		0	0	0	(748,875)	(577,517)	(314,953)	-	
183												

Classify
Classification
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Citizens Electric Company of Lewisburg
Embedded Cost of Service Study (ECOSS) (R)
FPFTY Ending December 31, 2026
Classification

Line	Account	No.	Secondary	Allocator	Demand	Customer
			1		1	3
1	**I. ELECTRIC PLANT IN SERVICE**					
2	INTANGIBLE PLANT					
3	Organization	302	0	Sec-Pt	0	0
4	EDI Software	303	0	Customer	0	0
5	Total INTANGIBLE Plant		0		0	0
6						
7	**C. TRANSMISSION PLANT**					
8	Transmission Plant	361	0	None	0	0
9	Total TRANSMISSION Plant	350-359	0		0	0
10						
11	**D. DISTRIBUTION PLANT**					
12	Land and Land Rights	360	0	None	0	0
13	Station Equipment	362	0	None	0	0
14	Poles, Towers and Fixtures	364	1,215,532	PTF-Sec-Z	234,698	980,835
15	OH Conductors and Devices	365	2,430,534	OH-Sec-Z	549,317	1,881,217
16	UG Conduits and Conductors	366	2,064,441	UG-Sec-Z	885,449	1,178,992
17	Line Transformers	368	3,430,881	Demand	3,430,881	0
18	Services	369	4,949,542	Customer	0	4,949,542
19	Meters	370	0	None	0	0
20	Street Lighting	373	820,118	Customer	0	820,118
21	Total DISTRIBUTION Plant	360-373	14,911,049		5,100,346	9,810,703
22						
23	**E. GENERAL PLANT**					
24	General Plant	389	964,320	Sec-Lab	368,320	596,000
25	Communication Equip	398	96,440	Sec-Lab	36,835	59,605
26	Total GENERAL Plant	389-399	1,060,759		405,155	655,605
27						
28	**TOTAL UTILITY PLANT**		15,971,808		5,505,500	10,466,308
29						

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Citizens Electric Company of Lewisburg
Embedded Cost of Service Study (ECOSS) (R)
FPFTY Ending December 31, 2026
Classification

Line	Account	No.	Secondary	Allocator	Demand	Customer
			1		1	3
30	**II. DEPRECIATION RESERVE**					
31	Intangible Plant	108.3	0	Sec-Pt	0	0
32	Transmission Plant	108.5	0	None	0	0
33	Station Equipment	108.5	0	None	0	0
34	Poles, Towers and Fixtures	108.6	889,988	PTF-Sec-Z	171,841	718,147
35	OH Conductors and Devices	108.6	711,653	OH-Sec-Z	160,838	550,814
36	UG Conduits and Conductors	108.6	1,314,757	UG-Sec-Z	563,906	750,851
37	Line Transformers	108.6	2,598,828	Demand	2,598,828	0
38	Services	108.6	2,261,922	Customer	0	2,261,922
39	Meters	108.6	0	None	0	0
40	Street Lighting	108.6	170,989	Customer	0	170,989
41	General Plant	108.6	721,481	Sec-GenPt	275,568	445,913
35	Total DEPRECIATION RESERVE	108	8,669,618		3,770,982	4,898,636
42						
43	**III. OTHER RATE BASE ITEMS**					
44	Cash Working Capital	131	115,259	Sec-OpExp	43,560	71,699
45	CWIP	131	0	Sec-Pt	0	0
45	Materials & Supplies	255	78,671	Sec-OpExp	29,732	48,939
46	Customer Deposits		0	None	0	0
47	ADIT / EDIT	154	(152,027)	Sec-Pt	(52,404)	(99,623)
48	Accrued Pension / OPEB	182	(59,662)	Sec-Lab	(22,788)	(36,874)
49	Total OTHER RATE BASE ITEMS	131-283	(17,759)		(1,899)	(15,860)
50						
51	**TOTAL RATE BASE**		7,284,432		1,732,619	5,551,812
52						
53	**I. OPERATING AND MAINTENANCE EXPENSE**					

Classify
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Citizens Electric Company of Lewisburg
Embedded Cost of Service Study (ECOSS) (R)
FPFTY Ending December 31, 2026
Classification

Line	Account	No.	Secondary	Allocator	Demand	Customer
54	**B. TRANSMISSION EXPENSE**					
55	Transmission Expense		0	None	0	0
56	Total TRANSMISSION Expense		0		0	0
57						
58	**C. DISTRIBUTION OPER. & MAINT. EX**					
59	Ops Supv & Engineering	580	44,073	Sec-Lab	16,834	27,240
60	Station Expenses	582	0	None	0	0
61	OH Line Expenses	583	59,634	OH-Sec-Z	13,478	46,156
62	Street Lighting Expenses	585	5,137	Customer	0	5,137
63	Meter Expenses	586	0	None	0	0
64	Customer Installation Expenses	587	0	None	0	0
65	Misc. Distribution Expenses	588	203,066	Sec-OH_UG	113,084	89,982
66	Rents	589	255	Sec-Pt	88	167
67	Maint Supv & Engineering	590	0	Sec-Lab	0	0
68	Maint of Station Equip	592	0	None	0	0
69	Maint of OH Lines	593	203,688	OH-Sec-Z	46,035	157,653
70	Maint of UG Lines	594	7,533	UG-Sec-Z	3,231	4,302
71	Maint of Line Transformers	595	27,468	Demand	27,468	0
72	Maint of Lighting	596	24,187	Customer	0	24,187
73	Maint of Misc. Plant	599	0	Sec-Pt	0	0
74	Total DISTR. OPER. & MAINT. EXP.	500-599	575,041		220,217	354,824
75	Distribution Expense		575,041		220,217	354,824
76	**D. CUSTOMER ACCOUNTS AND SERVICE**					
77	Supervision	901	0	None	0	0
78	Meter Reading Exp	902	0	None	0	0
79	Customer Records & Coll	903	0	None	0	0
80	Uncollectible Accounts	904	0	None	0	0
81	Subtotal - Customer Accounts Exp.	901-905	0		0	0
82	Total CUST. ACCT. & SERV. EXP.	901-919	0		0	0
83						

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FPFTY Ending December 31, 2026
Classification

Line	Account	No.	Secondary	Allocator	Demand	Customer
			1		1	4
84	**E. ADMINISTRATIVE AND GENERAL**					
85	Administrative & General Salaries	920	199,385	Sec-Lab	76,155	123,230
86	Office Supplies & Expenses	921	34,081	Sec-Lab	13,017	21,064
87	Outside Services Employed	923	12,898	Sec-LabPt	4,686	8,212
88	Property Insurance	924	4,994	Sec-Pt	1,721	3,273
89	Injuries and Damages	925	13,054	Sec-Pt	4,500	8,554
90	Employee Pensions & Benefits	926	1,973	Sec-Lab	753	1,219
91	Regulatory Commission Expense	928	0	Sec-Pt	0	0
92	Miscellaneous General Expense	930	38,656	Sec-LabPt	14,045	24,611
89	Maint General Property	932	74,716	Sec-Pt	25,755	48,961
93	Total A&G Expense	920-932	379,755		140,631	239,124
94						
95	TOTAL OPERATING EXPENSES		954,797		360,848	593,948
96						
97	**II. DEPRECIATION EXPENSE**					
98	Intangible Plant		0	None	0	0
99	Station Equipment	361/362	0	None	0	0
100	Poles, Towers and Fixtures	364	48,506	PTF-Sec-Z	9,366	39,140
101	OH Conductors and Devices	364	93,657	OH-Sec-Z	21,167	72,490
102	UG Conduits and Conductors	364	80,515	UG-Sec-Z	34,533	45,982
103	Line Transformers	364	133,449	Demand	133,449	0
104	Services	364	191,856	Customer	0	191,856
105	Meters	364	0	None	0	0
106	Street Lighting	364	45,208	Customer	0	45,208
107	General Plant	364	51,581	Sec-GenPt	19,701	31,880
108	Total DEPRECIATION Expense	403	644,772		218,217	426,555
109						
110	**III. TAXES and OTHER**					
111	**A. GENERAL TAXES**					
112	Payroll related	408	0	None	0	0
113	PURTA, Real estate	408.16	6,802	Sec-Pt	2,345	4,457
114	PUC Assessment		26,698	Sec-RB	6,350	20,348
115	PA Use Tax	408	3,434	Sec-Pt	1,184	2,250
116	Subtotal - General Taxes		36,934		9,878	27,055
117						
118	**B. GROSS RECEIPTS TAX**					
119	Gross Receipts tax		116,136	Sec-Rev	38,011	78,125
120	Subtotal- Gross Receipts tax		116,136		38,011	78,125
121						

Classify
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Citizens Electric Company of Lewisburg
Embedded Cost of Service Study (ECOSS) (R)
FPFTY Ending December 31, 2026
Classification

Line	Account	No.	Secondary	Allocator	Demand	Customer
			1		1	4
122	**B. FEDERAL / STATE INCOME TAXES**					
123	State Income Tax Expense		(7,080)	Sec-StaTax	(729)	(6,351)
124	Federal Income Tax Expense		387	Sec-FedTax	40	348
125	Subtotal - Federal / State Income Taxes	409-411	(6,693)		(689)	(6,003)
126	Total TAXES	408-411	146,377		47,200	99,177
127						
128	**TOTAL EXPENSES**		1,745,946		626,265	1,119,681
129						
130	**IV. OPERATING REVENUES at Present Rates**					
131	Distribution Revenue		1,979,820	Sec-RetRRPF	647,985	1,331,834
132	Forfeited Discounts		0	Sec-RetRRPF	0	0
133	Rent For Electric Property		14,840	PTF-Sec-Z	2,865	11,975
134	Other Electric Revenues		4,590	Sec-RetRRPF	1,502	3,088
135	Total REVENUES		1,999,250		652,353	1,346,896
136						
137	TOTAL EXPENSES		1,745,946		626,265	1,119,681
138	**V. NET INCOME at Present Rates**		253,303		26,088	227,215
139						
140	**SUMMARY REPORT**					
141	OPERATING REVENUES					
142	Utility Revenues	440-446	1,979,820		647,985	1,331,834
143	Other Operating Revenues	450-456	19,430		4,368	15,062
144	Total Operating Revenues		1,999,250		652,353	1,346,896
145						
146	OPERATING EXPENSES					
147	Distribution / Transmission	580-599	575,041		220,217	354,824
148	Customer Acctg & Service	901-919	0		0	0
149	Admin & General	920-932	379,755		140,631	239,124
150	Total Operating Expenses		954,797		360,848	593,948
151						
152	Depreciation Expense	403	644,772		218,217	426,555
153	Taxes Other Than Income Tax / Other	408	153,070		47,889	105,181
154	INCOME BEFORE INCOME TAXES		246,611		25,399	221,212
155	Income Taxes	409-411	(6,693)		(689)	(6,003)
156	**NET INCOME**		253,303		26,088	227,215
157						
158	**RATE BASE**		7,284,432		1,732,619	5,551,812
159	Return on Rate Base					

Classify
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Citizens Electric Company of Lewisburg
Embedded Cost of Service Study (ECOSS) (R)
FPFTY Ending December 31, 2026
Classification

Line	Account	No.	Secondary	Allocator	Demand	Customer
			1		1	3
160						
161	**REVENUE REQUIREMENTS**					
162	Target Rate of Return		8.4900%		8.4900%	8.4900%
163						
164	Rate Base		7,284,432		1,732,619	5,551,812
165						
166	Operating expenses		928,098		354,498	573,600
167	Uncollectibles expense		0	None	0	0
168	Depreciation expense		644,772		218,217	426,555
169	Regulatory Commission Expenses		26,698	Sec-Pt	6,350	20,348
170	General taxes / Other		36,934		9,878	27,055
171	Subtotal- Operating Costs to recover		1,636,503		588,943	1,047,559
172						
173	Target Return on Rate Base- After taxes		618,448		147,099	471,349
174						
175	Income taxes to recover	27.75%	171,617		40,820	130,798
176						
177	Subtotal- Rev Req before GRT		2,426,568		776,862	1,649,706
178	GRT needed	6.24%	150,198		48,201	101,997
179	**TOTAL REVENUE REQUIREMENT**		2,576,766		825,064	1,751,702
180						

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Class Allocation- Primary Demand
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Citizens Electric Company of Lewisburg
Embedded Cost of Service Study (ECOSS) (R)
FPFTY Ending December 31, 2026
Class Allocation- Primary Demand

Line	Account	No.	Balance	Allocator	RS	SH	GLP-1	GLP-3	MBL	OL
1	**I. ELECTRIC PLANT IN SERVICE**									
2	INTANGIBLE PLANT									
3	Organization	302	0	PriD-Pt	0	0	0	0	0	0
4	EDI Software	303	0	PriD-Lab	0	0	0	0	0	0
5	Total INTANGIBLE Plant		0		0	0	0	0	0	0
6										
7	**C. TRANSMISSION PLANT**									
8	Transmission Plant	361	0	None	0	0	0	0	0	0
9	Total TRANSMISSION Plant	350-359	0		0	0	0	0	0	0
10										
11	**D. DISTRIBUTION PLANT**									
12	Land and Land Rights	360	21,453	NCP-Prim	13,110	35	3,119	5,141	10	38
13	Station Equipment	362	776,412	NCP-Prim	474,468	1,277	112,873	186,053	358	1,383
14	Poles, Towers and Fixtures	364	3,718,703	NCP-Prim	2,272,510	6,116	540,616	891,118	1,716	6,626
15	OH Conductors and Devices	365	7,435,783	NCP-Prim	4,544,028	12,229	1,080,997	1,781,847	3,432	13,250
16	UG Conduits and Conductors	366	1,998,888	NCP-Prim	1,221,526	3,287	290,594	478,996	923	3,562
17	Line Transformers	368	0	None	0	0	0	0	0	0
18	Services	369	0	None	0	0	0	0	0	0
19	Meters	370	0	None	0	0	0	0	0	0
20	Street Lighting	373	0	None	0	0	0	0	0	0
21	Total DISTRIBUTION Plant	360-373	13,951,239		8,525,642	22,945	2,028,198	3,343,155	6,439	24,860
22										
23	**E. GENERAL PLANT**									
24	General Plant	389	1,934,196	PriD-Lab	1,181,993	3,181	281,189	463,494	893	3,447
25	Communication Equip	398	193,435	PriD-Lab	118,209	318	28,121	46,353	89	345
26	Total GENERAL Plant	389-399	2,127,631		1,300,202	3,499	309,310	509,847	982	3,791
27										
28	**TOTAL UTILITY PLANT**		16,078,870		9,825,844	26,444	2,337,509	3,853,002	7,421	28,651
29										

PrimDem
Class Allocation- Primary Demand
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E-4A (I

Citizens Electric Company of Lewisburg
Embedded Cost of Service Study (ECOSS) (R)
FPFTY Ending December 31, 2026
Class Allocation- Primary Demand

Line	Account	No.	Balance	Allocator	RS	SH	GLP-1	GLP-3	MBL	OL
30	**II. DEPRECIATION RESERVE**									
31	Intangible Plant	108.3	0	NCP-Prim	0	0	0	0	0	0
32	Transmission Plant	108.5	0	None	0	0	0	0	0	0
33	Station Equipment	108.5	763,782	NCP-Prim	466,749	1,256	111,037	183,026	352	1,361
34	Poles, Towers and Fixtures	108.6	2,722,758	NCP-Prim	1,663,885	4,478	395,828	652,458	1,257	4,852
35	OH Conductors and Devices	108.6	2,177,174	NCP-Prim	1,330,477	3,581	316,512	521,719	1,005	3,880
36	UG Conduits and Conductors	108.6	1,273,009	NCP-Prim	777,939	2,094	185,067	305,053	588	2,268
37	Line Transformers	108.6	0	None	0	0	0	0	0	0
38	Services	108.6	0	None	0	0	0	0	0	0
39	Meters	108.6	0	None	0	0	0	0	0	0
40	Street Lighting	108.6	0	None	0	0	0	0	0	0
41	General Plant	108.6	1,447,121	PriD-Lab	884,340	2,380	210,379	346,776	668	2,579
35	Total DEPRECIATION RESERVE	108	8,383,843		5,123,391	13,788	1,218,824	2,009,032	3,869	14,939
42										
43	**III. OTHER RATE BASE ITEMS**									
44	Cash Working Capital	131	224,765	PriD-OpExp	137,355	370	32,676	53,861	104	401
45	CWIP	131	0	PriD-Pt	0	0	0	0	0	0
45	Materials & Supplies	255	153,415	PriD-OpExp	93,752	252	22,303	36,763	71	273
46	Customer Deposits		0	None	0	0	0	0	0	0
47	ADIT / EDIT	154	(153,046)	PriD-Pt	(93,527)	(252)	(22,249)	(36,675)	(71)	(273)
48	Accrued Pension / OPEB	182	(119,668)	PriD-Lab	(73,129)	(197)	(17,397)	(28,676)	(55)	(213)
49	Total OTHER RATE BASE ITEMS	131-283	105,466		64,451	173	15,332	25,273	49	188
50										
51	**TOTAL RATE BASE**		7,800,493		4,766,904	12,829	1,134,017	1,869,243	3,600	13,900
52										

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Class Allocation- Primary Demand
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Citizens Electric Company of Lewisburg
Embedded Cost of Service Study (ECOSS) (R)
FPFTY Ending December 31, 2026
Class Allocation- Primary Demand

Line	Account	No.	Balance	Allocator	RS	SH	GLP-1	GLP-3	MBL	OL
53	**I. OPERATING AND MAINTENANCE EXPENSES**									
54	**B. TRANSMISSION EXPENSE**									
55	Transmission Expense		0	None	0	0	0	0	0	0
56	Total TRANSMISSION Expense		0		0	0	0	0	0	0
57										
58	**C. DISTRIBUTION OPER. & MAINT. E**									
59	Ops Supv & Engineering	580	90,712	PriD-Lab	55,435	149	13,188	21,738	42	162
60	Station Expenses	582	14,046	NCP-Prim	8,584	23	2,042	3,366	6	25
61	OH Line Expenses	583	182,438	NCP-Prim	111,489	300	26,522	43,718	84	325
62	Street Lighting Expenses	585	0	None	0	0	0	0	0	0
63	Meter Expenses	586	0	None	0	0	0	0	0	0
64	Customer Installation Expenses	587	0	None	0	0	0	0	0	0
65	Misc. Distribution Expenses	588	292,188	NCP-Prim	178,557	481	42,478	70,017	135	521
66	Rents	589	239	NCP-Prim	146	0	35	57	0	0
67	Maint Supv & Engineering	590	0	PriD-Lab	0	0	0	0	0	0
68	Maint of Station Equip	592	17,209	NCP-Prim	10,517	28	2,502	4,124	8	31
69	Maint of OH Lines	593	623,148	NCP-Prim	380,807	1,025	90,592	149,326	288	1,110
70	Maint of UG Lines	594	7,294	NCP-Prim	4,457	12	1,060	1,748	3	13
71	Maint of Line Transformers	595	0	None	0	0	0	0	0	0
72	Maint of Lighting	596	0	None	0	0	0	0	0	0
73	Maint of Misc. Plant	599	0	NCP-Prim	0	0	0	0	0	0
74	Total DISTR. OPER. & MAINT. EXP.	500-599	1,227,274		749,991	2,018	178,418	294,093	566	2,187
75	Distribution Expense		1,227,274		749,991	2,018	178,418	294,093	566	2,187
76	**D. CUSTOMER ACCOUNTS AND SERVICE**									
77	Supervision	901	0	None	0	0	0	0	0	0
78	Meter Reading Exp	902	0	None	0	0	0	0	0	0
79	Customer Records & Coll	903	0	None	0	0	0	0	0	0
80	Uncollectible Accounts	904	0	None	0	0	0	0	0	0
81	Subtotal - Customer Accounts Exp.	901-905	0		0	0	0	0	0	0
82	Total CUST. ACCT. & SERV. EXP.	901-919	0		0	0	0	0	0	0
83										

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Line	Account	No.	Balance	Allocator	RS	SH	GLP-1	GLP-3	MBL	OL
84	**E. ADMINISTRATIVE AND GENERAL**									
85	Administrative & General Salaries	920	399,918	PriD-Lab	244,391	658	58,139	95,833	185	713
86	Office Supplies & Expenses	921	68,358	PriD-Lab	41,774	112	9,938	16,381	32	122
87	Outside Services Employed	923	17,274	PriD-LabPt	10,556	28	2,511	4,139	8	31
88	Property Insurance	924	5,027	PriD-Pt	3,072	8	731	1,205	2	9
89	Injuries and Damages	925	13,141	PriD-Pt	8,031	22	1,910	3,149	6	23
90	Employee Pensions & Benefits	926	3,956	PriD-Lab	2,418	7	575	948	2	7
91	Regulatory Commission Expense	928	0	PriD-Pt	0	0	0	0	0	0
92	Miscellaneous General Expense	930	51,770	PriD-LabPt	31,637	85	7,526	12,406	24	92
89	Maint General Property	932	75,216	PriD-Pt	45,965	124	10,935	18,024	35	134
93	Total A&G Expense	920-932	634,662		387,844	1,044	92,266	152,085	293	1,131
94										
95	TOTAL OPERATING EXPENSES		1,861,936		1,137,835	3,062	270,684	446,178	859	3,318
96										
97	**II. DEPRECIATION EXPENSE**									
98	Intangible Plant		0	None	0	0	0	0	0	0
99	Station Equipment	361/362	4,197	NCP-Prim	2,565	7	610	1,006	2	7
100	Poles, Towers and Fixtures	364	148,394	NCP-Prim	90,684	244	21,573	35,560	68	264
101	OH Conductors and Devices	364	286,526	NCP-Prim	175,097	471	41,654	68,661	132	511
102	UG Conduits and Conductors	364	77,958	NCP-Prim	47,641	128	11,333	18,681	36	139
103	Line Transformers	364	0	None	0	0	0	0	0	0
104	Services	364	0	None	0	0	0	0	0	0
105	Meters	364	0	None	0	0	0	0	0	0
106	Street Lighting	364	0	None	0	0	0	0	0	0
107	General Plant	364	103,460	PriD-Lab	63,224	170	15,041	24,792	48	184
108	Total DEPRECIATION Expense	403	620,535		379,211	1,021	90,212	148,700	286	1,106
109										
110	**III. TAXES and OTHER**									
111	**A. GENERAL TAXES**									
112	Payroll related	408	0	None	0	0	0	0	0	0
113	PURTA, Real estate	408.16	6,847	PriD-Pt	4,184	11	995	1,641	3	12
114	PUC Assessment		28,590	RateBase	19,061	35	4,350	3,936	470	738
115	PA Use Tax	408	3,457	PriD-Pt	2,112	6	503	828	2	6
116	Subtotal - General Taxes		38,894		25,358	52	5,848	6,405	475	756
117										
118	**B. GROSS RECEIPTS TAX**									
119	Gross Receipts tax		162,698	Dist_Rev	104,891	235	29,345	24,428	703	3,096
120	Subtotal- Gross Receipts tax		162,698		104,891	235	29,345	24,428	703	3,096
121										

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Line	Account	No.	Balance	Allocator	RS	SH	GLP-1	GLP-3	MBL	OL
122	**B. FEDERAL / STATE INCOME TAXES**									
123	State Income Tax Expense		(4,058)	PreTax-Sta	(2,659)	(6)	(629)	(647)	(45)	(73)
124	Federal Income Tax Expense		222	PreTax-Fed	20	1	128	59	0	14
125	Subtotal - Federal / State Income Taxes	409-411	(3,836)		(2,639)	(5)	(501)	(588)	(45)	(59)
126	Total TAXES	408-411	197,756		127,611	282	34,692	30,246	1,132	3,793
127										
128	**TOTAL EXPENSES**		2,680,227		1,644,656	4,365	395,588	625,124	2,278	8,217
129										
130	**IV. OPERATING REVENUES at Present Rates**									
131	Distribution Revenue		2,773,578	Dist_Rev	1,788,124	4,004	500,257	416,436	11,978	52,779
132	Forfeited Discounts		0	Write-Offs	0	0	0	0	0	0
133	Rent For Electric Property		45,400	NCP-Prim	27,744	75	6,600	10,879	21	81
134	Other Electric Revenues		6,430	Dist_Rev	4,146	9	1,160	965	28	122
135	Total REVENUES		2,825,408		1,820,013	4,088	508,017	428,281	12,027	52,982
136										
137	TOTAL EXPENSES		2,680,227		1,644,656	4,365	395,588	625,124	2,278	8,217
138	**V. NET INCOME at Present Rates**		145,181		175,357	(277)	112,429	(196,843)	9,749	44,765
139										
140	**SUMMARY REPORT**									
141	OPERATING REVENUES									
142	Utility Revenues	440-446	2,773,578		1,788,124	4,004	500,257	416,436	11,978	52,779
143	Other Operating Revenues	450-456	51,830		31,890	84	7,760	11,845	49	203
144	Total Operating Revenues		2,825,408		1,820,013	4,088	508,017	428,281	12,027	52,982
145										
146	OPERATING EXPENSES									
147	Distribution / Transmission	580-599	1,227,274		749,991	2,018	178,418	294,093	566	2,187
148	Customer Acctg & Service	901-919	0		0	0	0	0	0	0
149	Admin & General	920-932	634,662		387,844	1,044	92,266	152,085	293	1,131
150	Total Operating Expenses		1,861,936		1,137,835	3,062	270,684	446,178	859	3,318
151										
152	Depreciation Expense	403	620,535		379,211	1,021	90,212	148,700	286	1,106
153	Taxes Other Than Income Tax / Other	408	201,592		130,249	287	35,193	30,833	1,177	3,852
154	INCOME BEFORE INCOME TAXES		141,345		172,719	(282)	111,929	(197,431)	9,704	44,706
155	Income Taxes	409-411	(3,836)		(2,639)	(5)	(501)	(588)	(45)	(59)
156	**NET INCOME**		145,181		175,357	(277)	112,429	(196,843)	9,749	44,765
157										
158	**RATE BASE**		7,800,493		4,766,904	12,829	1,134,017	1,869,243	3,600	13,900
159	Return on Rate Base		1.86%							
160										

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Line	Account	No.	Balance	Allocator	RS	SH	GLP-1	GLP-3	MBL	OL
161	**REVENUE REQUIREMENTS**									
162	Target Rate of Return		8.4900%		8.4900%	8.4900%	8.4900%	8.4900%	8.4900%	8.4900%
163										
164	Rate Base		7,800,493		4,766,904	12,829	1,134,017	1,869,243	3,600	13,900
165										
166	Operating expenses		1,833,346		1,118,773	3,027	266,334	442,242	389	2,580
167	Uncollectibles expense		0	None	0	0	0	0	0	0
168	Depreciation expense		620,535		379,211	1,021	90,212	148,700	286	1,106
169	Regulatory Commission Expenses		28,590	PriD-Pt	19,061	35	4,350	3,936	470	738
170	General taxes / Other		38,894		25,358	52	5,848	6,405	475	756
171	Subtotal- Operating Costs to recover		2,521,365		1,542,403	4,135	366,743	601,283	1,620	5,180
172										
173	Target Return on Rate Base- After taxes		662,262		404,710	1,089	96,278	158,699	306	1,180
174										
175	Income taxes to recover		183,776	27.75%	112,306	302	26,717	44,038	85	327
176										
177	Subtotal- Rev Req before GRT		3,367,402		2,059,419	5,526	489,738	804,020	2,011	6,687
178	GRT needed		206,882	6.24%	126,512	340	30,074	49,429	122	405
179	**TOTAL REVENUE REQUIREMENT**		3,574,284		2,185,931	5,866	519,812	853,450	2,133	7,092
180										
181	Revenue at Present rates		2,825,408		1,820,013	4,088	508,017	428,281	12,027	52,982
182	Revenue Excess (Deficiency)		(748,875)		(365,917)	(1,778)	(11,795)	(425,169)	9,894	45,890

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Line	Account	No.	Balance	Allocator	RS	SH	GLP-1	GLP-3	MBL	OL
1	**I. ELECTRIC PLANT IN SERVICE**									
2	INTANGIBLE PLANT									
3	Organization	302	0	SecD-Pt	0	0	0	0	0	0
4	EDI Software	303	0	SecD-Lab	0	0	0	0	0	0
5	Total INTANGIBLE Plant		0		0	0	0	0	0	0
6										
7	**C. TRANSMISSION PLANT**									
8	Transmission Plant	361	0	None	0	0	0	0	0	0
9	Total TRANSMISSION Plant	350-359	0		0	0	0	0	0	0
10										
11	**D. DISTRIBUTION PLANT**									
12	Land and Land Rights	360	0	None	0	0	0	0	0	0
13	Station Equipment	362	0	None	0	0	0	0	0	0
14	Poles, Towers and Fixtures	364	234,698	NCP-Sec	163,444	440	38,882	31,331	123	477
15	OH Conductors and Devices	365	549,317	NCP-Sec	382,547	1,030	91,006	73,331	289	1,115
16	UG Conduits and Conductors	366	885,449	NCP-Sec	616,630	1,660	146,693	118,203	466	1,798
17	Line Transformers	368	3,430,881	NCP-Ltr	1,461,574	15,748	616,716	1,311,723	5,168	19,953
18	Services	369	0	None	0	0	0	0	0	0
19	Meters	370	0	None	0	0	0	0	0	0
20	Street Lighting	373	0	None	0	0	0	0	0	0
21	Total DISTRIBUTION Plant	360-373	5,100,346		2,624,195	18,877	893,296	1,534,589	6,046	23,343
22										
23	**E. GENERAL PLANT**									
24	General Plant	389	368,320	SecD-Lab	238,212	874	61,972	65,997	260	1,004
25	Communication Equip	398	36,835	SecD-Lab	23,823	87	6,198	6,600	26	100
26	Total GENERAL Plant	389-399	405,155		262,036	961	68,170	72,598	286	1,104
27										
28	**TOTAL UTILITY PLANT**		5,505,500		2,886,231	19,838	961,466	1,607,186	6,332	24,447
29										

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Line	Account	No.	Balance	Allocator	RS	SH	GLP-1	GLP-3	MBL	OL
30	**II. DEPRECIATION RESERVE**									
31	Intangible Plant	108.3	0	NCP-Sec	0	0	0	0	0	0
32	Transmission Plant	108.5	0	None	0	0	0	0	0	0
33	Station Equipment	108.5	0	None	0	0	0	0	0	0
34	Poles, Towers and Fixtures	108.6	171,841	NCP-Sec	119,671	322	28,469	22,940	90	349
35	OH Conductors and Devices	108.6	160,838	NCP-Sec	112,008	301	26,646	21,471	85	327
36	UG Conduits and Conductors	108.6	563,906	NCP-Sec	392,706	1,057	93,422	75,279	297	1,145
37	Line Transformers	108.6	2,598,828	NCP-Ltr	1,107,115	11,929	467,150	993,605	3,915	15,114
38	Services	108.6	0	None	0	0	0	0	0	0
39	Meters	108.6	0	None	0	0	0	0	0	0
40	Street Lighting	108.6	0	None	0	0	0	0	0	0
41	General Plant	108.6	275,568	SecD-Lab	178,225	654	46,366	49,378	195	751
35	Total DEPRECIATION RESERVE	108	3,770,982		1,909,725	14,263	662,054	1,162,673	4,581	17,686
42										
43	**III. OTHER RATE BASE ITEMS**									
44	Cash Working Capital	131	43,560	SecD-OpExp	27,884	106	7,344	8,071	32	123
45	CWIP	131	0	SecD-Pt	0	0	0	0	0	0
45	Materials & Supplies	255	29,732	SecD-OpExp	19,032	73	5,013	5,509	22	84
46	Customer Deposits		0	None	0	0	0	0	0	0
47	ADIT / EDIT	154	(52,404)	SecD-Pt	(27,472)	(189)	(9,152)	(15,298)	(60)	(233)
48	Accrued Pension / OPEB	182	(22,788)	SecD-Lab	(14,738)	(54)	(3,834)	(4,083)	(16)	(62)
49	Total OTHER RATE BASE ITEMS	131-283	(1,899)		4,705	(64)	(629)	(5,801)	(23)	(88)
50										
51	**TOTAL RATE BASE**		1,732,619		981,211	5,511	298,783	438,712	1,728	6,673
52										

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Line	Account	No.	Balance	Allocator	RS	SH	GLP-1	GLP-3	MBL	OL
53	**I. OPERATING AND MAINTENANCE EXPENSES**									
54	**B. TRANSMISSION EXPENSE**									
55	Transmission Expense		0	None	0	0	0	0	0	0
56	Total TRANSMISSION Expense		0		0	0	0	0	0	0
57										
58	**C. DISTRIBUTION OPER. & MAINT. E**									
59	Ops Supv & Engineering	580	16,834	SecD-Lab	10,887	40	2,832	3,016	12	46
60	Station Expenses	582	0	None	0	0	0	0	0	0
61	OH Line Expenses	583	13,478	NCP-Sec	9,386	25	2,233	1,799	7	27
62	Street Lighting Expenses	585	0	None	0	0	0	0	0	0
63	Meter Expenses	586	0	None	0	0	0	0	0	0
64	Customer Installation Expenses	587	0	None	0	0	0	0	0	0
65	Misc. Distribution Expenses	588	113,084	NCP-Sec	78,752	212	18,735	15,096	59	230
66	Rents	589	88	NCP-Sec	61	0	15	12	0	0
67	Maint Supv & Engineering	590	0	None	0	0	0	0	0	0
68	Maint of Station Equip	592	0	None	0	0	0	0	0	0
69	Maint of OH Lines	593	46,035	NCP-Sec	32,059	86	7,627	6,145	24	93
70	Maint of UG Lines	594	3,231	NCP-Sec	2,250	6	535	431	2	7
71	Maint of Line Transformers	595	27,468	NCP-Ltr	11,701	126	4,937	10,502	41	160
72	Maint of Lighting	596	0	None	0	0	0	0	0	0
73	Maint of Misc. Plant	599	0	NCP-Sec	0	0	0	0	0	0
74	Total DISTR. OPER. & MAINT. EXP.	500-599	220,217		145,097	496	36,914	37,002	146	563
75	Distribution Expense		220,217		145,097	496	36,914	37,002	146	563
76	**D. CUSTOMER ACCOUNTS AND SERVICE**									
77	Supervision	901	0	None	0	0	0	0	0	0
78	Meter Reading Exp	902	0	None	0	0	0	0	0	0
79	Customer Records & Coll	903	0	None	0	0	0	0	0	0
80	Uncollectible Accounts	904	0	None	0	0	0	0	0	0
81	Subtotal - Customer Accounts Exp.	901-905	0		0	0	0	0	0	0
82	Total CUST. ACCT. & SERV. EXP.	901-919	0		0	0	0	0	0	0
83										

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Line	Account	No.	Balance	Allocator	RS	SH	GLP-1	GLP-3	MBL	OL
84	**E. ADMINISTRATIVE AND GENERAL**									
85	Administrative & General Salaries	920	76,155	SecD-Lab	49,253	181	12,813	13,646	54	208
86	Office Supplies & Expenses	921	13,017	SecD-Lab	8,419	31	2,190	2,332	9	35
87	Outside Services Employed	923	4,686	SecD-LabPt	2,744	14	803	1,104	4	17
88	Property Insurance	924	1,721	SecD-Pt	902	6	301	503	2	8
89	Injuries and Damages	925	4,500	SecD-Pt	2,359	16	786	1,314	5	20
90	Employee Pensions & Benefits	926	753	SecD-Lab	487	2	127	135	1	2
91	Regulatory Commission Expense	928	0	SecD-Pt	0	0	0	0	0	0
92	Miscellaneous General Expense	930	14,045	SecD-LabPt	8,223	42	2,408	3,308	13	50
89	Maint General Property	932	25,755	SecD-Pt	13,502	93	4,498	7,518	30	114
93	Total A&G Expense	920-932	140,631		85,889	385	23,926	29,860	118	454
94										
95	TOTAL OPERATING EXPENSES		360,848		230,986	880	60,840	66,862	263	1,017
96										
97	**II. DEPRECIATION EXPENSE**									
98	Intangible Plant		0	None	0	0	0	0	0	0
99	Station Equipment	361/362	0	None	0	0	0	0	0	0
100	Poles, Towers and Fixtures	364	9,366	NCP-Sec	6,522	18	1,552	1,250	5	19
101	OH Conductors and Devices	364	21,167	NCP-Sec	14,741	40	3,507	2,826	11	43
102	UG Conduits and Conductors	364	34,533	NCP-Sec	24,049	65	5,721	4,610	18	70
103	Line Transformers	364	133,449	NCP-Ltr	56,850	613	23,988	51,021	201	776
104	Services	364	0	None	0	0	0	0	0	0
105	Meters	364	0	None	0	0	0	0	0	0
106	Street Lighting	364	0	None	0	0	0	0	0	0
107	General Plant	364	19,701	SecD-Lab	12,742	47	3,315	3,530	14	54
108	Total DEPRECIATION Expense	403	218,217		114,904	781	38,082	63,238	249	962
109										
110	**III. TAXES and OTHER**									
111	**A. GENERAL TAXES**									
112	Payroll related	408	0	SecD-Lab	0	0	0	0	0	0
113	PURTA, Real estate	408.16	2,345	SecD-Pt	1,229	8	409	684	3	10
114	PUC Assessment		6,350	RateBase	4,234	8	966	874	104	164
115	PA Use Tax	408	1,184	SecD-Pt	621	4	207	346	1	5
116	Subtotal - General Taxes		9,878		6,083	21	1,582	1,904	108	180
117										
118	**B. GROSS RECEIPTS TAX**									
119	Gross Receipts tax		38,011	Dist_Rev	24,506	55	6,856	5,707	164	723
120	Subtotal- Gross Receipts tax		38,011		24,506	55	6,856	5,707	164	723
121										

SecnDem
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Citizens Electric Company of Lewisburg
Embedded Cost of Service Study (ECOSS) (R)
FPFTY Ending December 31, 2026
Class Allocation- Secondary Demand

Line	Account	No.	Balance	Allocator	RS	SH	GLP-1	GLP-3	MBL	OL
122	**B. FEDERAL / STATE INCOME TAXES**									
123	State Income Tax Expense		(729)	PreTax-Sta	(478)	(1)	(113)	(116)	(8)	(13)
124	Federal Income Tax Expense		40	PreTax-Fed	4	0	23	11	0	2
125	Subtotal - Federal / State Income Taxes	409-411	(689)		(474)	(1)	(90)	(106)	(8)	(11)
126	Total TAXES	408-411	47,200		30,115	74	8,348	7,506	264	892
127										
128	**TOTAL EXPENSES**		626,265		376,005	1,736	107,270	137,605	777	2,871
129										
130	**IV. OPERATING REVENUES at Present Rates**									
131	Distribution Revenue		647,985	Dist_Rev	417,756	935	116,874	97,291	2,798	12,331
132	Forfeited Discounts		0	Write-Offs	0	0	0	0	0	0
133	Rent For Electric Property		2,865	NCP-Sec	1,995	5	475	383	2	6
134	Other Electric Revenues		1,502	Dist_Rev	969	2	271	226	6	29
135	Total REVENUES		652,353		420,720	943	117,620	97,899	2,806	12,365
136										
137	TOTAL EXPENSES		626,265		376,005	1,736	107,270	137,605	777	2,871
138	**V. NET INCOME at Present Rates**		26,088		44,714	(793)	10,349	(39,706)	2,029	9,494
139										
140	**SUMMARY REPORT**									
141	OPERATING REVENUES									
142	Utility Revenues	440-446	647,985		417,756	935	116,874	97,291	2,798	12,331
143	Other Operating Revenues	450-456	4,368		2,964	8	746	608	8	34
144	Total Operating Revenues		652,353		420,720	943	117,620	97,899	2,806	12,365
145										
146	OPERATING EXPENSES									
147	Distribution / Transmission	580-599	220,217		145,097	496	36,914	37,002	146	563
148	Customer Acctg & Service	901-919	0		0	0	0	0	0	0
149	Admin & General	920-932	140,631		85,889	385	23,926	29,860	118	454
150	Total Operating Expenses		360,848		230,986	880	60,840	66,862	263	1,017
151										
152	Depreciation Expense	403	218,217		114,904	781	38,082	63,238	249	962
153	Taxes Other Than Income Tax / Other	408	47,889		30,589	75	8,438	7,611	273	903
154	INCOME BEFORE INCOME TAXES		25,399		44,240	(794)	10,260	(39,811)	2,021	9,483
155	Income Taxes	409-411	(689)		(474)	(1)	(90)	(106)	(8)	(11)
156	**NET INCOME**		26,088		44,714	(793)	10,349	(39,706)	2,029	9,494
157										
158	**RATE BASE**		1,732,619		981,211	5,511	298,783	438,712	1,728	6,673
159	Return on Rate Base		1.51%							
160										

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Citizens Electric Company of Lewisburg
Embedded Cost of Service Study (ECOSS) (R)
FPFTY Ending December 31, 2026
Class Allocation- Secondary Demand

Line	Account	No.	Balance	Allocator	RS	SH	GLP-1	GLP-3	MBL	OL
161	**REVENUE REQUIREMENTS**									
162	Target Rate of Return		8.4900%		8.4900%	8.4900%	8.4900%	8.4900%	8.4900%	8.4900%
163										
164	Rate Base		1,732,619		981,211	5,511	298,783	438,712	1,728	6,673
165										
166	Operating expenses		354,498		226,752	873	59,874	65,987	159	853
167	Uncollectibles expense		0	None	0	0	0	0	0	0
168	Depreciation expense		218,217		114,904	781	38,082	63,238	249	962
169	Regulatory Commission Expenses		6,350	SecD-Pt	4,234	8	966	874	104	164
170	General taxes / Other		9,878		6,083	21	1,582	1,904	108	180
171	Subtotal- Operating Costs to recover		588,943		351,974	1,682	100,504	132,004	621	2,159
172										
173	Target Return on Rate Base- After taxes		147,099		83,305	468	25,367	37,247	147	567
174										
175	Income taxes to recover		40,820	27.75%	23,117	130	7,039	10,336	41	157
176										
177	Subtotal- Rev Req before GRT		776,862		458,395	2,280	132,910	179,586	808	2,882
178	GRT needed		48,201	6.24%	28,418	142	8,247	11,168	50	178
179	**TOTAL REVENUE REQUIREMENT**		825,064		486,813	2,422	141,157	190,754	858	3,060
180										
181	Revenue at Present rates		652,353		420,720	943	117,620	97,899	2,806	12,365
182	Revenue Excess (Deficiency)		(172,711)		(66,093)	(1,479)	(23,537)	(92,855)	1,948	9,305

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Citizens Electric Company of Lewisburg
Embedded Cost of Service Study (ECOSS) (R)
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Class Allocation- Secondary Customer

Line	Account	No.	Balance	Allocator	RS	SH	GLP-1	GLP-3	MBL	OL
1	**I. ELECTRIC PLANT IN SERVICE**									
2	INTANGIBLE PLANT									
3	Organization	302	0	SecC-Pt	0	0	0	0	0	0
4	EDI Software	303	0	SecC-Lab	0	0	0	0	0	0
5	Total INTANGIBLE Plant		0		0	0	0	0	0	0
6										
7	**C. TRANSMISSION PLANT**									
8	Transmission Plant	361	0	None	0	0	0	0	0	0
9	Total TRANSMISSION Plant	350-359	0		0	0	0	0	0	0
10										
11	**D. DISTRIBUTION PLANT**									
12	Land and Land Rights	360	0	None	0	0	0	0	0	0
13	Station Equipment	362	0	None	0	0	0	0	0	0
14	Poles, Towers and Fixtures	364	980,835	Avg-Cust	816,148	405	153,357	5,665	1,753	3,507
15	OH Conductors and Devices	365	1,881,217	Avg-Cust	1,565,352	776	294,134	10,865	3,363	6,726
16	UG Conduits and Conductors	366	1,178,992	Avg-Cust	981,034	486	184,339	6,809	2,108	4,215
17	Line Transformers	368	0	Avg-Cust-Sec	0	0	0	0	0	0
18	Services	369	4,949,542	Services_Cost	4,113,442	1,947	790,384	34,164	9,605	0
19	Meters	370	0	None	0	0	0	0	0	0
20	Street Lighting	373	820,118	StLgt-Cost	0	0	0	0	321,975	498,143
21	Total DISTRIBUTION Plant	360-373	9,810,703		7,475,976	3,614	1,422,214	57,503	338,805	512,591
22										
23	**E. GENERAL PLANT**									
24	General Plant	389	596,000	SecC-Lab	420,642	209	79,040	2,920	36,425	56,765
25	Communication Equip	398	59,605	SecC-Lab	42,067	21	7,905	292	3,643	5,677
26	Total GENERAL Plant	389-399	655,605		462,709	229	86,944	3,212	40,068	62,442
27										
28	**TOTAL UTILITY PLANT**		10,466,308		7,938,686	3,843	1,509,159	60,715	378,873	575,033
29										

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Citizens Electric Company of Lewisburg
Embedded Cost of Service Study (ECOSS) (R)
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Line	Account	No.	Balance	Allocator	RS	SH	GLP-1	GLP-3	MBL	OL
30	**II. DEPRECIATION RESERVE**									
31	Intangible Plant	108.3	0	SecC-IntPt	0	0	0	0	0	0
32	Transmission Plant	108.5	0	None	0	0	0	0	0	0
33	Station Equipment	108.5	0	None	0	0	0	0	0	0
34	Poles, Towers and Fixtures	108.6	718,147	Avg-Cust	597,567	296	112,285	4,148	1,284	2,568
35	OH Conductors and Devices	108.6	550,814	Avg-Cust	458,330	227	86,122	3,181	985	1,969
36	UG Conduits and Conductors	108.6	750,851	Avg-Cust	624,780	310	117,398	4,337	1,342	2,685
37	Line Transformers	108.6	0	Avg-Cust-Sec	0	0	0	0	0	0
38	Services	108.6	2,261,922	Services_Cost	1,879,827	890	361,203	15,613	4,390	0
39	Meters	108.6	0	None	0	0	0	0	0	0
40	Street Lighting	108.6	170,989	StLgt-Cost	0	0	0	0	67,129	103,859
41	General Plant	108.6	445,913	SecC-Lab	314,714	156	59,136	2,184	27,253	42,470
35	Total DEPRECIATION RESERVE	108	4,898,636		3,875,219	1,879	736,142	29,463	102,382	153,551
42										
43	**III. OTHER RATE BASE ITEMS**									
44	Cash Working Capital	131	71,699	SecC-OpExp	53,144	26	10,002	374	3,187	4,966
45	CWIP	131	0	SecC-Pt	0	0	0	0	0	0
45	Materials & Supplies	255	48,939	SecC-OpExp	36,274	18	6,827	255	2,175	3,389
46	Customer Deposits		0	CustDeposits	0	0	0	0	0	0
47	ADIT / EDIT	154	(99,623)	SecC-Pt	(75,564)	(37)	(14,365)	(578)	(3,606)	(5,473)
48	Accrued Pension / OPEB	182	(36,874)	SecC-Lab	(26,025)	(13)	(4,890)	(181)	(2,254)	(3,512)
49	Total OTHER RATE BASE ITEMS	131-283	(15,860)		(12,170)	(5)	(2,427)	(129)	(498)	(630)
50										
51	**TOTAL RATE BASE**		5,551,812		4,051,297	1,959	770,589	31,122	275,993	420,852
52										

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Citizens Electric Company of Lewisburg
Embedded Cost of Service Study (ECOSS) (R)
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Line	Account	No.	Balance	Allocator	RS	SH	GLP-1	GLP-3	MBL	OL
53	**I. OPERATING AND MAINTENANCE EXPENSES**									
54	**B. TRANSMISSION EXPENSE**									
55	Transmission Expense		0	None	0	0	0	0	0	0
56	Total TRANSMISSION Expense		0		0	0	0	0	0	0
57										
58	**C. DISTRIBUTION OPER. & MAINT. E**									
59	Ops Supv & Engineering	580	27,240	SecC-Lab	19,225	10	3,612	133	1,665	2,594
60	Station Expenses	582	0	None	0	0	0	0	0	0
61	OH Line Expenses	583	46,156	Avg-Cust	38,406	19	7,217	267	83	165
62	Street Lighting Expenses	585	5,137	StLgt-Cost	0	0	0	0	2,017	3,120
63	Meter Expenses	586	0	None	0	0	0	0	0	0
64	Customer Installation Expenses	587	0	None	0	0	0	0	0	0
65	Misc. Distribution Expenses	588	89,982	Avg-Cust	74,874	37	14,069	520	161	322
66	Rents	589	167	Avg-Cust	139	0	26	1	0	1
67	Maint Supv & Engineering	590	0	SecC-Lab	0	0	0	0	0	0
68	Maint of Station Equip	592	0	None	0	0	0	0	0	0
69	Maint of OH Lines	593	157,653	Avg-Cust	131,183	65	24,650	911	282	564
70	Maint of UG Lines	594	4,302	Avg-Cust	3,580	2	673	25	8	15
71	Maint of Line Transformers	595	0	Avg-Cust-Sec	0	0	0	0	0	0
72	Maint of Lighting	596	24,187	StLgt-Cost	0	0	0	0	9,496	14,691
73	Maint of Misc. Plant	599	0	SecC-Pt	0	0	0	0	0	0
74	Total DISTR. OPER. & MAINT. EXP.	500-599	354,824		267,407	133	50,246	1,856	13,710	21,472
75	Distribution Expense		354,824		267,407	133	50,246	1,856	13,710	21,472
76	**D. CUSTOMER ACCOUNTS AND SERVICE**									
77	Supervision	901	0	None	0	0	0	0	0	0
78	Meter Reading Exp	902	0	None	0	0	0	0	0	0
79	Customer Records & Coll	903	0	None	0	0	0	0	0	0
80	Uncollectible Accounts	904	0	None	0	0	0	0	0	0
81	Subtotal - Customer Accounts Exp.	901-905	0		0	0	0	0	0	0
82	Total CUST. ACCT. & SERV. EXP.	901-919	0		0	0	0	0	0	0
83										

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Citizens Electric Company of Lewisburg
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Line	Account	No.	Balance	Allocator	RS	SH	GLP-1	GLP-3	MBL	OL
84	**E. ADMINISTRATIVE AND GENERAL**									
85	Administrative & General Salaries	920	123,230	SecC-Lab	86,973	43	16,342	604	7,531	11,737
86	Office Supplies & Expenses	921	21,064	SecC-Lab	14,866	7	2,793	103	1,287	2,006
87	Outside Services Employed	923	8,212	SecC-LabPt	6,012	3	1,137	44	400	617
88	Property Insurance	924	3,273	SecC-Pt	2,482	1	472	19	118	180
89	Injuries and Damages	925	8,554	SecC-Pt	6,488	3	1,233	50	310	470
90	Employee Pensions & Benefits	926	1,219	SecC-Lab	860	0	162	6	75	116
91	Regulatory Commission Expense	928	0	SecC-Pt	0	0	0	0	0	0
92	Miscellaneous General Expense	930	24,611	SecC-LabPt	18,019	9	3,406	132	1,198	1,848
89	Maint General Property	932	48,961	SecC-Pt	37,137	18	7,060	284	1,772	2,690
93	Total A&G Expense	920-932	239,124		172,838	85	32,605	1,241	12,691	19,664
94										
95	TOTAL OPERATING EXPENSES		593,948		440,245	218	82,852	3,097	26,401	41,136
96										
97	**II. DEPRECIATION EXPENSE**									
98	Intangible Plant		0	SecC-IntPt	0	0	0	0	0	0
99	Station Equipment	361/362	0	None	0	0	0	0	0	0
100	Poles, Towers and Fixtures	364	39,140	Avg-Cust	32,568	16	6,120	226	70	140
101	OH Conductors and Devices	364	72,490	Avg-Cust	60,318	30	11,334	419	130	259
102	UG Conduits and Conductors	364	45,982	Avg-Cust	38,261	19	7,189	266	82	164
103	Line Transformers	364	0	Avg-Cust-Sec	0	0	0	0	0	0
104	Services	364	191,856	Services_Cost	159,447	75	30,637	1,324	372	0
105	Meters	364	0	None	0	0	0	0	0	0
106	Street Lighting	364	45,208	StLgt-Cost	0	0	0	0	17,749	27,460
107	General Plant	364	31,880	SecC-Lab	22,500	11	4,228	156	1,948	3,036
108	Total DEPRECIATION Expense	403	426,555		313,094	152	59,508	2,391	20,351	31,060
109										
110	**III. TAXES and OTHER**									
111	**A. GENERAL TAXES**									
112	Payroll related	408	0	SecC-Lab	0	0	0	0	0	0
113	PURTA, Real estate	408.16	4,457	SecC-Pt	3,381	2	643	26	161	245
114	PUC Assessment		20,348	RateBase	13,566	25	3,096	2,801	334	525
115	PA Use Tax	408	2,250	SecC-Pt	1,707	1	324	13	81	124
116	Subtotal - General Taxes		27,055		18,654	27	4,063	2,840	577	894
117										
118	**B. GROSS RECEIPTS TAX**									
119	Gross Receipts tax		78,125	Dist_Rev	50,367	113	14,091	11,730	337	1,487
120	Subtotal- Gross Receipts tax		78,125		50,367	113	14,091	11,730	337	1,487
121										

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Citizens Electric Company of Lewisburg
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Class Allocation- Secondary Customer

Line	Account	No.	Balance	Allocator	RS	SH	GLP-1	GLP-3	MBL	OL
122	**B. FEDERAL / STATE INCOME TAXES**									
123	State Income Tax Expense		(6,351)	PreTax-Sta	(4,161)	(9)	(984)	(1,012)	(71)	(114)
124	Federal Income Tax Expense		348	PreTax-Fed	32	1	201	92	0	21
125	Subtotal - Federal / State Income Taxes	409-411	(6,003)		(4,130)	(8)	(783)	(920)	(71)	(92)
126	Total TAXES	408-411	99,177		64,892	132	17,371	13,651	844	2,288
127										
128	**TOTAL EXPENSES**		1,119,681		818,231	502	159,731	19,139	47,596	74,484
129										
130	**IV. OPERATING REVENUES at Present Rates**									
131	Distribution Revenue		1,331,834	Dist_Rev	858,632	1,923	240,217	199,967	5,752	25,344
132	Forfeited Discounts		0	Write-Offs	0	0	0	0	0	0
133	Rent For Electric Property		11,975	Avg-Cust	9,964	5	1,872	69	21	43
134	Other Electric Revenues		3,088	Dist_Rev	1,991	4	557	464	13	59
135	Total REVENUES		1,346,896		870,587	1,932	242,646	200,500	5,787	25,445
136										
137	TOTAL EXPENSES		1,119,681		818,231	502	159,731	19,139	47,596	74,484
138	**V. NET INCOME at Present Rates**		227,215		52,357	1,430	82,915	181,361	(41,809)	(49,038)
139										
140	**SUMMARY REPORT**									
141	OPERATING REVENUES									
142	Utility Revenues	440-446	1,331,834		858,632	1,923	240,217	199,967	5,752	25,344
143	Other Operating Revenues	450-456	15,062		11,955	9	2,429	533	35	102
144	Total Operating Revenues		1,346,896		870,587	1,932	242,646	200,500	5,787	25,445
145										
146	OPERATING EXPENSES									
147	Distribution / Transmission	580-599	354,824		267,407	133	50,246	1,856	13,710	21,472
148	Customer Acctg & Service	901-919	0		0	0	0	0	0	0
149	Admin & General	920-932	239,124		172,838	85	32,605	1,241	12,691	19,664
150	Total Operating Expenses		593,948		440,245	218	82,852	3,097	26,401	41,136
151										
152	Depreciation Expense	403	426,555		313,094	152	59,508	2,391	20,351	31,060
153	Taxes Other Than Income Tax / Other	408	105,181		69,021	140	18,154	14,570	915	2,380
154	INCOME BEFORE INCOME TAXES		221,212		48,227	1,423	82,132	180,441	(41,880)	(49,131)
155	Income Taxes	409-411	(6,003)		(4,130)	(8)	(783)	(920)	(71)	(92)
156	**NET INCOME**		227,215		52,357	1,430	82,915	181,361	(41,809)	(49,038)
157										
158	**RATE BASE**		5,551,812		4,051,297	1,959	770,589	31,122	275,993	420,852
159	Return on Rate Base		4.09%							
160										

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Line	Account	No.	Balance	Allocator	RS	SH	GLP-1	GLP-3	MBL	OL
161	**REVENUE REQUIREMENTS**									
162	Target Rate of Return		8.4900%		8.4900%	8.4900%	8.4900%	8.4900%	8.4900%	8.4900%
163										
164	Rate Base		5,551,812		4,051,297	1,959	770,589	31,122	275,993	420,852
165										
166	Operating expenses		573,600		426,678	193	79,756	296	26,067	40,610
167	Uncollectibles expense		0	None	0	0	0	0	0	0
168	Depreciation expense		426,555		313,094	152	59,508	2,391	20,351	31,060
169	Regulatory Commission Expenses		20,348	SecC-Pt	13,566	25	3,096	2,801	334	525
170	General taxes / Other		27,055		18,654	27	4,063	2,840	577	894
171	Subtotal- Operating Costs to recover		1,047,559		771,993	397	146,423	8,328	47,330	73,089
172										
173	Target Return on Rate Base- After taxes		471,349		343,955	166	65,423	2,642	23,432	35,730
174										
175	Income taxes to recover		130,798	27.75%	95,446	46	18,155	733	6,502	9,915
176										
177	Subtotal- Rev Req before GRT		1,649,706		1,211,394	609	230,001	11,704	77,264	118,735
178	GRT needed		101,997	6.24%	74,841	37	14,200	697	4,819	7,402
179	**TOTAL REVENUE REQUIREMENT**		1,751,702		1,286,236	647	244,200	12,401	82,082	126,137
180										
181	Revenue at Present rates		1,346,896		870,587	1,932	242,646	200,500	5,787	25,445
182	Revenue Excess (Deficiency)		(404,806)		(415,648)	1,285	(1,554)	188,099	(76,296)	(100,692)

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FPFTY Ending December 31, 2026
Class Allocation- Billing Customer

Line	Account	No.	Balance	Allocator	RS	SH	GLP-1	GLP-3	MBL	OL
1	**I. ELECTRIC PLANT IN SERVICE**									
2	INTANGIBLE PLANT									
3	Organization	302	0	Bill-Pt	0	0	0	0	0	0
4	EDI Software	303	0	Avg-Cust	0	0	0	0	0	0
5	Total INTANGIBLE Plant		0		0	0	0	0	0	0
6										
7	**C. TRANSMISSION PLANT**									
8	Transmission Plant	361	0	None	0	0	0	0	0	0
9	Total TRANSMISSION Plant	350-359	0		0	0	0	0	0	0
10										
11	**D. DISTRIBUTION PLANT**									
12	Land and Land Rights	360	0	None	0	0	0	0	0	0
13	Station Equipment	362	0	None	0	0	0	0	0	0
14	Poles, Towers and Fixtures	364	0	None	0	0	0	0	0	0
15	OH Conductors and Devices	365	0	None	0	0	0	0	0	0
16	UG Conduits and Conductors	366	0	None	0	0	0	0	0	0
17	Line Transformers	368	0	None	0	0	0	0	0	0
18	Services	369	0	None	0	0	0	0	0	0
19	Meters	370	1,798,757	Meter_Cost	1,277,542	611	421,810	98,793	0	0
20	Street Lighting	373	0	StLgt-Cost	0	0	0	0	0	0
21	Total DISTRIBUTION Plant	360-373	1,798,757		1,277,542	611	421,810	98,793	0	0
22										
23	**E. GENERAL PLANT**									
24	General Plant	389	1,381,516	Bill-Lab	1,132,159	560	227,159	14,994	2,215	4,429
25	Communication Equip	398	138,163	Bill-Lab	113,225	56	22,718	1,500	221	443
26	Total GENERAL Plant	389-399	1,519,678		1,245,384	615	249,877	16,494	2,436	4,872
27										
28	**TOTAL UTILITY PLANT**		3,318,436		2,522,926	1,227	671,687	115,287	2,436	4,872
29										

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Class Allocation- Billing Customer
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Citizens Electric Company of Lewisburg
Embedded Cost of Service Study (ECOSS) (R)
FPFTY Ending December 31, 2026
Class Allocation- Billing Customer

Line	Account	No.	Balance	Allocator	RS	SH	GLP-1	GLP-3	MBL	OL
30	**II. DEPRECIATION RESERVE**									
31	Intangible Plant	108.3	0	Avg-Cust	0	0	0	0	0	0
32	Transmission Plant	108.5	0	None	0	0	0	0	0	0
33	Station Equipment	108.5	0	None	0	0	0	0	0	0
34	Poles, Towers and Fixtures	108.6	0	None	0	0	0	0	0	0
35	OH Conductors and Devices	108.6	0	None	0	0	0	0	0	0
36	UG Conduits and Conductors	108.6	0	None	0	0	0	0	0	0
37	Line Transformers	108.6	0	None	0	0	0	0	0	0
38	Services	108.6	0	None	0	0	0	0	0	0
39	Meters	108.6	102,702	Meter_Cost	72,943	35	24,084	5,641	0	0
40	Street Lighting	108.6	0	StLgt-Cost	0	0	0	0	0	0
41	General Plant	108.6	1,033,618	Bill-Lab	847,055	419	169,955	11,218	1,657	3,314
35	Total DEPRECIATION RESERVE	108	1,136,320		919,998	454	194,039	16,859	1,657	3,314
42										
43	**III. OTHER RATE BASE ITEMS**									
44	Cash Working Capital	131	141,708	Bill-OpExp	112,917	72	23,553	3,948	424	794
45	CWIP	131	0	Bill-Pt	0	0	0	0	0	0
45	Materials & Supplies	255	96,724	Bill-OpExp	77,072	49	16,076	2,694	289	542
46	Customer Deposits		(189,068)	CustDeposits	(31,294)	(46)	(83,483)	(74,245)	0	0
47	ADIT / EDIT	154	(31,586)	Bill-Pt	(24,014)	(12)	(6,393)	(1,097)	(23)	(46)
48	Accrued Pension / OPEB	182	(85,474)	Bill-Lab	(70,046)	(35)	(14,054)	(928)	(137)	(274)
49	Total OTHER RATE BASE ITEMS	131-283	(67,697)		64,635	28	(64,301)	(69,628)	553	1,016
50										
51	**TOTAL RATE BASE**		2,114,419		1,667,563	801	413,348	28,800	1,333	2,574
52										

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Citizens Electric Company of Lewisburg
Embedded Cost of Service Study (ECOSS) (R)
FPFTY Ending December 31, 2026
Class Allocation- Billing Customer

Line	Account	No.	Balance	Allocator	RS	SH	GLP-1	GLP-3	MBL	OL
53	**I. OPERATING AND MAINTENANCE EXPENSES**									
54	**B. TRANSMISSION EXPENSE**									
55	Transmission Expense		0	None	0	0	0	0	0	0
56	Total TRANSMISSION Expense		0		0	0	0	0	0	0
57										
58	**C. DISTRIBUTION OPER. & MAINT. E**									
59	Ops Supv & Engineering	580	20,172	Bill-DxLab	15,504	8	3,976	633	17	35
60	Station Expenses	582	0	None	0	0	0	0	0	0
61	OH Line Expenses	583	0	None	0	0	0	0	0	0
62	Street Lighting Expenses	585	0	StLgt-Cost	0	0	0	0	0	0
63	Meter Expenses	586	50,712	Meter_Cost	36,018	17	11,892	2,785	0	0
64	Customer Installation Expenses	587	56,416	Avg-Cust	46,944	23	8,821	326	101	202
65	Misc. Distribution Expenses	588	0	Avg-Cust	0	0	0	0	0	0
66	Rents	589	31	Bill-Pt	23	0	6	1	0	0
67	Maint Supv & Engineering	590	0	None	0	0	0	0	0	0
68	Maint of Station Equip	592	0	None	0	0	0	0	0	0
69	Maint of OH Lines	593	0	None	0	0	0	0	0	0
70	Maint of UG Lines	594	0	None	0	0	0	0	0	0
71	Maint of Line Transformers	595	0	None	0	0	0	0	0	0
72	Maint of Lighting	596	0	StLgt-Cost	0	0	0	0	0	0
73	Maint of Misc. Plant	599	0	Avg-Cust	0	0	0	0	0	0
74	Total DISTR. OPER. & MAINT. EXP.	500-599	127,331		98,488	48	24,695	3,745	118	236
75	Distribution Expense		127,331		98,488	48	24,695	3,745	118	236
76	**D. CUSTOMER ACCOUNTS AND SERVICE**									
77	Supervision	901	0	Avg-Cust	0	0	0	0	0	0
78	Meter Reading Exp	902	26,000	Meter_Cost	18,466	9	6,097	1,428	0	0
79	Customer Records & Coll	903	492,479	Avg-Cust	409,789	203	77,001	2,844	880	1,761
80	Uncollectible Accounts	904	30,900	Write-Offs	19,921	45	5,573	4,639	133	588
81	Subtotal - Customer Accounts Exp.	901-905	549,379		448,177	257	88,671	8,912	1,014	2,349
82	Total CUST. ACCT. & SERV. EXP.	901-919	549,379		448,177	257	88,671	8,912	1,014	2,349
83										

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Citizens Electric Company of Lewisburg
Embedded Cost of Service Study (ECOSS) (R)
FPFTY Ending December 31, 2026
Class Allocation- Billing Customer

Line	Account	No.	Balance	Allocator	RS	SH	GLP-1	GLP-3	MBL	OL
84	**E. ADMINISTRATIVE AND GENERAL**									
85	Administrative & General Salaries	920	285,645	Bill-Lab	234,087	116	46,968	3,100	458	916
86	Office Supplies & Expenses	921	48,826	Bill-Lab	40,013	20	8,028	530	78	157
87	Outside Services Employed	923	7,938	Bill-LabPt	6,270	3	1,456	181	9	19
88	Property Insurance	924	1,038	Bill-Pt	789	0	210	36	1	2
89	Injuries and Damages	925	2,712	Bill-Pt	2,062	1	549	94	2	4
90	Employee Pensions & Benefits	926	2,826	Bill-Lab	2,316	1	465	31	5	9
91	Regulatory Commission Expense	928	108,889	RateBase	72,597	134	16,567	14,991	1,789	2,811
92	Miscellaneous General Expense	930	23,792	Bill-LabPt	18,793	9	4,364	542	28	56
89	Maint General Property	932	15,524	Bill-Pt	11,802	6	3,142	539	11	23
93	Total A&G Expense	920-932	497,189		388,730	290	81,748	20,045	2,381	3,995
94										
95	TOTAL OPERATING EXPENSES		1,173,899		935,395	594	195,114	32,702	3,513	6,580
96										
97	**II. DEPRECIATION EXPENSE**									
98	Intangible Plant		0	Avg-Cust	0	0	0	0	0	0
99	Station Equipment	361/362	0	None	0	0	0	0	0	0
100	Poles, Towers and Fixtures	364	0	None	0	0	0	0	0	0
101	OH Conductors and Devices	364	0	None	0	0	0	0	0	0
102	UG Conduits and Conductors	364	0	None	0	0	0	0	0	0
103	Line Transformers	364	0	None	0	0	0	0	0	0
104	Services	364	0	None	0	0	0	0	0	0
105	Meters	364	70,794	Meter_Cost	50,280	24	16,601	3,888	0	0
106	Street Lighting	364	0	StLgt-Cost	0	0	0	0	0	0
107	General Plant	364	73,897	Bill-Lab	60,559	30	12,151	802	118	237
108	Total DEPRECIATION Expense	403	144,691		110,839	54	28,752	4,690	118	237
109										
110	**III. TAXES and OTHER**									
111	**A. GENERAL TAXES**									
112	Payroll related	408	0	None	0	0	0	0	0	0
113	PURTA, Real estate	408.16	1,413	Bill-Pt	1,074	1	286	49	1	2
114	PUC Assessment		7,750	RateBase	5,167	10	1,179	1,067	127	200
115	PA Use Tax	408	713	Bill-Pt	542	0	144	25	1	1
116	Subtotal - General Taxes		9,876		6,784	10	1,609	1,141	129	203
117										
118	**B. GROSS RECEIPTS TAX**									
119	Gross Receipts tax		78,419	Dist_Rev	50,557	113	14,144	11,774	339	1,492
120	Subtotal- Gross Receipts tax		78,419		50,557	113	14,144	11,774	339	1,492
121										

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Citizens Electric Company of Lewisburg
Embedded Cost of Service Study (ECOSS) (R)
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Class Allocation- Billing Customer

Line	Account	No.	Balance	Allocator	RS	SH	GLP-1	GLP-3	MBL	OL
122	**B. FEDERAL / STATE INCOME TAXES**									
123	State Income Tax Expense		0	PreTax-Sta	0	0	0	0	0	0
124	Federal Income Tax Expense		0	PreTax-Fed	0	0	0	0	0	0
125	Subtotal - Federal / State Income Taxes	409-411	0		0	0	0	0	0	0
126	Total TAXES	408-411	88,295		57,340	123	15,754	12,915	468	1,695
127										
128	**TOTAL EXPENSES**		1,406,885		1,103,574	772	239,620	50,307	4,099	8,512
129										
130	**IV. OPERATING REVENUES at Present Rates**									
131	Distribution Revenue		1,301,745	Dist_Rev	839,234	1,879	234,790	195,449	5,622	24,771
132	Forfeited Discounts		35,091	Write-Offs	22,623	51	6,329	5,269	152	668
133	Rent For Electric Property		0	None	0	0	0	0	0	0
134	Other Electric Revenues		3,018	Dist_Rev	1,946	4	544	453	13	57
135	Total REVENUES		1,339,855		863,803	1,934	241,663	201,171	5,786	25,496
136										
137	TOTAL EXPENSES		1,406,885		1,103,574	772	239,620	50,307	4,099	8,512
138	**V. NET INCOME at Present Rates**		(67,030)		(239,771)	1,162	2,044	150,864	1,687	16,984
139										
140	**SUMMARY REPORT**									
141	OPERATING REVENUES									
142	Utility Revenues	440-446	1,336,837		861,858	1,930	241,119	200,718	5,773	25,439
143	Other Operating Revenues	450-456	3,018		1,946	4	544	453	13	57
144	Total Operating Revenues		1,339,855		863,803	1,934	241,663	201,171	5,786	25,496
145										
146	OPERATING EXPENSES									
147	Distribution / Transmission	580-599	127,331		98,488	48	24,695	3,745	118	236
148	Customer Acctg & Service	901-919	549,379		448,177	257	88,671	8,912	1,014	2,349
149	Admin & General	920-932	497,189		388,730	290	81,748	20,045	2,381	3,995
150	Total Operating Expenses		1,173,899		935,395	594	195,114	32,702	3,513	6,580
151										
152	Depreciation Expense	403	144,691		110,839	54	28,752	4,690	118	237
153	Taxes Other Than Income Tax / Other	408	88,295		57,340	123	15,754	12,915	468	1,695
154	INCOME BEFORE INCOME TAXES		(67,030)		(239,771)	1,162	2,044	150,864	1,687	16,984
155	Income Taxes	409-411	0		0	0	0	0	0	0
156	**NET INCOME**		(67,030)		(239,771)	1,162	2,044	150,864	1,687	16,984
157										
158	**RATE BASE**		2,114,419		1,667,563	801	413,348	28,800	1,333	2,574
159	Return on Rate Base		-3.17%							
160										

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Citizens Electric Company of Lewisburg
Embedded Cost of Service Study (ECOSS) (R)
FPFTY Ending December 31, 2026
Class Allocation- Billing Customer

Line	Account	No.	Balance	Allocator	RS	SH	GLP-1	GLP-3	MBL	OL
161	**REVENUE REQUIREMENTS**									
162	Target Rate of Return		8.4900%		8.4900%	8.4900%	8.4900%	8.4900%	8.4900%	8.4900%
163										
164	Rate Base		2,114,419		1,667,563	801	413,348	28,800	1,333	2,574
165										
166	Operating expenses		1,135,249		910,307	540	188,362	26,996	3,253	5,792
167	Uncollectibles expense		30,900	Write-Offs	19,921	45	5,573	4,639	133	588
168	Depreciation expense		144,691		110,839	54	28,752	4,690	118	237
169	Regulatory Commission Expenses		7,750	Bill-Pt	5,167	10	1,179	1,067	127	200
170	General taxes / Other		9,876		6,784	10	1,609	1,141	129	203
171	Subtotal- Operating Costs to recover		1,328,466		1,053,018	659	225,476	38,533	3,761	7,020
172										
173	Target Return on Rate Base- After taxes		179,514		141,576	68	35,093	2,445	113	219
174										
175	Income taxes to recover		49,815	27.75%	39,287	19	9,738	679	31	61
176										
177	Subtotal- Rev Req before GRT		1,557,795		1,233,881	745	270,307	41,657	3,905	7,299
178	GRT needed		97,013	6.24%	76,869	46	16,832	2,571	243	452
179	**TOTAL REVENUE REQUIREMENT**		1,654,808		1,310,750	792	287,139	44,228	4,148	7,751
180										
181	Revenue at Present rates		1,339,855		863,803	1,934	241,663	201,171	5,786	25,496
182	Revenue Excess (Deficiency)		(314,953)		(446,947)	1,143	(45,476)	156,943	1,638	17,745

Assigned
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Citizens Electric Company of Lewisburg
Embedded Cost of Service Study (ECOSS) (R)
FPFTY Ending December 31, 2026
Allocator Assignments

Line	Account	No.	Balance	Function	Classify	Class Allocation			
				Allocator	Secondary	PrimDem	SecnDem	SecnCus	BillCus
1	**I. ELECTRIC PLANT IN SERVICE**								
2	INTANGIBLE PLANT								
3	Organization	302	0	-	-	-	-	-	-
4	EDI Software	303	0	-	-	-	-	-	-
5	Total INTANGIBLE Plant		0						
6									
7	**C. TRANSMISSION PLANT**								
8	Transmission Plant	361	0	-	-	-	-	-	-
9	Total TRANSMISSION Plant	350-359	0						
10									
11	**D. DISTRIBUTION PLANT**								
12	Land and Land Rights	360	21,453	Prim	-	NCP-Prim	-	-	-
13	Station Equipment	362	776,412	Prim	-	NCP-Prim	-	-	-
14	Poles, Towers and Fixtures	364	4,934,235	OH_Cond	PTF-Sec-Z	NCP-Prim	NCP-Sec	Avg-Cust	-
15	OH Conductors and Devices	365	9,866,317	OH_Cond	OH-Sec-Z	NCP-Prim	NCP-Sec	Avg-Cust	-
16	UG Conduits and Conductors	366	4,063,329	UG_Cond	UG-Sec-Z	NCP-Prim	NCP-Sec	Avg-Cust	-
17	Line Transformers	368	3,430,881	Trans	Demand	-	NCP-Ltr	-	-
18	Services	369	4,949,542	Sec	Customer	-	-	Services_Cost	-
19	Meters	370	1,798,757	Bill	-	-	-	-	Meter_Cost
20	Street Lighting	373	820,118	Sec	Customer	-	-	StLgt-Cost	-
21	Total DISTRIBUTION Plant	360-373	30,661,045						
22									
23	**E. GENERAL PLANT**								
24	General Plant	389	4,280,032	Labor	Sec-Lab	PriD-Lab	SecD-Lab	SecC-Lab	Bill-Lab
25	Communication Equip	398	428,037	Labor	Sec-Lab	PriD-Lab	SecD-Lab	SecC-Lab	Bill-Lab
26	Total GENERAL Plant	389-399	4,708,069						
27									
28	**TOTAL UTILITY PLANT**		35,369,114						
29									

Assigned
Allocator Assignments
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Citizens Electric Company of Lewisburg
Embedded Cost of Service Study (ECOSS) (R)
FPFTY Ending December 31, 2026
Allocator Assignments

Line	Account	No.	Balance	Function	Classify	Class Allocation			
				Allocator	Secondary	PrimDem	SecnDem	SecnCus	BillCus
30	**II. DEPRECIATION RESERVE**								
31	Intangible Plant	108.3	0	-	-	-	-	-	-
32	Transmission Plant	108.5	0	-	-	-	-	-	-
33	Station Equipment	108.5	763,782	Prim	-	NCP-Prim	-	-	-
34	Poles, Towers and Fixtures	108.6	3,612,745	OH_Cond	PTF-Sec-Z	NCP-Prim	NCP-Sec	Avg-Cust	-
35	OH Conductors and Devices	108.6	2,888,827	OH_Cond	OH-Sec-Z	NCP-Prim	NCP-Sec	Avg-Cust	-
36	UG Conduits and Conductors	108.6	2,587,766	UG_Cond	UG-Sec-Z	NCP-Prim	NCP-Sec	Avg-Cust	-
37	Line Transformers	108.6	2,598,828	Trans	Demand	-	NCP-Ltr	-	-
38	Services	108.6	2,261,922	Sec	Customer	-	-	Services_Cost	-
39	Meters	108.6	102,702	Bill	-	-	-	-	Meter_Cost
40	Street Lighting	108.6	170,989	Sec	Customer	-	-	StLgt-Cost	-
41	General Plant	108.6	3,202,220	GenPtxL	Sec-GenPt	PriD-Lab	SecD-Lab	SecC-Lab	Bill-Lab
35	Total DEPRECIATION RESERVE	108	4,376,527						
42									
43	**III. OTHER RATE BASE ITEMS**								
44	Cash Working Capital	131	481,732	OpExp_Dist	Sec-OpExp	PriD-OpExp	SecD-OpExp	SecC-OpExp	Bill-OpExp
45	CWIP	131	0	-	-	-	-	-	-
45	Materials & Supplies	255	328,809	OpExp_Dist	Sec-OpExp	PriD-OpExp	SecD-OpExp	SecC-OpExp	Bill-OpExp
46	Customer Deposits		(189,068)	Bill	-	-	-	-	CustDeposits
47	ADIT / EDIT	154	(336,658)	Plant	Sec-Pt	PriD-Pt	SecD-Pt	SecC-Pt	Bill-Pt
48	Accrued Pension / OPEB	182	(264,804)	Labor	Sec-Lab	PriD-Lab	SecD-Lab	SecC-Lab	Bill-Lab
49	Total OTHER RATE BASE ITEMS	131-283	20,011						
50									
51	**TOTAL RATE BASE**		31,012,597						
52									
53	**I. OPERATING AND MAINTENANCE EXPENSES**								
54	B. TRANSMISSION EXPENSE								
55	Transmission Expense								
56	Total TRANSMISSION Expense								
57									

Assigned
Allocator Assignments
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Citizens Electric Company of Lewisburg
Embedded Cost of Service Study (ECOSS) (R)
FPFTY Ending December 31, 2026
Allocator Assignments

Line	Account	No.	Balance	Function	Classify	Class Allocation			
				Allocator	Secondary	PrimDem	SecnDem	SecnCus	BillCus
58	**C. DISTRIBUTION OPER. & MAINT. EXPENSE**								
59	Ops Supv & Engineering	580	154,958	D-Labor-Op	Sec-Lab	PriD-Lab	SecD-Lab	SecC-Lab	Bill-DxLab
60	Station Expenses	582	14,046	Prim	-	NCP-Prim	-	-	-
61	OH Line Expenses	583	242,072	OH_Cond	OH-Sec-Z	NCP-Prim	NCP-Sec	Avg-Cust	-
62	Street Lighting Expenses	585	5,137	Sec	Customer	-	-	StLgt-Cost	-
63	Meter Expenses	586	50,712	Bill	-	-	-	-	Meter_Cost
64	Customer Installation Expenses	587	56,416	Bill	-	-	-	-	Avg-Cust
65	Misc. Distribution Expenses	588	495,254	OH_UG	Sec-OH_UG	NCP-Prim	NCP-Sec	Avg-Cust	-
66	Rents	589	525	DistPt	Sec-Pt	NCP-Prim	NCP-Sec	Avg-Cust	Bill-Pt
67	Maint Supv & Engineering	590	0	-	-	-	-	-	-
68	Maint of Station Equip	592	17,209	Prim	-	NCP-Prim	-	-	-
69	Maint of OH Lines	593	826,836	OH_Cond	OH-Sec-Z	NCP-Prim	NCP-Sec	Avg-Cust	-
70	Maint of UG Lines	594	14,827	UG_Cond	UG-Sec-Z	NCP-Prim	NCP-Sec	Avg-Cust	-
71	Maint of Line Transformers	595	27,468	Trans	Demand	-	NCP-Ltr	-	-
72	Maint of Lighting	596	24,187	Sec	Customer	-	-	StLgt-Cost	-
73	Maint of Misc. Plant	599	0	-	-	-	-	-	-
74	Total DISTR. OPER. & MAINT. EX	500-599	1,929,647						
75	Distribution Expense								
76	**D. CUSTOMER ACCOUNTS AND SERVICE**								
77	Supervision	901	0	-	-	-	-	-	-
78	Meter Reading Exp	902	26,000	Bill	-	-	-	-	Meter_Cost
79	Customer Records & Coll	903	492,479	Bill	-	-	-	-	Avg-Cust
80	Uncollectible Accounts	904	30,900	Bill	-	-	-	-	Write-Offs
81	Subtotal - Customer Accounts Exp.	901-905	549,379						
82	Total CUST. ACCT. & SERV. EXP.	901-919	549,379						
83									

Assigned
Allocator Assignments
Fac
E-5A (R)

Citizens Electric Company of Lewisburg
Embedded Cost of Service Study (ECOSS) (R)
FPFTY Ending December 31, 2026
Allocator Assignments

Line	Account	No.	Balance	Function	Classify	Class Allocation			
				Allocator	Secondary	PrimDem	SecnDem	SecnCus	BillCus
84	**E. ADMINISTRATIVE AND GENERAL**								
85	Administrative & General Salaries	920	884,948	Labor	Sec-Lab	PriD-Lab	SecD-Lab	SecC-Lab	Bill-Lab
86	Office Supplies & Expenses	921	151,265	Labor	Sec-Lab	PriD-Lab	SecD-Lab	SecC-Lab	Bill-Lab
87	Outside Services Employed	923	38,110	Labor_Pt	Sec-LabPt	PriD-LabPt	SecD-LabPt	SecC-LabPt	Bill-LabPt
88	Property Insurance	924	11,059	Plant	Sec-Pt	PriD-Pt	SecD-Pt	SecC-Pt	Bill-Pt
89	Injuries and Damages	925	28,907	Plant	Sec-Pt	PriD-Pt	SecD-Pt	SecC-Pt	Bill-Pt
90	Employee Pensions & Benefits	926	8,755	Labor	Sec-Lab	PriD-Lab	SecD-Lab	SecC-Lab	Bill-Lab
91	Regulatory Commission Expense	928	108,889	Bill	-	-	-	-	RateBase
92	Miscellaneous General Expense	930	114,218	Labor_Pt	Sec-LabPt	PriD-LabPt	SecD-LabPt	SecC-LabPt	Bill-LabPt
89	Maint General Property	932	165,455	Plant	Sec-Pt	PriD-Pt	SecD-Pt	SecC-Pt	Bill-Pt
93	Total A&G Expense	920-932	1,511,606						
94									
95	TOTAL OPERATING EXPENSES		3,990,632						
96									
97	**II. DEPRECIATION EXPENSE**								
98	Intangible Plant		0	-	-	-	-	-	-
99	Station Equipment	361/362	4,197	Prim	-	NCP-Prim	-	-	-
100	Poles, Towers and Fixtures	364	196,900	OH_Cond	PTF-Sec-Z	NCP-Prim	NCP-Sec	Avg-Cust	-
101	OH Conductors and Devices	364	380,183	OH_Cond	OH-Sec-Z	NCP-Prim	NCP-Sec	Avg-Cust	-
102	UG Conduits and Conductors	364	158,473	UG_Cond	UG-Sec-Z	NCP-Prim	NCP-Sec	Avg-Cust	-
103	Line Transformers	364	133,449	Trans	Demand	-	NCP-Ltr	-	-
104	Services	364	191,856	Sec	Customer	-	-	Services_Cost	-
105	Meters	364	70,794	Bill	-	-	-	-	Meter_Cost
106	Street Lighting	364	45,208	Sec	Customer	-	-	StLgt-Cost	-
107	General Plant	364	228,938	GenPtxL	Sec-GenPt	PriD-Lab	SecD-Lab	SecC-Lab	Bill-Lab
108	Total DEPRECIATION Expense	403	201,097						
109									
110	**III. TAXES and OTHER**								
111	**A. GENERAL TAXES**								
112	Payroll related	408	0	-	-	-	-	-	-
113	PURTA, Real estate	408.16	15,062	Plant	Sec-Pt	PriD-Pt	SecD-Pt	SecC-Pt	Bill-Pt
114	PUC Assessment		63,038	RateBase	Sec-RB	RateBase	RateBase	RateBase	RateBase
115	PA Use Tax	408	7,604	Plant	Sec-Pt	PriD-Pt	SecD-Pt	SecC-Pt	Bill-Pt
116	Subtotal - General Taxes		85,704						
117									
118	**B. GROSS RECEIPTS TAX**								
119	Gross Receipts tax		357,253	GRT_RevxT	Sec-Rev	Dist_Rev	Dist_Rev	Dist_Rev	Dist_Rev
120	Subtotal- Gross Receipts tax		357,253						
121									

Assigned
Allocator Assignments
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E-5A (R)

Citizens Electric Company of Lewisburg
Embedded Cost of Service Study (ECOSS) (R)
FPFTY Ending December 31, 2026
Allocator Assignments

Line	Account	No.	Balance	Function	Classify	Class Allocation			
				Allocator	Secondary	PrimDem	SecnDem	SecnCus	BillCus
122	**B. FEDERAL / STATE INCOME TAXES**								
123	State Income Tax Expense		(11,138)	StaTax	Sec-StaTax	PreTax-Sta	PreTax-Sta	PreTax-Sta	-
124	Federal Income Tax Expense		609	FedTax	Sec-FedTax	PreTax-Fed	PreTax-Fed	PreTax-Fed	-
125	Subtotal - Federal / State Income Tax	409-411	(10,529)						
126	Total TAXES	408-411	432,429						
127									
128	**TOTAL EXPENSES**		4,624,157						
129									
130	**IV. OPERATING REVENUES at Present Rates**								
131	Distribution Revenue		6,055,143	DistBill_RR-PF	Sec-RetRRPF	Dist_Rev	Dist_Rev	Dist_Rev	Dist_Rev
132	Forfeited Discounts		35,091	Bill	-	-	-	-	Write-Offs
133	Rent For Electric Property		60,240	OH_Cond	PTF-Sec-Z	NCP-Prim	NCP-Sec	Avg-Cust	-
134	Other Electric Revenues		14,038	DistBill_RR-PF	Sec-RetRRPF	Dist_Rev	Dist_Rev	Dist_Rev	Dist_Rev
135	Total REVENUES		6,164,512						
136									
137	TOTAL EXPENSES		4,624,157						
138	**V. NET INCOME at Present Rates**		1,540,356						
139									
140	**SUMMARY REPORT**								
141	OPERATING REVENUES								
142	Utility Revenues	440-446	6,090,234						
143	Other Operating Revenues	450-456	74,278						
144	Total Operating Revenues		6,164,512						
145									
146	OPERATING EXPENSES								
147	Distribution / Transmission	580-599	1,929,647						
148	Customer Acctg & Service	901-919	549,379						
149	Admin & General	920-932	1,511,606						
150	Total Operating Expenses		3,990,632						
151									
152	Depreciation Expense	403	201,097						
153	Taxes Other Than Income Tax / Othe	408	442,957						
154	INCOME BEFORE INCOME TAXE		1,529,827						
155	Income Taxes	409-411	(10,529)						
156	**NET INCOME**		1,540,356						
157									
158	**RATE BASE**		31,012,597						
159	Return on Rate Base		4.97%						
160									

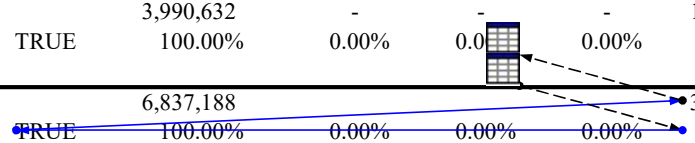
Assigned
Allocator Assignments
Fac
E-5A (R)

Citizens Electric Company of Lewisburg
Embedded Cost of Service Study (ECOSS) (R)
FPFTY Ending December 31, 2026
Allocator Assignments

Line	Account	No.	Balance	Function Allocator	Classify Secondary	Class Allocation PrimDem	SecnDem	SecnCus	BillCus
161	**REVENUE REQUIREMENTS**								
162	Target Rate of Return								
163									
164	Rate Base								
165									
166	Operating expenses								
167	Uncollectibles expense		30,900	BILL	-	-	-	-	Write-Offs
168	Depreciation expense								
169	Regulatory Commission Expenses		63,038	Plant	Sec-Pt	PriD-Pt	SecD-Pt	SecC-Pt	Bill-Pt
170	General taxes / Other								
171	Subtotal- Operating Costs to recover								
172									
173	Target Return on Rate Base- After tax								
174									
175	Income taxes to recover								
176									
177	Subtotal- Rev Req before GRT								
178	GRT needed								
179	**TOTAL REVENUE REQUIREMENT**								

FuncFc **Citizens Electric Company of Lewisburg**
Functio **Embedded Cost of Service Study (ECOSS) (R)**
Fac **FPFTY Ending December 31, 2026**
E-5B (F **Functionalization Factors**

0	Allocator Name	In Use	Total	Supply	Trans-mission	SubTrans-mission	Primary	Secondary	Billing
1	None		0						
2		FALSE	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
3									
4	Tran		1		1				
5		TRUE	100.00%	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%
6									
7	Prim		1				1		
8		TRUE	100.00%	0.00%	0.00%	0.00%	100.00%	0.00%	0.00%
9									
10	Sec		1					1	
11		TRUE	100.00%	0.00%	0.00%	0.00%	0.00%	100.00%	0.00%
12									
13	Bill		1						1
14		TRUE	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%
15									
16	OH_Cond		100.00%	0.00%	0.00%	0.00%	75.37%	24.63%	0.00%
17		TRUE	100.00%	0.00%	0.00%	0.00%	75.37%	24.63%	0.00%
18									
19	UG_Cond		100.00%	0.00%	0.00%	0.00%	49.19%	50.81%	0.00%
20		TRUE	100.00%	0.00%	0.00%	0.00%	49.19%	50.81%	0.00%
21									
22	Trans		100.00%	0.00%	0.00%	0.00%	0.00%	100.00%	0.00%
23		TRUE	100.00%	0.00%	0.00%	0.00%	0.00%	100.00%	0.00%
24									
25	UG_Total		4,063,329	-	-	-	1,998,888	2,064,441	-
26		TRUE	100.00%	0.00%	0.00%	0.00%	49.19%	50.81%	0.00%
27									
28	OpExp_Dist		3,990,632	-	-	-	1,861,936	954,797	1,173,899
29		TRUE	100.00%	0.00%	0.0	0.00%	46.66%	23.93%	29.42%
30									
31	DistBill_RR-PF		6,837,188				3,131,796	2,235,521	1,469,871
32		TRUE	100.00%	0.00%	0.00%	0.00%	45.81%	32.70%	21.50%
33									
34	GRT_RevxT		6,090,234	-	-	-	2,773,578	1,979,820	1,336,837
35		TRUE	100.00%	0.00%	0.00%	0.00%	45.54%	32.51%	21.95%
36									



FuncFc **Citizens Electric Company of Lewisburg**
Functio **Embedded Cost of Service Study (ECOSS) (R)**
Fac **FPFTY Ending December 31, 2026**
E-5B (F **Functionalization Factors**

0	Allocator Name	In Use	Total	Supply	Trans-mission	SubTrans-mission	Primary	Secondary	Billing
37	Labor		680,301	-	-	-	307,436	153,276	219,589
38		TRUE	100.00%	0.00%	0.00%	0.00%	45.19%	22.53%	32.28%
39									
40	D-Labor-Op		268,717	-	-	-	157,307	76,429	34,981
41		TRUE	100.00%	0.00%	0.00%	0.00%	58.54%	28.44%	13.02%
42									
43	D-Labor-Mnt		169,882	-	-	-	111,704	58,178	-
44		TRUE	100.00%	0.00%	0.00%	0.00%	65.75%	34.25%	0.00%
45									
46	Labor_Pt		200.00%	0.00%	0.00%	0.00%	90.65%	67.69%	41.66%
47		TRUE	100.00%	0.00%	0.00%	0.00%	45.33%	33.84%	20.83%
48									
49	IntanPt		-	-	-	-	-	-	-
50		FALSE	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
51									
52	OH_UG		22,294,762	-	-	-	13,153,373	9,141,389	-
53		TRUE	100.00%	0.00%	0.00%	0.00%	59.00%	41.00%	0.00%
54									
55	DistPt		30,661,045	-	-	-	13,951,239	14,911,049	1,798,757
56		TRUE	100.00%	0.00%	0.00%	0.00%	45.50%	48.63%	5.87%
57									
58	GenPtxL		428,037	-	-	-	193,435	96,440	138,163
59		TRUE	100.00%	0.00%	0.00%	0.00%	45.19%	22.53%	32.28%
60									
61	RateBase		17,199,344	-	-	-	7,800,493	7,284,432	2,114,419
62		TRUE	100.00%	0.00%	0.00%	0.00%	45.35%	42.35%	12.29%
63									
64	PreTax		320,926	-	-	-	141,345	246,611	(67,030)
65		TRUE	100.00%	0.00%	0.00%	0.00%	44.04%	76.84%	-20.89%
66									
67	StaTax		387,956	-	-	-	141,345	246,611	-
68		TRUE	100.00%	0.00%	0.00%	0.00%	36.43%	63.57%	0.00%
69									
70	FedTax		399,094	-	-	-	145,403	253,691	-
71		TRUE	100.00%	0.00%	0.00%	0.00%	36.43%	63.57%	0.00%
72									
73	Plant		35,369,114	-	-	-	16,078,870	15,971,808	3,318,436
74		TRUE	100.00%	0.00%	0.00%	0.00%	45.46%	45.16%	9.38%
75									

ClassF **Citizens Electric Company of Lewisburg**
Classi **Embedded Cost of Service Study (ECOSS) (R)**
Fac **FPFTY Ending December 31, 2026**
E-5C (**Classification Factors**

0	Allocator Name	In Use	Total	Demand	Commodity	Customer
1	None		0			
2		FALSE	0.00%	0.00%	0.00%	0.00%
3						
4	Demand		1	1		
5		TRUE	100.00%	100.00%	0.00%	0.00%
6						
7	Commodity		1		1	
8		TRUE	100.00%	0.00%	100.00%	0.00%
9						
10	Customer		1			1
11		TRUE	100.00%	0.00%	0.00%	100.00%
12						
13	PTF-Sec-Z		100.00%	19.31%	0.00%	80.69%
14		TRUE	100.00%	19.31%	0.00%	80.69%
15						
16	OH-Sec-Z		100.00%	22.60%	0.00%	77.40%
17		TRUE	100.00%	22.60%	0.00%	77.40%
18						
19	UG-Sec-Z		100.00%	42.89%	0.00%	57.11%
20		TRUE	100.00%	42.89%	0.00%	57.11%
21						
22	Trans-Min		100.00%	64.15%	0.00%	35.85%
23		TRUE	100.00%	64.15%	0.00%	35.85%
24						
25	Sec_RB		7,284,432	1,732,619	-	5,551,812
26		TRUE	100.00%	23.79%	0.00%	76.21%
27						
28	Sec-Pt		15,971,808	5,505,500	-	10,466,308
29		TRUE	100.00%	34.47%	0.00%	65.53%
30						
31	Sec-RB		7,284,432	1,732,619	-	5,551,812
32		TRUE	100.00%	23.79%	0.00%	76.21%
33						
34	Sec-OH_UG		23,619,681	13,153,373	-	10,466,308
35		TRUE	100.00%	55.69%	0.00%	44.31%
36						

ClassF **Citizens Electric Company of Lewisburg**
Classi **Embedded Cost of Service Study (ECOSS) (R)**
Fac **FPFTY Ending December 31, 2026**
E-5C (**Classification Factors**

0	Allocator Name	In Use	Total	Demand	Commodity	Customer
37	Sec-GenPt		1,060,759	405,155	-	655,605
38		TRUE	100.00%	38.19%	0.00%	61.81%
39						
40	Sec-OpExp		954,797	360,848	-	593,948
41		TRUE	100.00%	37.79%	0.00%	62.21%
42						
43	Sec-DiPt		14,911,049	5,100,346	-	9,810,703
44		TRUE	100.00%	34.21%	0.00%	65.79%
45						
46	Sec-Lab		153,276	58,544	-	94,733
47		TRUE	100.00%	38.19%	0.00%	61.81%
48						
49	Sec-Rev		1,979,820	647,985	-	1,331,834
50		TRUE	100.00%	32.73%	0.00%	67.27%
51						
52	Sec-LabPt		200.00%	72.66%	0.00%	127.34%
53		TRUE	100.00%	36.33%	0.00%	63.67%
54						
55	Sec-PreTax		246,611	25,399	-	221,212
56		TRUE	100.00%	10.30%	0.00%	89.70%
57						
55	Sec-StaTax		246,611	25,399	-	221,212
58		TRUE	100.00%	10.30%	0.00%	89.70%
59						
58	Sec-FedTax		253,691	26,128	-	227,563
60		TRUE	100.00%	10.30%	0.00%	89.70%
61						
58	Sec-RetRRPF		2,235,521	731,675	-	1,503,846
62		TRUE	100.00%	32.73%	0.00%	67.27%
63						

AllocFc **Citizens Electric Company of Lewisburg**
Class A **Embedded Cost of Service Study (ECOSS) (R)**
Fac **FPFTY Ending December 31, 2026**
E-5D (I **Class Allocation Factors**

0	Allocator Name	In Use	Total	RS	SH	GLP-1	GLP-3	MBL	OL
1	None		-						
2		FALSE	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
3									
4	MWh-Meter		161,837,666	87,664,162	181,607	27,208,762	46,600,138	49,526	133,471
5		TRUE	100.00%	54.17%	0.11%	16.81%	28.79%	0.03%	0.08%
6									
7	NCP-Prim		100.00%	61.11%	0.16%	14.54%	23.96%	0.05%	0.18%
8		TRUE	100.00%	61.11%	0.16%	14.54%	23.96%	0.05%	0.18%
9									
10	NCP-Sec		100.00%	69.64%	0.19%	16.57%	13.35%	0.05%	0.20%
11		TRUE	100.00%	69.64%	0.19%	16.57%	13.35%	0.05%	0.20%
12									
13	NCP-Ltr		13,959	5,947	64	2,509	5,337	21	81
14		TRUE	100.00%	42.60%	0.46%	17.98%	38.23%	0.15%	0.58%
15									
16	NoneX								
17		FALSE	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
18									
19	AVG-CUST		7,272	6,051	3	1,137	42	13	26
20		TRUE	100.00%	83.21%	0.04%	15.64%	0.58%	0.18%	0.36%
21									
22	Avg-Cust-Sec		7,267	6,051	3	1,132	42	13	26
23		TRUE	100.00%	83.27%	0.04%	15.58%	0.58%	0.18%	0.36%
24									
25	Services_Cost		6,753,684	5,612,820	2,656	1,078,485	46,616	13,107	-
26		TRUE	100.00%	83.11%	0.04%	15.97%	0.69%	0.19%	0.00%
27									
28	Meters		7,272	6,051	3	1,137	42	13	26
29		TRUE	100.00%	83.21%	0.04%	15.64%	0.58%	0.18%	0.36%
30									
31	Meter_Cost		2,563,965	1,821,021	871	601,252	140,821	-	-
32		TRUE	100.00%	71.02%	0.03%	23.45%	5.49%	0.00%	0.00%
33									
34	Dist_Rev		6,055,143	3,903,746	8,741	1,092,138	909,143	26,151	115,224
35		TRUE	100.00%	64.47%	0.14%	18.04%	15.01%	0.43%	1.90%
36									

AllocFc **Citizens Electric Company of Lewisburg**
Class A **Embedded Cost of Service Study (ECOSS) (R)**
Fac **FPFTY Ending December 31, 2026**
E-5D (I **Class Allocation Factors**

0	Allocator Name	In Use	Total	RS	SH	GLP-1	GLP-3	MBL	OL
37	CustDeposits		206,700	34,212	51	91,269	81,169	-	-
38		TRUE	100.00%	16.55%	0.02%	44.16%	39.27%	0.00%	0.00%
39									
40	Write-Offs		6,055,143	3,903,746	8,741	1,092,138	909,143	26,151	115,224
41		TRUE	100.00%	64.47%	0.14%	18.04%	15.01%	0.43%	1.90%
42									
43	StLgt-Cost		617,453	-	-	-	-	242,410	375,043
44		TRUE	100.00%	0.00%	0.00%	0.00%	0.00%	39.26%	60.74%
45									
46	PriD-Lab		307,436	187,875	506	44,694	73,671	142	548
47		TRUE	100.00%	61.11%	0.16%	14.54%	23.96%	0.05%	0.18%
48									
49	PriD-DxPt		13,951,239	8,525,642	22,945	2,028,198	3,343,155	6,439	24,860
50		TRUE	100.00%	61.11%	0.16%	14.54%	23.96%	0.05%	0.18%
51									
52	PriD-Pt		16,078,870	9,825,844	26,444	2,337,509	3,853,002	7,421	28,651
53		TRUE	100.00%	61.11%	0.16%	14.54%	23.96%	0.05%	0.18%
54									
55	PriD-LabPt		200.00%	122.22%	0.33%	29.08%	47.93%	0.09%	0.36%
56		TRUE	100.00%	61.11%	0.16%	14.54%	23.96%	0.05%	0.18%
57									
58	PriD-OpExp		1,861,936	1,137,835	3,062	270,684	446,178	859	3,318
59		TRUE	100.00%	61.11%	0.16%	14.54%	23.96%	0.05%	0.18%
60									
61	SecD-Lab		58,544	37,863	139	9,850	10,490	41	160
62		TRUE	100.00%	64.68%	0.24%	16.83%	17.92%	0.07%	0.27%
63									
64	SecD-DxPt		5,100,346	2,624,195	18,877	893,296	1,534,589	6,046	23,343
65		TRUE	100.00%	51.45%	0.37%	17.51%	30.09%	0.12%	0.46%
66									
67	SecD-Pt		5,505,500	2,886,231	19,838	961,466	1,607,186	6,332	24,447
68		TRUE	100.00%	52.42%	0.36%	17.46%	29.19%	0.12%	0.44%
69									

AllocFc **Citizens Electric Company of Lewisburg**
Class A **Embedded Cost of Service Study (ECOSS) (R)**
Fac **FPFTY Ending December 31, 2026**
E-5D (I **Class Allocation Factors**

0	Allocator Name	In Use	Total	RS	SH	GLP-1	GLP-3	MBL	OL
70	SecD-UG		885,449	616,630	1,660	146,693	118,203	466	1,798
71		TRUE	100.00%	69.64%	0.19%	16.57%	13.35%	0.05%	0.20%
72									
73	SecD-LabPt		200.00%	117.10%	0.60%	34.29%	47.11%	0.19%	0.72%
74		TRUE	100.00%	58.55%	0.30%	17.14%	23.56%	0.09%	0.36%
75									
76	SecD-OpExp		360,848	230,986	880	60,840	66,862	263	1,017
77		TRUE	100.00%	64.01%	0.24%	16.86%	18.53%	0.07%	0.28%
78									
79	SecC-Lab		94,733	66,860	33	12,563	464	5,790	9,023
80		TRUE	100.00%	70.58%	0.03%	13.26%	0.49%	6.11%	9.52%
81									
82	SecC-DxPt		9,810,703	7,475,976	3,614	1,422,214	57,503	338,805	512,591
83		TRUE	100.00%	76.20%	0.04%	14.50%	0.59%	3.45%	5.22%
84									
85	SecC-Pt		10,466,308	7,938,686	3,843	1,509,159	60,715	378,873	575,033
86		TRUE	100.00%	75.85%	0.04%	14.42%	0.58%	3.62%	5.49%
87									
88	SecC-IntPt		-	-	-	-	-	-	-
89		FALSE	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
90									
91	SecC-LTr		-	-	-	-	-	-	-
92		FALSE	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
93									
94	SecC-LabPt		200.00%	146.43%	0.07%	27.68%	1.07%	9.73%	15.02%
95		TRUE	100.00%	73.21%	0.04%	13.84%	0.53%	4.87%	7.51%
96									
97	SecC-OpExp		593,948	440,245	218	82,852	3,097	26,401	41,136
98		TRUE	100.00%	74.12%	0.04%	13.95%	0.52%	4.45%	6.93%
99									

AllocFc **Citizens Electric Company of Lewisburg**
Class A **Embedded Cost of Service Study (ECOSS) (R)**
Fac **FPFTY Ending December 31, 2026**
E-5D (I **Class Allocation Factors**

0	Allocator Name	In Use	Total	RS	SH	GLP-1	GLP-3	MBL	OL
100	Bill-Lab		219,589	179,954	89	36,106	2,383	352	704
101		TRUE	100.00%	81.95%	0.04%	16.44%	1.09%	0.16%	0.32%
102									
103	Bill-DxLab		43,525	33,452	16	8,578	1,366	37	74
104		TRUE	100.00%	76.86%	0.04%	19.71%	3.14%	0.09%	0.17%
105									
106	Bill-DxPt		1,798,757	1,277,542	611	421,810	98,793	-	-
107		TRUE	100.00%	71.02%	0.03%	23.45%	5.49%	0.00%	0.00%
108									
109	Bill-Pt		3,318,436	2,522,926	1,227	671,687	115,287	2,436	4,872
110		TRUE	100.00%	76.03%	0.04%	20.24%	3.47%	0.07%	0.15%
111									
112	Bill-LabPt		200.00%	157.98%	0.08%	36.68%	4.56%	0.23%	0.47%
113		TRUE	100.00%	78.99%	0.04%	18.34%	2.28%	0.12%	0.23%
114									
115	Bill-OpExp		1,173,899	935,395	594	195,114	32,702	3,513	6,580
116		TRUE	100.00%	79.68%	0.05%	16.62%	2.79%	0.30%	0.56%
117									
118	PreTax		320,926	25,415	1,509	206,364	94,063	(28,468)	22,043
119		TRUE	100.00%	7.92%	0.47%	64.30%	29.31%	-8.87%	6.87%
120									
121	PreTax-Sta		35,369,114	23,173,687	51,352	5,479,820	5,636,190	395,062	633,003
122		TRUE	100.00%	65.52%	0.15%	15.49%	15.94%	1.12%	1.79%
123									
124	PreTax-Fed		360,407	32,712	1,525	208,090	95,838	-	22,242
125		TRUE	100.00%	9.08%	0.42%	57.74%	26.59%	0.00%	6.17%
126									
127	Labor		680,301	472,553	767	103,214	87,009	6,325	10,434
128		TRUE	100.00%	69.46%	0.11%	15.17%	12.79%	0.93%	1.53%
129									
130	Plant		35,369,114	23,173,687	51,352	5,479,820	5,636,190	395,062	633,003
131		TRUE	100.00%	65.52%	0.15%	15.49%	15.94%	1.12%	1.79%
132									
133	RateBase		17,199,344	11,466,975	21,100	2,616,738	2,367,878	282,654	443,999
134		TRUE	100.00%	66.67%	0.12%	15.21%	13.77%	1.64%	2.58%
135									

WP (R)

Citizens' Electric Company of Lewisburg
Rate Case with Fully Projected Future Test Year 2026 (R)
INDEX TO WORKPAPERS

Line	WORKPAPER	DESCRIPTION	PERIOD
	INDEX TO WORKPAPERS		
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3	Workpaper 2 to Schedule B	Monthly Billing Units, Rates And Revenue	Historic Year 2024
4	Workpaper 3 to Schedule B	Monthly Customers	Historic Year 2024
5	Workpaper 1 to Schedule C	Historic and Forecast O&M	Years 2013-2026
6	Workpaper 2 to Schedule C	Accumulated Deferred Income Taxes	Years 2024 through 2026
7	Workpaper 1 to Schedule D	Components of Capital Projects- Zero Load Analysis	HY 2024
8	Workpaper 2 to Schedule D	Transformer Costs and Replacements	HY 2024
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Citizens' Electric Company of Lewisburg
Rate Case with Fully Projected Future Test Year 2026 (R)
Workpaper 1 to Schedule B
Sales Recap
Period Ending December 31, 2024

Line	Customer Class	Acct. #	Type	Class	January	February	March	April	May	June	July
1	RS - KWH	440.10	KWH	RS	116,530	119,373	97,861	92,785	77,839	88,582	111,374
2	RS - Facility	440.20	Facility	RS	41,086	41,055	41,052	41,041	41,050	41,042	41,140
3	RS - STAS	440.40	STAS	RS	(67)	(64)	(54)	(51)	(44)	(43)	(53)
4	RS - KWHGEN	440.50	Gen	RS	382,566	353,059	289,404	274,496	230,272	221,708	278,824
5	RSH - KWH	441.10	KWH	RS	197,597	204,339	154,564	135,210	95,098	97,550	114,833
6	RSH - Facility	441.20	Facility	RS	36,773	36,804	36,740	36,844	36,805	36,830	36,871
7	RSH - STAS	441.40	STAS	RS	(110)	(106)	(81)	(72)	(52)	(47)	(54)
8	RSH - KWHGEN	441.50	Gen	RS	650,356	605,881	458,269	400,900	281,971	244,531	287,833
9	GLP1 - KWH2	442.10	KWH	GLP1	74,379	79,502	71,753	70,539	67,879	69,113	73,731
10	GLP1 - Facility	442.20	Facility	GLP1	18,051	18,027	18,012	18,053	18,045	18,132	18,065
11	GLP1 - KW2	442.30	KW	GLP1	-	-	-	-	-	-	-
12	GLP1 - STAS	442.40	STAS	GLP1	(41)	(41)	(35)	(33)	(30)	(29)	(32)
13	GLP1 - KWHGEN	442.50	Gen	GLP1	231,096	225,870	187,982	175,780	150,512	143,860	168,682
14	GLP3 - KWH3	443.10	KWH	GLP3	2,499	2,755	2,470	2,403	2,391	2,469	2,549
15	GLP3 - KW AND KW2	443.20	KW	GLP3	21,735	23,668	22,025	22,073	22,765	23,083	23,612
16	GLPP - KWH3	443.21	KWH	GLP3	2,886	2,690	2,527	2,855	3,214	3,547	3,702
17	GLPP - KWVD	443.22	KW	GLP3	(827)	(684)	(688)	(772)	(869)	(920)	(984)
18	GLPP - KW	443.23	KW	GLP3	25,222	20,624	20,266	23,843	27,487	28,402	29,642
19	GLPP - KWHGEN	443.24	Gen	GLP3	10,115	11,032	5,277	4,317	3,837	3,041	3,854
20	GLPP - Facility	443.25	Facility	GLP3	275	275	275	275	275	275	275
21	GLPP - STAS	443.26	STAS	GLP3	(5)	(4)	(3)	(4)	(4)	(4)	(5)
22	GLP3 - KWHGEN	443.30	Gen	GLP3	50,131	47,980	42,175	42,050	43,067	36,866	38,459
23	GLP3 - Facility	443.40	Facility	GLP3	1,815	1,815	1,815	1,826	1,749	1,760	1,760
24	GLP3 - STAS	443.50	STAS	GLP3	(13)	(13)	(12)	(12)	(13)	(15)	(13)
25	GLPP - RTP - GEN	443.64	Gen	GLP3	3,765	3,670	3,442	3,670	3,557	3,730	3,613
26	GPL3 - RTP - KWH3	443.71	KWH	GLP3	259	259	254	268	402	1,550	481
27	GPL3 - RTP - KW AN	443.73	KW	GLP3	2,219	1,559	1,763	2,036	7,070	21,428	9,416
28	GPL3 - RTP - GEN	443.74	Gen	GLP3	11,037	13,135	9,436	9,639	11,189	28,315	13,967
29	GPL3 - RTP - Facility	443.75	Facility	GLP3	110	110	110	110	110	110	110
30	Public Street&Hwy B	444.10	Facility	OL	1,149	1,134	1,126	1,127	1,105	1,102	1,107
31	LED - KWH	444.11	Facility	OL	8,271	8,389	8,391	8,346	8,366	8,335	8,329
32	MBL - KWHGEN	444.22	Gen	MBL	932	821	677	647	557	422	367
33	MBL - Facility	444.23	Facility	MBL	2,183	2,183	2,183	2,183	2,183	2,183	2,183
34	MBL - STAS	444.24	STAS	MBL	(0)	(0)	(0)	(0)	(0)	(0)	(0)
35	SL Only - STAS	444.40	STAS	OL	(1)	(1)	(1)	(1)	(1)	(1)	(1)
36	Public St&Hwy Ltg-C	444.50	Gen	OL	770	760	752	748	734	573	577
37	LED - KWHGEN	444.51	Gen	OL	1,185	1,212	1,215	1,209	1,211	889	888
38	SH - KWH	445.10	KWH	SH	629	927	729	501	270	114	122
39	SH - KWHGEN	445.20	Gen	SH	472	670	508	358	180	39	64
40	SH - Facility	445.30	Facility	SH	81	81	81	81	81	81	81
41	SH - STAS	445.40	STAS	SH	(0)	(0)	(0)	(0)	(0)	(0)	(0)
42	Bucknell Reservation	449.00	BU	GLP3	12,225	12,550	12,502	12,357	10,128	3,490	9,177
43	Totals				1,907,331	1,841,295	1,494,763	1,387,624	1,150,387	1,132,093	1,284,549

Citizens' Electric Company of Lewisburg
Rate Case with Fully Projected Future Test Year 2026 (R)
Workpaper 1 to Schedule B
Sales Recap
Period Ending December 31, 2024

Line	Customer Class	Acct. #	Type	Class	January	February	March	April	May	June	July
44											
45	Distribution	kWH			394,778	409,844	330,158	304,560	247,093	262,926	306,793
46	Facility	Facility			109,792	109,872	109,785	109,887	109,769	109,850	109,921
47	Demand	kW			48,349	45,168	43,366	47,180	56,453	71,992	61,686
48	Reservation Charge	BU			12,225	12,550	12,502	12,357	10,128	3,490	9,177
49	Total Distribution				565,144	577,434	495,811	473,985	423,444	448,258	487,577
50	Generation	Gen			1,342,425	1,264,091	999,139	913,812	727,087	683,974	797,129
51	STAS	STAS			(238)	(230)	(187)	(173)	(144)	(139)	(157)
52					1,907,331	1,841,295	1,494,763	1,387,624	1,150,387	1,132,093	1,284,549
53											
54	RS/RSH				391,985	401,570	330,217	305,880	250,792	264,004	304,218
55	GLP1				92,430	97,528	89,766	88,592	85,924	87,245	91,796
56	GLP3				68,418	65,622	63,318	67,275	74,722	85,193	79,741
57	SH				709	1,008	809	582	351	195	202
58	MBL				2,183	2,183	2,183	2,183	2,183	2,183	2,183
59	OL				9,419	9,523	9,517	9,473	9,471	9,437	9,436
60					565,144	577,434	495,811	473,985	423,444	448,258	487,577
61	Generation				1,342,425	1,264,091	999,139	913,812	727,087	683,974	797,129
62	STAS				(238)	(230)	(187)	(173)	(144)	(139)	(157)
63					1,907,331	1,841,295	1,494,763	1,387,624	1,150,387	1,132,093	1,284,549
64											
65	Excess Demand GLP	$3.74			-	-	-	-	-	-	-
66											

Citizens' Electric Company of Lewisburg
Rate Case with Fully Projected Future Test Year
Workpaper 1 to Schedule B
Sales Recap
Period Ending December 31, 2024

Line	Customer Class	Acct. #	Type	Class	August	September	October	November	December	Totals
1	RS - KWH	440.10	KWH	RS	115,389	94,446	77,056	82,064	105,658	1,178,957
2	RS - Facility	440.20	Facility	RS	41,131	41,123	41,121	41,163	41,112	493,117
3	RS - STAS	440.40	STAS	RS	(54)	(46)	(38)	(41)	(53)	(608)
4	RS - KWHGEN	440.50	Gen	RS	288,810	236,307	192,837	205,390	273,327	3,226,999
5	RSH - KWH	441.10	KWH	RS	113,845	96,420	84,112	105,426	174,459	1,573,452
6	RSH - Facility	441.20	Facility	RS	36,886	37,178	37,156	37,311	37,367	443,565
7	RSH - STAS	441.40	STAS	RS	(54)	(46)	(41)	(50)	(83)	(795)
8	RSH - KWHGEN	441.50	Gen	RS	285,314	241,638	210,810	264,279	452,050	4,383,832
9	GLP1 - KWH2	442.10	KWH	GLP1	73,046	67,664	65,814	68,183	72,547	854,150
10	GLP1 - Facility	442.20	Facility	GLP1	18,033	18,065	18,293	17,941	18,139	216,856
11	GLP1 - KW2	442.30	KW	GLP1	-	-	-	-	-	-
12	GLP1 - STAS	442.40	STAS	GLP1	(32)	(29)	(27)	(28)	(32)	(388)
13	GLP1 - KWHGEN	442.50	Gen	GLP1	172,444	152,088	130,294	136,562	165,024	2,040,195
14	GLP3 - KWH3	443.10	KWH	GLP3	2,725	2,662	2,409	2,308	2,406	30,047
15	GLP3 - KW AND KW2	443.20	KW	GLP3	23,789	24,758	23,108	21,613	23,039	275,269
16	GLPP - KWH3	443.21	KWH	GLP3	3,991	3,973	3,430	3,260	2,919	38,995
17	GLPP - KWVD	443.22	KW	GLP3	(1,019)	(982)	(878)	(798)	(820)	(10,243)
18	GLPP - KW	443.23	KW	GLP3	30,680	29,887	27,671	26,279	26,636	316,639
19	GLPP - KWHGEN	443.24	Gen	GLP3	4,055	3,854	4,256	3,649	5,867	63,156
20	GLPP - Facility	443.25	Facility	GLP3	275	275	275	275	275	3,300
21	GLPP - STAS	443.26	STAS	GLP3	(5)	(5)	(4)	(4)	(4)	(52)
22	GLP3 - KWHGEN	443.30	Gen	GLP3	41,412	49,702	45,101	45,277	49,440	531,662
23	GLP3 - Facility	443.40	Facility	GLP3	1,764	1,791	1,815	1,815	1,815	21,540
24	GLP3 - STAS	443.50	STAS	GLP3	(16)	(15)	(13)	(15)	(13)	(164)
25	GLPP - RTP - GEN	443.64	Gen	GLP3	3,729	3,731	3,615	3,731	3,616	43,870
26	GPL3 - RTP - KWH3	443.71	KWH	GLP3	1,264	892	538	1,500	271	7,937
27	GPL3 - RTP - KW AN	443.73	KW	GLP3	20,214	12,102	7,483	23,260	2,717	111,267
28	GPL3 - RTP - GEN	443.74	Gen	GLP3	26,511	17,386	13,533	20,553	10,509	185,210
29	GPL3 - RTP - Facility	443.75	Facility	GLP3	110	110	110	110	110	1,320
30	Public Street&Hwy B	444.10	Facility	OL	1,107	1,024	976	968	939	12,864
31	LED - KWH	444.11	Facility	OL	8,326	8,468	8,551	8,589	8,628	100,988
32	MBL - KWHGEN	444.22	Gen	MBL	399	452	509	578	679	7,042
33	MBL - Facility	444.23	Facility	MBL	2,183	2,183	2,183	2,183	2,183	26,198
34	MBL - STAS	444.24	STAS	MBL	(0)	(0)	(0)	(0)	(0)	(4)
35	SL Only - STAS	444.40	STAS	OL	(1)	(1)	(1)	(1)	(1)	(11)
36	Public St&Hwy Ltg-C	444.50	Gen	OL	584	567	567	568	530	7,729
37	LED - KWHGEN	444.51	Gen	OL	888	895	900	909	981	12,380
38	SH - KWH	445.10	KWH	SH	125	124	100	174	386	4,201
39	SH - KWHGEN	445.20	Gen	SH	85	69	21	67	211	2,743
40	SH - Facility	445.30	Facility	SH	81	79	61	61	61	907
41	SH - STAS	445.40	STAS	SH	(0)	(0)	(0)	(0)	(0)	(1)
42	Bucknell Reservation	449.00	BU	GLP3	4,165	7,899	9,960	2,514	12,104	109,071
43	Totals				1,322,176	1,156,690	1,013,663	1,127,620	1,495,000	16,313,189

Citizens' Electric Company of Lewisburg
Rate Case with Fully Projected Future Test Year
Workpaper 1 to Schedule B
Sales Recap
Period Ending December 31, 2024

Line	Customer Class	Acct. #	Type	Class	August	September	October	November	December	Totals
44										
45	Distribution	kWH			310,384	266,181	233,460	262,915	358,647	3,687,739
46	Facility	Facility			109,895	110,297	110,540	110,415	110,630	1,320,655
47	Demand	kW			73,663	65,765	57,383	70,354	51,572	692,931
48	Reservation Charge	BU			4,165	7,899	9,960	2,514	12,104	109,071
49	Total Distribution				498,107	450,143	411,344	446,197	532,953	5,810,395
50	Generation	Gen			824,231	706,689	602,443	681,562	962,235	10,504,818
51	STAS	STAS			(162)	(142)	(124)	(139)	(188)	(2,023)
52					1,322,176	1,156,690	1,013,663	1,127,620	1,495,000	16,313,189
53										
54	RS/RSH				307,250	269,168	239,445	265,963	358,597	3,689,090
55	GLP1				91,079	85,729	84,107	86,124	90,686	1,071,006
56	GLP3				87,957	83,367	75,921	82,136	71,472	905,140
57	SH				206	204	161	235	447	5,108
58	MBL				2,183	2,183	2,183	2,183	2,183	26,198
59	OL				9,433	9,492	9,527	9,557	9,568	113,852
60					498,107	450,143	411,344	446,197	532,953	5,810,395
61	Generation				824,231	706,689	602,443	681,562	962,235	10,504,818
62	STAS				(162)	(142)	(124)	(139)	(188)	(2,023)
63					1,322,176	1,156,690	1,013,663	1,127,620	1,495,000	16,313,189
64										
65	Excess Demand GLP	$3.74			-	-	-	-	-	-
66										

Citizens' Electric Company of Lewisburg
Rate Case with Fully Projected Future Test Year 2026 (R)
Workpaper 1 to Schedule C
Historic and Forecast O&M
Years 2013-2026

Line	Account	Acct No	2023 Total	2024 Total	2025 Total	2026 Total
1	Ops Exp Eng	580	139,449	147,492	151,142	154,958
1	Station Exp	582	20,968	5,258	13,979	14,046
2	OH. Line Exp	583	190,281	191,665	181,002	188,043
3	OH. Line Contra (to Plant)	583.97	(25,570)	(17,480)	(18,034)	(19,270)
4	URD Line Exp	584	77,898	51,848	71,959	73,299
5	Dusk to Dawn Lgts Exp	585DD	3,103	5,271	937	965
6	St Lgt & Signal Exp	585SLS	4,992	6,898	4,088	4,172
7	Meter Exp	586	43,734	53,805	56,277	58,501
8	Meter Contra (to Plant)	586.98	(18,472)	(29,763)	(7,319)	(7,789)
9	Customer Inst Exp	587	39,845	41,115	53,765	56,416
10	Misc. Distribution Exp	588	164,611	211,070	207,816	210,622
11	Tools	588.5	5,685	13,479	8,000	8,500
12	Travel	588.6	74,111	25,691	81,116	83,446
13	Safety & Training	588.7	38,404	76,891	42,600	45,000
14	Mapping	588.8	43,586	23,327	36,446	37,248
15	Retiree Non Alloc BC+SERF	588.1	68,659	104,646	110,437	110,437
16	Rents	589	520	530	525	525
17	Total Ops		871,804	911,743	994,735	1,019,120
18					*994,735*	
19	Maint. Sub-Station Exp	592	2,202	25,133	16,832	17,209
20	Maint. OH. Line Exp	593	322,454	303,733	379,720	397,470
21	Veg Mgmt	593.5	193,991	214,296	209,204	367,143
22	Pole Insp Mgmt	593.6	47,080	40,536	78,287	62,223
23	Maint. URD Line Exp	594	16,532	13,331	14,361	14,827
24	Maint. Line Xfmr	595	85,912	31,968	26,967	27,468
25	Maint. Dusk to Dawn Lgts	596DD	6,450	1,307	6,605	6,676
26	Maint. St Lgt & Signal Exp	596SLS	16,397	14,607	16,992	17,512
27	Maint. of Meter Exp	597	0	0	0	0
28	Total Maintenance		691,018	644,911	748,968	910,527
29					*748,968*	
30	Meter Reading Exp	902	25,085	26,338	26,000	26,000
31	Customer Records Exp	903	474,976	483,001	486,259	492,479
32	Uncollectibles	904	31,906	27,330	30,000	30,900
33	Total Customer Accounts		531,968	536,669	542,259	549,379

Citizens' Electric Company of Lewisburg
Rate Case with Fully Projected Future Test Y
Workpaper 1 to Schedule C
Historic and Forecast O&M
Years 2013-2026

Line	Account	Acct No	2023 Labor	2024 Labor	2025 Labor	2026 Labor	2023 OH	2024 OH	2025 OH	2026 OH
1	Ops Exp Eng	580	65,639	69,376	70,506	73,380	73,810	78,116	80,636	81,578
1	Station Exp	582	8,446	1,974	5,821	5,941	9,871	2,264	6,657	6,605
2	OH. Line Exp	583	76,244	81,245	76,212	77,784	90,703	86,954	87,163	86,474
3	OH. Line Contra (to Plant)	583.97		(12,893)						
4	URD Line Exp	584	29,963	12,441	22,843	23,314	33,959	15,023	26,126	25,919
5	Dusk to Dawn Lgts Exp	585DD	345	3,214	407	415	2,728	1,569	465	462
6	St Lgt & Signal Exp	585SLS	2,093	1,606	1,788	1,825	2,363	3,632	2,044	2,028
7	Meter Exp	586	18,234	22,362	22,504	22,968	17,980	25,203	25,737	25,534
8	Meter Contra (to Plant)	586.98		(29,763)						
9	Customer Inst Exp	587	16,746	19,074	21,945	22,397	17,868	21,926	25,098	24,900
10	Misc. Distribution Exp	588	78,384	100,860	93,125	95,045	79,239	103,026	106,506	105,664
11	Tools	588.5								
12	Travel	588.6	28,955		28,510	29,098	32,533	25,691	32,606	32,349
13	Safety & Training	588.7		19,559				22,411		
14	Mapping	588.8	9,306	757	5,527	5,641	10,515	816	6,321	6,271
15	Retiree Non Alloc BC+SERF	588.1								
16	Rents	589						530		
17	Total Ops		334,356	289,812	349,187	357,808	371,570	387,161	399,361	397,784
18										
19	Maint. Sub-Station Exp	592	1,134	11,213	7,461	7,615	843	13,236	8,533	8,466
20	Maint. OH. Line Exp	593	133,851	117,957	156,035	159,253	152,261	155,041	178,455	177,045
21	Veg Mgmt	593.5	7,497	21,787	5,815	5,815	7,527	24,661	6,651	6,465
22	Pole Insp Mgmt	593.6	846	0	2,000	2,000	907	0	2,287	2,223
23	Maint. URD Line Exp	594	6,923	5,237	6,159	6,286	8,026	6,471	7,044	6,989
24	Maint. Line Xfmr	595	9,440	7,462	7,377	7,529	11,103	9,494	8,437	8,370
25	Maint. Dusk to Dawn Lgts	596DD	2,888	550	1,813	1,851	2,822	617	2,074	2,058
26	Maint. St Lgt & Signal Exp	596SLS	7,303	5,733	7,362	7,514	7,491	7,586	8,420	8,354
27	Maint. of Meter Exp	597	0	0	0	0	0	0	0	0
28	Total Maintenance		169,882	169,939	194,023	197,863	190,979	217,106	221,902	219,969
29										
30	Meter Reading Exp	902	0	0	0	0	0	0	0	0
31	Customer Records Exp	903	176,064	174,418	174,043	179,475	192,911	197,831	199,051	199,527
32	Uncollectibles	904								
33	Total Customer Accounts		176,064	174,418	174,043	179,475	192,911	197,831	199,051	199,527

Line	Account	Acct No	2023 Transp	2024 Transp	2025 Transp	2026 Transp	2023 Material	2024 Material	2025 Material	2026 Material
1	Ops Exp Eng	580								
1	Station Exp	582		0			2,651	1,020	1,500	1,500
2	OH. Line Exp	583	23,463	23,466	17,127	23,285	(128)		500	500
3	OH. Line Contra (to Plant)	583.97		2,251			(25,570)	(6,838)	(18,034)	(19,270)
4	URD Line Exp	584	12,286		2,990	4,065	1,690	24,384	20,000	20,000
5	Dusk to Dawn Lgts Exp	585DD	30	488	65	88	0	0	0	0
6	St Lgt & Signal Exp	585SLS	474	1,660	176	239	62	0	80	80
7	Meter Exp	586	5,075	4,512	5,460	7,423	2,445	1,728	2,576	2,576
8	Meter Contra (to Plant)	586.98					(18,472)		(7,319)	(7,789)
9	Customer Inst Exp	587	5,231		6,668	9,065	0	115	54	54
10	Misc. Distribution Exp	588	4,026	4,678	4,804	6,532	2,961	2,506	3,381	3,381
11	Tools	588.5		3,237			5,685	10,242	8,000	8,500
12	Travel	588.6					12,622		20,000	22,000
13	Safety & Training	588.7		233			38,404	34,688	42,600	45,000
14	Mapping	588.8		0			23,765	21,754	24,598	25,336
15	Retiree Non Alloc BC+SERF	588.1					68,659	104,646	110,437	110,437
16	Rents	589					520		525	525
17	Total Ops		50,585	40,525	37,289	50,696	115,294	194,245	208,898	212,831
18										
19	Maint. Sub-Station Exp	592	225	623	809	1,100	0	61	29	29
20	Maint. OH. Line Exp	593	36,306	30,857	44,338	60,280	37	(122)	892	892
21	Veg Mgmt	593.5	2,467	1,087	1,738	2,363	176,500	166,761	195,000	352,500
22	Pole Insp Mgmt	593.6	378	0	0	0	44,949	40,536	74,000	58,000
23	Maint. URD Line Exp	594	1,515	1,546	1,097	1,491	67	77	60	60
24	Maint. Line Xfmr	595	3,605	1,094	1,154	1,569	61,764	13,918	10,000	10,000
25	Maint. Dusk to Dawn Lgts	596DD	740	140	139	188	0	0	2,579	2,579
26	Maint. St Lgt & Signal Exp	596SLS	1,603	1,288	1,209	1,644	0	0	0	0
27	Maint. of Meter Exp	597	0	0	0	0	0	0	0	0
28	Total Maintenance		46,839	36,635	50,483	68,635	283,318	221,231	282,560	424,060
29										
30	Meter Reading Exp	902	0	0	0	0	25,085	26,338	26,000	26,000
31	Customer Records Exp	903	3,558	949	866	1,178	102,444	109,803	112,299	112,299
32	Uncollectibles	904					31,906	27,330	30,000	30,900
33	Total Customer Accounts		3,558	949	866	1,178	159,435	163,471	168,299	169,199

Citizens' Electric Company of Lewisburg
Rate Case with Fully Projected Future Test Year 2026 (R)
Workpaper 1 to Schedule C
Historic and Forecast O&M
Years 2013-2026

Line	Account	Acct No	2023 Total	2024 Total	2025 Total	2026 Total
34					542,259	
35	Administrative	920	742,994	700,832	732,830	884,948
36	Misc Admin	921	(37,543)	15,396	6,199	6,385
37	Misc Admin- Travel	921.1	20,548	7,817	10,000	10,300
38	Misc Admin- Comm	921.2	32,667	40,255	34,014	35,035
39	Misc Admin- Call Center	921.3	77,386	82,455	85,379	87,940
40	Misc Admin- Transp	921.4	9,655	0	11,267	11,605
41	Outside Services	923	47,103	40,008	37,000	38,110
42	Property Insurance	924	11,431	11,190	11,059	11,059
43	Injury & Damage Exp	925	27,561	27,341	28,907	28,907
44	CEO Insurance	926.01	(8,321)	(5,885)	0	0
45	Benefits	926.00	14,525	13,382	8,500	8,755
46	Reg Commission Exp	928	105,515	70,128	88,208	108,889
47	General Advertising	930.1	1,061	655	1,000	1,030
48	Misc. General Exp	930.2	89,888	93,095	94,112	96,935
49	Director's Committee	930.3	14,352	16,850	15,779	16,252
50	Misc. General Plant	932.4	121,914	155,101	164,713	165,455
51	Total General Labor		1,270,735	1,268,620	1,328,967	1,511,606
52						
53	**Subtotal**		**3,365,525**	**3,361,943**	**3,614,929**	**3,990,632**
54			0	0	0	0
55	Capital		537,607	0	556,938	724,306
56	Misc. A/R		0	0	0	0
57	Truck		5,609	0	0	0
58	OH. Labor(Vac,Hol,Sick,Funeral,Sup		323,568	0	298,015	370,762
59						
60	**Total**		**4,232,309**	**3,361,943**	**4,469,882**	**5,085,700**

Citizens' Electric Company of Lewisburg
Rate Case with Fully Projected Future Test Y
Workpaper 1 to Schedule C
Historic and Forecast O&M
Years 2013-2026

Line	Account	Acct No	2023 Labor	2024 Labor	2025 Labor	2026 Labor	2023 OH	2024 OH	2025 OH	2026 OH
34										
35	Administrative	920	351,801	323,420	341,855	419,064	391,193	368,269	390,975	465,884
36	Misc Admin	921								
37	Misc Admin- Travel	921.1								
38	Misc Admin- Comm	921.2								
39	Misc Admin- Call Center	921.3								
40	Misc Admin- Transp	921.4								
41	Outside Services	923								
42	Property Insurance	924								
43	Injury & Damage Exp	925	0	0	0	0				
44	CEO Insurance	926.01								
45	Benefits	926.00								
46	Reg Commission Exp	928								
47	General Advertising	930.1								
48	Misc. General Exp	930.2								
49	Director's Committee	930.3								
50	Misc. General Plant	932.4	47,569	62,272	64,116	65,438	50,741	68,714	73,329	72,750
51	Total General Labor		399,370	385,692	405,971	484,503	441,934	436,983	464,304	538,634
52										
53	**Subtotal**		**1,079,671**	**1,019,861**	**1,123,224**	**1,219,649**	**1,197,394**	**1,239,081**	**1,284,618**	**1,355,914**
54										
55	Capital		537,607		556,938	570,902	0	0	0	0
56	Misc. A/R		0		0	0	0	0	0	0
57	Truck		5,609		0	0	0	0	0	0
58	OH. Labor(Vac,Hol,Sick,Funeral,Sup		323,568		298,015	370,762				
59										
60	**Total**		**1,946,455**	**1,019,861**	**1,978,177**	**2,161,313**	**1,197,394**	**1,239,081**	**1,284,618**	**1,355,914**

Citizens' Electric Company of Lewisburg
Rate Case with Fully Projected Future Test Y
Workpaper 1 to Schedule C
Historic and Forecast O&M
Years 2013-2026

Line	Account	Acct No	2023 Transp	2024 Transp	2025 Transp	2026 Transp	2023 Material	2024 Material	2025 Material	2026 Material
34										
35	Administrative	920		9,143						
36	Misc Admin	921					(37,543)	15,396	6,199	6,385
37	Misc Admin- Travel	921.1					20,548	7,817	10,000	10,300
38	Misc Admin- Comm	921.2					32,667	40,255	34,014	35,035
39	Misc Admin- Call Center	921.3					77,386	82,455	85,379	87,940
40	Misc Admin- Transp	921.4					9,655		11,267	11,605
41	Outside Services	923					47,103	40,008	37,000	38,110
42	Property Insurance	924					11,431	11,190	11,059	11,059
43	Injury & Damage Exp	925	0	0	0	0	27,561	27,341	28,907	28,907
44	CEO Insurance	926.01					(8,321)	(5,885)	0	0
45	Benefits	926.00					14,525	13,382	8,500	8,755
46	Reg Commission Exp	928					105,515	70,128	88,208	108,889
47	General Advertising	930.1					1,061	655	1,000	1,030
48	Misc. General Exp	930.2					89,888	93,095	94,112	96,935
49	Director's Committee	930.3					14,352	16,850	15,779	16,252
50	Misc. General Plant	932.4	56	76	0	0	23,548	24,039	27,267	27,267
51	Total General Labor		56	9,219	0	0	429,375	436,726	458,692	488,470
52										
53	**Subtotal**		**101,038**	**87,328**	**88,638**	**120,509**	**987,422**	**1,015,673**	**1,118,449**	**1,294,560**
54										
55	Capital		0		0	153,404				
56	Misc. A/R		0		0	0				
57	Truck									
58	OH. Labor(Vac,Hol,Sick,Funeral,Sup									
59										
60	**Total**		**101,038**	**87,328**	**88,638**	**273,913**	**987,422**	**1,015,673**	**1,118,449**	**1,294,560**

WP1_D (R **Citizens' Electric Company of Lewisburg**
Rate Case with Fully Projected Future Test Year 2026 (R)
Workpaper 1 to Schedule D
Components of Capital Projects- Zero Load Analysis
HY 2024

	POLEs			OVERHEAD CONDUCTORS			UNDERGROUND CONDUCTORS		
	Category	Amounts	% of Total	Category	Amounts	% of Total	Category	Amounts	% of Total
		Summary			Summary			Summary	
Line	Pole	Total $	%	OH Conductor	Total $	%	UG Conductor	Total $	%
1	Labor	15,418.69	35.40%	Labor	67,085.33	33.98%	Labor	30,815.31	19.98%
2	Overheads	16,706.14	38.35%	Overheads	77,821.32	39.42%	Overheads	33,350.61	21.62%
3	Transportation	7,439.13	17.08%	Transportation	17,919.28	9.08%	Transportation	6,100.55	3.96%
4	Materials	3,996.44	9.17%	Materials	34,599.45	17.53%	Materials	83,957.54	54.44%
5	Totals	43,560.40	100.00%	Totals	197,425.38	100.00%	Totals	154,224.01	100.00%
6									
7	Work Order 202006-PR02- Pole			Work Order 20200102- OH Cond			Work Order 20210101- UG Cond		
8	CECO Replace R-74-1			Rt 15 Reconductor - Wyndham Hills OH			Linntown UG - 2021		
9	Labor	2,852.13	36.53%	Labor	41,542.49	35.71%	Labor	17,396.97	14.93%
10	Overheads	3,176.38	40.68%	Overheads	44,088.52	37.90%	Overheads	17,784.44	15.26%
11	Transportation	755.20	9.67%	Transportation	11,890.79	10.22%	Transportation	3,534.87	3.03%
12	Materials	1,024.80	13.12%	Materials	18,805.99	16.17%	Materials	77,798.20	66.77%
13	Totals	7,808.51	100.00%	Totals	116,327.79	100.00%	Totals	116,514.48	100.00%
14									
15	Work Order 20201201- Pole			Work Order 20210102- OH Cond			Work Order 20201001- UG Cond		
16	CECO Replace Pole			Wolfland Rd Relocation			Svc Upgrade K-35-FR		
17	Labor	1,407.81	19.56%	Labor	9,630.79	30.07%	Labor	3,163.69	37.64%
18	Overheads	1,114.70	15.49%	Overheads	15,325.83	47.86%	Overheads	3,169.10	37.71%
19	Transportation	3,889.27	54.04%	Transportation	1,333.26	4.16%	Transportation	404.76	4.82%
20	Materials	785.14	10.91%	Materials	5,733.13	17.90%	Materials	1,666.58	19.83%
21	Totals	7,196.92	100.00%	Totals	32,023.01	100.00%	Totals	8,404.13	100.00%
22									
23	Work Order 2021-RJP07- Pole			Work Order 20200401- OH Cond (3ph Ext)			Work Order 20210407- UG Cond		
24	CECO Replace T-19-14-14			3ph Ext from T-19-14-17-3-2			New Svc to 285 Sunnyside Dr		
25	Labor	1,629.13	35.74%	Labor	9,239.95	32.58%	Labor	839.56	33.79%
26	Overheads	1,989.91	43.66%	Overheads	10,295.25	36.31%	Overheads	1,019.93	41.05%
27	Transportation	366.08	8.03%	Transportation	3,197.41	11.28%	Transportation	103.54	4.17%
28	Materials	572.55	12.56%	Materials	5,624.67	19.84%	Materials	521.69	21.00%
29	Totals	4,557.67	100.00%	Totals	28,357.28	100.00%	Totals	2,484.72	100.00%

WP1_D (R **Citizens' Electric Company of Lewisburg**
Rate Case with Fully Projected Future Test Year 2026 (R)
Workpaper 1 to Schedule D
Components of Capital Projects- Zero Load Analysis
HY 2024

	POLEs			OVERHEAD CONDUCTORS			UNDERGROUND CONDUCTORS		
	Category	Amounts	% of Total	Category	Amounts	% of Total	Category	Amounts	% of Total
30									
31	Work Order 20210204- Pole			Work Order 20210509-OH Cond (1 Ph Ext)			Work Order 20200110- UG Cond (1ph Ext)		
32	Replace Burnt Pole U-92			Svc to Construction Trailer			Svc Ext from U-197		
33	Labor	7,155.07	41.53%	Labor	1,585.96	30.87%	Labor	5,635.60	32.83%
34	Overheads	7,954.77	46.17%	Overheads	1,926.68	37.51%	Overheads	6,528.18	38.03%
35	Transportation	1,308.17	7.59%	Transportation	271.39	5.28%	Transportation	1,669.10	9.72%
36	Materials	811.07	4.71%	Materials	1,352.99	26.34%	Materials	3,331.80	19.41%
37	Totals	17,229.08	100.00%	Totals	5,137.02	100.00%	Totals	17,164.68	100.00%
38									
39	Work Order 20210501- Pole			Work Order 20210901- OH Cond			Work Order 20210409- UG Cond		
40	Pole Hit - Grove Road @ R-251-11-3-5-9			New pole & 3ph Svc			OH to UG Reloc 30 S 17th		
41	Labor	1,405.61	33.77%	Labor	4,626.24	32.55%	Labor	784.30	38.66%
42	Overheads	1,489.95	35.80%	Overheads	5,627.49	39.60%	Overheads	1,042.90	51.41%
43	Transportation	825.90	19.84%	Transportation	1,062.19	7.47%	Transportation	57.98	2.86%
44	Materials	440.58	10.59%	Materials	2,895.63	20.38%	Materials	143.32	7.07%
45	Totals	4,162.04	100.00%	Totals	14,211.55	100.00%	Totals	2,028.50	100.00%
46									
47	Work Order 20220101- Pole			Work Order 20210503- OH Cond			Work Order 20211104- UG Cond		
48	New SL V-8-40-5 - 125 Paul L			New Svc to Garage 7028 Old Turnpike			Repl Failed UG Svc - 34 James Rd		
49	Labor	968.94	37.18%	Labor	459.90	33.60%	Labor	2,995.19	39.27%
50	Overheads	980.43	37.62%	Overheads	557.55	40.73%	Overheads	3,806.06	49.90%
51	Transportation	294.51	11.30%	Transportation	164.24	12.00%	Transportation	330.30	4.33%
52	Materials	362.30	13.90%	Materials	187.04	13.67%	Materials	495.95	6.50%
53	Totals	2,606.18	100.00%	Totals	1,368.73	100.00%	Totals	7,627.50	100.00%

WP2_B (R) **Citizens' Electric Company of Lewisburg**
Rate Case with Fully Projected Future Test Year 2026 (R)
Workpaper 2 to Schedule B
Monthly Billing Units, Rates And Revenue
Historic Year 2024

Line		Residential	Space Heating	GLP-1	GLP-3	Municipal Boulevard Lighting	Outdoor Lighting	Total
1				**BILLING UNITS**				
2				**kWh Sales HY 2024**				
3	Jan-24	0	0	0	0	0	0	0
4	Feb-24	0	0	0	0	0	0	0
5	Mar-24	0	0	0	0	0	0	0
6	Apr-24	0	0	0	0	0	0	0
7	May-24	9,326,803	14,243	2,354,786	3,269,055	8,406	22,707	14,996,000
8	Jun-24	9,611,387	21,004	2,572,235	3,446,627	8,218	19,391	15,678,862
9	Jul-24	7,494,805	16,508	2,145,350	3,094,532	6,773	18,814	12,776,782
10	Aug-24	6,769,432	11,348	2,024,504	3,201,539	6,485	16,013	12,029,321
11	Sep-24	5,134,716	6,125	1,784,039	3,361,237	5,577	14,672	10,306,366
12	Oct-24	5,526,480	2,591	1,992,971	4,022,367	4,995	12,662	11,562,066
13	Nov-24	6,716,368	2,758	2,308,526	3,884,948	4,363	13,858	12,930,821
14	Dec-24	6,806,209	2,828	2,377,930	4,394,580	4,709	15,354	13,601,610
15		57,386,200	77,405	17,560,341	28,674,885	49,526	133,471	103,881,828
16		*24,071,453*	*0*	*22,127,425*	*31,315,918*	*2,372,941*	*34,989,200*	*0*
17				**Full Month Customers HY 2024**				
18	Jan-24	5,944	2	1,119	41	12	24	7,142
19	Feb-24	5,941	4	1,128	40	13	27	7,153
20	Mar-24	5,942	4	1,129	40	13	27	7,155
21	Apr-24	5,944	4	1,130	40	13	26	7,157
22	May-24	5,946	4	1,133	39	13	26	7,161
23	Jun-24	5,949	4	1,128	39	13	26	7,159
24	Jul-24	5,964	4	1,128	39	13	26	7,174
25	Aug-24	5,965	3	1,130	39	13	26	7,176
26	Sep-24	5,975	3	1,132	40	13	26	7,189
27	Oct-24	5,990	3	1,134	40	13	26	7,206
28	Nov-24	6,001	3	1,134	40	13	26	7,217
29	Dec-24	6,001	3	1,137	40	13	26	7,220
30	Annual Bills	71,562	41	13,562	477	155	312	86,109
31	Average Monthly Bills	5,964	3	1,130	40	13	26	7,176
32								

WP2_B (R) **Citizens' Electric Company of Lewisburg**
Rate Case with Fully Projected Future Test Year 2026 (R)
Workpaper 2 to Schedule B
Monthly Billing Units, Rates And Revenue
Historic Year 2024

Line		Residential	Space Heating	GLP-1	GLP-3	Municipal Boulevard Lighting	Outdoor Lighting	Total
33					**Monthly Billing Units- Public Lighting and Street Lighting HY 2024**			
34	Rate 1				MBL- Meter Coun	13		
35	Rate 2				MBL- Post Count	535		
36	Rate 3				Mth revenue	$2,179.22	$9,602.01	
37					**RATES AND CHARGES**			
38					**Tariff Rates**			
39	Customer Charge	$13.10	$20.19	$16.00	$55.00	$3.84		
40						MBL- Meter		
41								
42						MBL- Post	Average	
43	Energy Block 1	$0.033680	$0.044130	$0.009630	$0.009490	$3.98	$14.66	
44								
45	Energy Block 2				$0.001030		Count	
46							655	
47	Reservation Chge				$2.51			
48								
49	Voltage Discount				($0.234420)			
50	Block 1 kWh				3,500			
51	Demand Block 1			$3.74	$5.37			
52								
53	Block 1 Energy = Demand X				30			
54	GSSR Rate	$0.086970	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	
55								
56	STAS Rate	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	
57								

WP2_B (R) **Citizens' Electric Company of Lewisburg**
Rate Case with Fully Projected Future Test Year 2026 (R)
Workpaper 2 to Schedule B
Monthly Billing Units, Rates And Revenue
Historic Year 2024

Line		Residential	Space Heating	GLP-1	GLP-3	Municipal Boulevard Lighting	Outdoor Lighting	Total
58				**COMPUTATION OF REVENUE**				
59				**Customer Charge Revenue- Full Month Customers**				
60	Jan-24	$77,866	$40	$17,904	$2,255	$2,179	$9,602	$109,847
61	Feb-24	77,827	81	18,048	2,200	2,179	9,602	109,937
62	Mar-24	77,840	81	18,064	2,200	2,179	9,602	109,966
63	Apr-24	77,866	81	18,080	2,200	2,179	9,602	110,008
64	May-24	77,893	81	18,128	2,145	2,179	9,602	110,028
65	Jun-24	77,932	81	18,048	2,145	2,179	9,602	109,987
66	Jul-24	78,128	81	18,048	2,145	2,179	9,602	110,183
67	Aug-24	78,142	61	18,080	2,145	2,179	9,602	110,208
68	Sep-24	78,273	61	18,112	2,200	2,179	9,602	110,426
69	Oct-24	78,469	61	18,144	2,200	2,179	9,602	110,655
70	Nov-24	78,613	61	18,144	2,200	2,179	9,602	110,799
71	Dec-24	78,613	61	18,192	2,200	2,179	9,602	110,847
72		$937,462	$828	$216,992	$26,235	$26,151	$115,224	$1,322,892
73								
74				**Distribution kWh Revenue**				
75	Jan-24	$0	$0	$0	$2,292			$2,292
76	Feb-24	0	0	0	2,230			2,230
77	Mar-24	0	0	0	2,156			2,156
78	Apr-24	#VALUE!	#VALUE!	#VALUE!	2,245			#VALUE!
79	May-24	314,127	629	22,677	5,848			343,280
80	Jun-24	323,712	927	24,771	6,914			356,323
81	Jul-24	252,425	728	20,660	5,864			279,677
82	Aug-24	227,994	501	19,496	6,614			254,606
83	Sep-24	172,937	270	17,180	6,437			196,824
84	Oct-24	186,132	114	19,192	6,682			212,121
85	Nov-24	226,207	122	22,231	7,214			255,774
86	Dec-24	229,233	125	22,899	6,829			259,087
87		#VALUE!	#VALUE!	#VALUE!	$61,326	$0	$0	#VALUE!
88								
89				**Distribution Demand Revenue (Includes Voltage Discount and Reservation Chge)**				
90	Jan-24			$51,702	$60,300			$112,003
91	Feb-24			54,284	57,502			111,786
92	Mar-24			51,684	55,671			107,356
93	Apr-24			51,106	59,269			110,375
94	May-24			50,751	66,251			117,002
95	Jun-24			49,982	75,162			125,144
96	Jul-24			51,519	70,553			122,072
97	Aug-24			50,183	79,012			129,195
98	Sep-24			50,109	73,342			123,451
99	Oct-24			48,431	67,013			115,444
100	Nov-24			50,090	72,519			122,609
101	Dec-24			51,971	63,333			115,304
102		$0	$0	$611,814	$799,927	$0	$0	$1,411,741
103								
104								

WP2_B (R) **Citizens' Electric Company of Lewisburg**
Rate Case with Fully Projected Future Test Year 2026 (R)
Workpaper 2 to Schedule B
Monthly Billing Units, Rates And Revenue
Historic Year 2024

Line		Residential	Space Heating	GLP-1	GLP-3	Municipal Boulevard Lighting	Outdoor Lighting	Total
105		**Total Revenue**						
106	Jan-24	$77,866	$40	$69,606	$64,847	$2,179	$9,602	$224,141
107	Feb-24	77,827	81	72,332	61,931	2,179	9,602	223,953
108	Mar-24	77,840	81	69,748	60,027	2,179	9,602	219,478
109	Apr-24	#VALUE!	#VALUE!	#VALUE!	63,714	2,179	9,602	#VALUE!
110	May-24	392,019	709	91,556	74,244	2,179	9,602	570,310
111	Jun-24	401,643	1,008	92,800	84,221	2,179	9,602	591,454
112	Jul-24	330,553	809	90,227	78,561	2,179	9,602	511,932
113	Aug-24	306,136	561	87,759	87,771	2,179	9,602	494,009
114	Sep-24	251,210	331	85,401	81,979	2,179	9,602	430,702
115	Oct-24	264,601	175	85,768	75,895	2,179	9,602	438,220
116	Nov-24	304,820	182	90,465	81,933	2,179	9,602	489,182
117	Dec-24	307,846	185	93,062	72,363	2,179	9,602	485,238
118		#VALUE!	#VALUE!	#VALUE!	$887,487	$26,151	$115,224	#VALUE!
119								
120		**BILLING UNITS- DETAIL**						
121		**Block 1 kWh Sales HY 2024**						
122	Jan-24	0	0	0	270,900	0	0	270,900
123	Feb-24	0	0	0	263,544	0	0	263,544
124	Mar-24	0	0	0	254,825	0	0	254,825
125	Apr-24	RS	SH	GLP-1	265,394	MBL	POL	265,394
126	May-24	9,326,803	14,243	2,354,786	293,293	8,406	22,707	12,020,238
127	Jun-24	9,611,387	21,004	2,572,235	397,633	8,218	19,391	12,629,868
128	Jul-24	7,494,805	16,508	2,145,350	316,351	6,773	18,814	9,998,601
129	Aug-24	6,769,432	11,348	2,024,504	392,062	6,485	16,013	9,219,844
130	Sep-24	5,134,716	6,125	1,784,039	351,601	5,577	14,672	7,296,730
131	Oct-24	5,526,480	2,591	1,992,971	300,150	4,995	12,662	7,839,849
132	Nov-24	6,716,368	2,758	2,308,526	379,765	4,363	13,858	9,425,638
133	Dec-24	6,806,209	2,828	2,377,930	272,222	4,709	15,354	9,479,252
134		57,386,200	77,405	17,560,341	3,757,740	49,526	133,471	78,964,683
135		5,667,038	2,815	2,112,686	*3,757,740*			
136		**Block 2 kWh Sales HY 2024**						
137	Jan-24				(270,900)			(270,900)
138	Feb-24				(263,544)			(263,544)
139	Mar-24				(254,825)			(254,825)
140	Apr-24				(265,394)			(265,394)
141	May-24				2,975,762			2,975,762
142	Jun-24				3,048,994			3,048,994
143	Jul-24				2,778,181			2,778,181
144	Aug-24				2,809,477			2,809,477
145	Sep-24				3,009,636			3,009,636
146	Oct-24				3,722,217			3,722,217
147	Nov-24				3,505,183			3,505,183
148	Dec-24				4,122,358			4,122,358
149		0	0	0	24,917,145	0	0	24,917,145
150								103,881,828

WP2_B (R) **Citizens' Electric Company of Lewisburg**
Rate Case with Fully Projected Future Test Year 2026 (R)
Workpaper 2 to Schedule B
Monthly Billing Units, Rates And Revenue
Historic Year 2024

Line		Residential	Space Heating	GLP-1	GLP-3	Municipal Boulevard Lighting	Outdoor Lighting	Total
151		GLP-1 Month	GLP-1 Excess	GLP-1 Month	**GLP-3**			
152	Jan-24	13,824		13,824	9,158			
153	Feb-24	14,515		14,515	8,539			
154	Mar-24	13,819		13,819	8,204			
155	Apr-24	13,665		13,665	8,930			
156	May-24	13,570		13,570	10,675			
157	Jun-24	13,364		13,364	13,578			
158	Jul-24	13,775		13,775	11,670			
159	Aug-24	13,418		13,418	14,187			
160	Sep-24	13,398		13,398	12,430			
161	Oct-24	12,950		12,950	10,849			
162	Nov-24	13,393		13,393	13,250			
163	Dec-24	13,896		13,896	9,756			
164		163,587	0	163,587	131,225			
165		*163,587*			*131,225*			
166								
167		GLP3 kWH		GLP3 kW	GLP3 Volt Disc	GLP3 Res Chge	GLP3 Total	GLP3 kWVD
168								
169	Jan-24	0		49,177	(1,101)	12,225	60,300	4,697
170	Feb-24	0		45,852	(900)	12,550	57,502	3,841
171	Mar-24	0		44,054	(885)	12,502	55,671	3,774
172	Apr-24	0		47,953	(1,041)	12,357	59,269	4,440
173	May-24	3,269,055		57,322	(1,200)	10,128	66,251	5,119
174	Jun-24	3,446,627		72,912	(1,240)	3,490	75,162	5,289
175	Jul-24	3,094,532		62,670	(1,294)	9,177	70,553	5,520
176	Aug-24	3,201,539		76,187	(1,339)	4,165	79,012	5,713
177	Sep-24	3,361,237		66,747	(1,305)	7,899	73,342	5,566
178	Oct-24	4,022,367		58,261	(1,208)	9,960	67,013	5,153
179	Nov-24	3,884,948		71,152	(1,147)	2,514	72,519	4,894
180	Dec-24	4,394,580		52,392	(1,163)	12,104	63,333	4,960
181		28,674,885		704,679	(13,822)	109,071	799,927	58,964
182		4,289,595						*58,964*
183					In GLP-RTP	5,000		
184						12,550		

WP2_B (R) **Citizens' Electric Company of Lewisburg**
Rate Case with Fully Projected Future Test Year 2026 (R)
Workpaper 2 to Schedule B
Monthly Billing Units, Rates And Revenue
Historic Year 2024

Line		Residential	Space Heating	GLP-1	GLP-3	Municipal Boulevard Lighting	Outdoor Lighting	Total
185		GLP3	GLP3 - Customer	GLP3 - EvH	GLP3 - Customer	Res Charge BU		ResCredit
186		kWh	kWh	kWh	kWh	$		$
187	Jan-24	0	0	0	130	12,550		(325)
188	Feb-24	0	0	0	0	12,550		0
189	Mar-24	0	0	0	38	12,550		(48)
190	Apr-24	0	0	0	116	12,550		(193)
191	May-24	1,443,384	181,071	1,644,600	13,665	12,550		(2,422)
192	Jun-24	1,601,576	179,451	1,665,600	315,335	12,550		(9,060)
193	Jul-24	1,401,164	169,968	1,523,400	17,624	12,550		(3,373)
194	Aug-24	1,338,292	185,047	1,678,200	99,034	12,550		(8,385)
195	Sep-24	1,302,840	198,997	1,859,400	83,331	12,550		(4,651)
196	Oct-24	1,360,328	521,839	2,140,200	25,988	12,550		(2,590)
197	Nov-24	1,418,116	232,432	2,234,400	201,907	12,550		(10,036)
198	Dec-24	1,590,908	336,472	2,467,200	431	12,550		(446)
199		11,456,608	2,005,277	15,213,000	757,598	150,600		(41,529)
200		1,722,316	310,627	2,485,800	*757,598*	*150,600*		(41,529)
201								($2.51)
202								

203	Watts per Lamp		200	130	500	100	280	300.95
204	**POL kWh**	**Hours**	175 W MV kWh/Month	100 W HPS kWh/Month	400 W HPS kWh/Month	5K LED kWh/Month	15K LED kWh/Month	20K LED kWh/Month
205	Jan-24	440	88	57	220	44	123	132
206	Feb-24	370	74	48	185	37	104	111
207	Mar-24	370	74	48	185	37	104	111
208	Apr-24	310	62	40	155	31	87	93
209	May-24	285	57	37	143	29	80	86
210	Jun-24	250	50	33	125	25	70	75
211	Jul-24	275	55	36	138	28	77	83
212	Aug-24	305	61	40	153	31	85	92
213	Sep-24	335	67	44	168	34	94	101
214	Oct-24	395	79	51	198	40	111	119
215	Nov-24	415	83	54	208	42	116	125
216	Dec-24	450	90	59	225	45	126	135
217		4,200	840	546	2,100	420	1,176	1,264
218								
219	POL Lamps	655	56	37	3	514	27	18
220								

WP2_B (R) **Citizens' Electric Company of Lewisburg**
Rate Case with Fully Projected Future Test Year 2026 (R)
Workpaper 2 to Schedule B
Monthly Billing Units, Rates And Revenue
Historic Year 2024

Line			Residential	Space Heating	GLP-1	GLP-3	Municipal Boulevard Lighting	Outdoor Lighting	Total
221	Description	Device	Count	Dist	Tariff Total			Gen	
222	OL 175W MV OH Open	22	49	$7.27	$13.36	Device Type: 22-OL 175W MV OH Open		$6.09	
223	OL 175W MV UG Cobra	23	7	$14.77	$20.86	Device Type: 23-OL 175W MV UG Color		$6.09	
224	OL 100W HPS OH	26	24	$9.09	$13.05	Device Type: 26-OL 100W HPS OH Oper		$3.96	
225	OL 100W HPS UG	27	13	$14.77	$18.73	Device Type: 27-OL 100W HPS UG Oper		$3.96	
226	OL 100W HPS Colonial	28	0	$21.88	$25.84			$3.96	
227	OL 400W HPS OH Cobra	31	3	$14.20	$28.35	Device Type: 31-OL 400W HPS OH Cobr		$14.15	
228	OL 400WHPS UG Cobra	34	0						
229									
230	LED 15K Lum OH Cobra	40	23	$16.25	$20.51	Device Type: 40-OL LED 15k Lum OH C		$4.26	
231	LED 5K Lum OH Cobra	41	409	$12.92	$14.29	Device Type: 41-OL LED 5k LUM,OH Cc		$1.37	
232	LED 5K Lum UG Colonia	42	76	$26.60	$28.12	Device Type: 42-OL LED 5k LUM UG Cc		$1.52	
233	LED 5K Lum UG Cobra	43	29	$18.84	$20.21	Device Type: 43-OL LED 5k LUM UG Cc		$1.37	
234	LED 20K Lum OH Cobra	44	17	$20.51	$29.03	Device Type: 44-OL LED 20K LUM,OH (		$8.52	
235	LED 20K Lum UG Cobra	45	1	$26.40	$34.92			$8.52	
236	LED 15K Lum UG Cobra	46	4	$22.14	$26.40	Device Type: 46-OL LED 15k LUM UG C		$4.26	
237	OL 400W HPS UG								
238	OL 100W JPS UG								
239			655	$ 9,602	Monthly	LED	104,275		
240				$14.66	Average rate	MV-HPS	10,949		
241				$ 115,224	Annual		115,224		

WP2_C (R) **Citizens' Electric Company of Lewisburg**
Rate Case with Fully Projected Future Test Year 2026 (R)
Workpaper 2 to Schedule C
Accumulated Deferred Income Taxes
Years 2024 through 2026

Line	CECO	HY 2024	FTY 2025	FPFTY 2026
1				
2	Book	15,229,320	16,666,142	18,189,781
3				
4	Federal Tax - MACRS	22,869,678	23,985,289	25,240,900
5				
6	Federal Tax - SL	21,209,863	22,378,980	23,637,765
7				
8	PA Tax	19,003,820	20,281,631	21,680,887
9				
10	Federal Tax Depr Exp - MACRS	945,688	1,115,611	1,255,610
11				
12	Federal Tax Depr Exp - SL	1,042,603	1,169,116	1,258,785
13				
14	PA Tax Depr Exp	1,255,863	1,277,811	1,399,256
15				

WP2_D (R)

Citizens' Electric Company of Lewisburg
Rate Case with Fully Projected Future Test Year 2026 (R)
Workpaper 2 to Schedule D
Transformer Costs and Replacements
HY 2024

Line	Configure	kV Rating	Phase Code	Count	Replace-ment
1	OH 1Ph	**5**	1	5	TPM15
2	OH 1Ph	**10**	1	189	TPM15
3	OH 1Ph	**15**	1	509	TPM15
4	OH 1Ph	**25**	1	602	TPM25
5	OH 1Ph	**37.5**	1	73	TPM50
6	OH 1Ph	**50**	1	426	TPM50
7	OH 1Ph	**75**	1	27	TPM100
8	OH 1Ph	**100**	1	88	TPM100
9	OH 1Ph	**167**	1	14	TPM167
10					
11	UG 1Ph	**15**	4	10	TPD25
12	UG 1Ph	**25**	4	237	TPD25
13	UG 1Ph	**50**	4	351	TPD50
14	UG 1Ph	**100**	4	35	TPD100
15					
16	UG 3Ph	**150**	5	9	TPD150
17	UG 3Ph	**300**	5	10	TPD300
18	UG 3Ph	**500**	5	8	TPD500
19	UG 3Ph	**750**	5	1	TPD1000
20	UG 3Ph	**1000**	5	7	TPD1000
21	UG 3Ph	**1500**	5	1	TPD1500
22				2,602	
23		*Check=*		*2,602*	
24					

WP2_D (R) **Citizens' Electric Company of Lewisburg**
Rate Case with Fully Projected Future Test Year 2026 (R)
Workpaper 2 to Schedule D
Transformer Costs and Replacements
HY 2024

	Type	Count	Unit Cost	Total Cost	Matl Cost	Labor	OH	Truck
26	TPM15	703	$ 1,164	817,963	$ 812	$ 135.89	$ 154.77	$ 60.87
27	TPM25	602	$ 1,740	1,047,198	$ 1,388	$ 135.89	$ 154.77	$ 60.87
28	TPM50	499	$ 2,385	1,189,882	$ 2,033	$ 135.89	$ 154.77	$ 60.87
29	TPM100	115	$ 4,040	464,546	$ 3,688	$ 135.89	$ 154.77	$ 60.87
30	TPM167	14	$ 4,850	67,893	$ 4,498	$ 135.89	$ 154.77	$ 60.87
31								
32	TPD25	247	$ 2,964	732,187	$ 2,230	$ 271.79	$ 309.55	$ 152.99
33	TPD50	351	$ 3,642	1,278,454	$ 2,908	$ 271.79	$ 309.55	$ 152.99
34	TPD50 /4		$ 911					
35	TPD100	35	$ 4,822	168,781	$ 4,088	$ 271.79	$ 309.55	$ 152.99
36	TPD150	9	$ 12,422	111,801	$ 11,688	$ 271.79	$ 309.55	$ 152.99
37	TPD300	10	$ 16,622	166,223	$ 15,888	$ 271.79	$ 309.55	$ 152.99
38	TPD500	8	$ 17,289	138,315	$ 16,555	$ 271.79	$ 309.55	$ 152.99
39	TPD1000	8	$ 28,734	229,875	$ 28,000	$ 271.79	$ 309.55	$ 152.99
40	TPD1500	1	$ 32,734	32,734	$ 32,000	$ 271.79	$ 309.55	$ 152.99
41		2,602		6,445,853				
42								

WP3_B (R) **Citizens' Electric Company of Lewisburg**
Rate Case with Fully Projected Future Test Year 2026 (R)
Workpaper 3 to Schedule B
Monthly Customers
Historic Year 2024

Line		RS	RSH	RSD	RSHD	RS Total	GLP1	GLP1D	GLP1 Total	SYL OL	MBL	SH
1	1/1/2024	3,166		2,778		5,944	1,119		1,119	24	12	2
2	2/1/2024	3,137		2,804		5,941	1,128		1,128	27	13	4
3	3/1/2024	3,137		2,805		5,942	1,129		1,129	27	13	4
4	4/1/2024	3,133		2,811		5,944	1,130		1,130	26	13	4
5	5/1/2024	3,133		2,813		5,946	1,133		1,133	26	13	4
6	6/1/2024	3,137		2,812		5,949	1,128		1,128	26	13	4
7	7/1/2024	3,137		2,827		5,964	1,128		1,128	26	13	4
8	8/1/2024	3,138		2,827		5,965	1,130		1,130	26	13	3
9	9/1/2024	3,138		2,837		5,975	1,132		1,132	26	13	3
10	10/1/2024	3,140		2,850		5,990	1,134		1,134	26	13	3
11	11/1/2024	3,141		2,860		6,001	1,134		1,134	26	13	3
12	12/1/2024	3,142		2,859		6,001	1,137		1,137	26	13	3
13	Total Bills	37,679	-	33,883	-	71,562	13,562	-	13,562	312	155	41
14												
15												

16		GLP3	GLP3D	GLP5D	GLPPD	G3B	G3D	GLP3 Total	Total	Check
17	1/1/2024	37			4			41	7,142	7,142
18	2/1/2024	33			7			40	7,153	7,153
19	3/1/2024	33			7			40	7,155	7,155
20	4/1/2024	34			6			40	7,157	7,157
21	5/1/2024	33			6			39	7,161	7,161
22	6/1/2024	33			6			39	7,159	7,159
23	7/1/2024	33			6			39	7,174	7,174
24	8/1/2024	33			6			39	7,176	7,176
25	9/1/2024	34			6			40	7,189	7,189
26	10/1/2024	34			6			40	7,206	7,206
27	11/1/2024	34			6			40	7,217	7,217
28	12/1/2024	34			6			40	7,220	7,220
29	Total Bills	405	-	-	72	-	-	477	86,109	86,109

WP3_D (R **Citizens' Electric Company of Lewisburg**
Rate Case with Fully Projected Future Test Year 2026 (R)
Workpaper 3 to Schedule D
Services Costs
HY 2024

Line	Volt	OHUG	Phase	RS	RSH	SH	GLP1	GLP1D	GLP3	MBL	Inactive	Total
1	SEC	OH	1	2,313	1,091	2	572	11	5	2	44	4,040
2	SEC	OH	3	11	6	1	96	7	5	-	4	130
3	SEC	UG	1	805	1,615	-	292	13	-	11	24	2,760
4	SEC	UG	3	2	105	-	128	11	27	-	2	275
5	PRI	OH	1	-	-	-	-	-	-	-	-	-
6	PRI	OH	3	-	-	-	-	-	5	-	-	5
7	PRI	UG	1	-	-	-	-	-	-	-	-	-
8	PRI	UG	3	-	-	-	1	-	1	-	2	4
9				3,131	2,817	3	1,089	42	43	13	76	7,214
10												7,214

11	Class	Volt	Volt	Phase	Count	Material/ Labor	Truck Hours	Truck	Total Cost	Total Cost
12	Res	SEC	OH	1	3,404	$ 753.34	2.8	$ 86.90	$ 840.24	$ 2,860,177
13	Res	SEC	OH	3	17	$ 869.61	3.5	$ 106.07	$ 975.68	$ 16,587
14	Res	SEC	UG	1	2,420	$ 937.53	3.3	$ 101.21	$ 1,038.74	$ 2,513,751
15	Res	SEC	UG	3	107	$ 1,062.03	4.0	$ 122.68	$ 1,184.71	$ 126,764
16	SH	SEC	OH	1	2	$ 753.34	2.8	$ 86.90	$ 840.24	$ 1,680
17	SH	SEC	OH	3	1	$ 869.61	3.5	$ 106.07	$ 975.68	$ 976
18	SH	SEC	UG	1	-	$ 937.53	3.3	$ 101.21	$ 1,038.74	$ -
19	SH	SEC	UG	3	-	$ 1,062.03	4.0	$ 122.68	$ 1,184.71	$ -
20	GLP1	SEC	OH	1	583	$ 753.34	2.8	$ 86.90	$ 840.24	$ 489,860
21	GLP1	SEC	UG	3	103	$ 869.61	3.5	$ 106.07	$ 975.68	$ 100,495
22	GLP1	SEC	OH	1	305	$ 937.53	3.3	$ 101.21	$ 1,038.74	$ 316,816
23	GLP1	SEC	UG	3	139	$ 1,062.03	4.0	$ 122.68	$ 1,184.71	$ 164,675
24	GLP3	SEC	UG	1	5	$ 753.34	2.8	$ 86.90	$ 840.24	$ 4,201
25	GLP3	SEC	OH	3	5	$ 869.61	3.5	$ 106.07	$ 975.68	$ 4,878
26	GLP3	SEC	OH	1	-	$ 937.53	3.3	$ 101.21	$ 1,038.74	$ -
27	GLP3	SEC	UG	3	27	$ 1,062.03	4.0	$ 122.68	$ 1,184.71	$ 31,987
28	MBL	SEC	UG	1	2	$ 753.34	2.8	$ 86.90	$ 840.24	$ 1,680
29	MBL	SEC	OH	3	-	$ 869.61	3.5	$ 106.07	$ 975.68	$ -
30	MBL	SEC	OH	1	11	$ 937.53	3.3	$ 101.21	$ 1,038.74	$ 11,426
31	MBL	SEC	UG	3	-	$ 1,062.03	4.0	$ 122.68	$ 1,184.71	$ -
32			Active Secondary:		7,131					$ 6,645,953
33			Primary:		9					
34			*Company/ Inactive/ Future:*		76					
35					7,216					

BEFORE

THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	**:**	
	:	
v.	**:**	**Docket No. R-2025-3054394**
	:	
Citizens' Electric Company of Lewisburg, PA	**:**	

SURREBUTTAL TESTIMONY

OF

HOWARD S. GORMAN

ON BEHALF OF

CITIZENS' ELECTRIC COMPANY OF LEWISBURG, PA

AUGUST 28, 2025

BEFORE

THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	**:**	
	:	
v.	**:**	**Docket No. R-2025-3054394**
	:	
Citizens' Electric Company of Lewisburg, PA	**:**	

SURREBUTTAL TESTIMONY OF HOWARD S. GORMAN
ON BEHALF OF CITIZENS' ELECTRIC COMPANY OF LEWISBURG, PA

Q. Please state your name, occupation and business address.

A. My name is Howard Gorman. I am the President of HSG Group, Inc., a consulting firm specializing in utility rate and regulatory matters, located in Great Neck, NY.

Q. Are you the same Howard Gorman that provided Direct Testimony on behalf of Citizens' Electric Company of Lewisburg, PA ("Citizens'" or "Company")?

A. Yes. Terms defined in my Direct Testimony or my Rebuttal Testimony have the same meaning in this Surrebuttal Testimony.

Q. What is the purpose of your testimony today?

A. The purpose of my testimony is to respond to the Rebuttal Testimony of the following witnesses:

- Office of Consumer Advocate ("OCA") Witness Myer (OCA St. 1R)
- OCA Witness Deupree (OCA St. 3R)

Q. Are you sponsoring any exhibits today?

A. No.

Q. Are you supporting any changes to the Company's filing, as amended by Exhibit___(HSG-1R)?

A. No.

Q. Please summarize your review of the Rebuttal Testimony of Mr. Meyer (OCA St. 1R) and Mr. Deupree (OCA St. 3R).

A. Except for Mr. Deupree's discussion of the Company's Customer Cost Analysis, which I address immediately below, neither Mr. Meyer nor Mr. Deupree raised any new issues or provided any new arguments for their positions.

Mr. Meyer addresses two adjustments that were suggested in the Direct Testimony by other parties. Citizens' already accepted one of those adjustments (Tax Rate). I addressed the other adjustment (Unamortized Rate Case Expense) in my Rebuttal Testimony. Mr. Meyer has not raised any arguments that I have not fully refuted.

Q. What did Mr. Deupree say regarding the Company's Customer Costs Analysis?

A. Mr. Deupree repeated his objection to any increase in the monthly Customer Charges (OCA ST. 3R, p. 5). I will address the specifics of his testimony below:

- Mr. Deupree opines that the Customer Cost Analysis should be based on the Rate of Return ("ROR") at present rates of 1.46%, because the Commission has not approved its requested ROR or that of any other witness (OCA St. 3R, p. 3). This approach does not make sense. First, Mr. Deupree is implicitly accepting the Company's computation of its revenue requirement, but the Commission has not accepted that either. Second, we are establishing the rates for a Fully Projected Future Test Year assuming that a rate increase will be granted. Using the existing ROR without consideration of the rate relief is inconsistent with this process. Third, the rates and revenues currently charged

by the Company are too low, that is why a rate case was filed, so using the existing ROR only perpetuates the shortfall. What if the Company had been producing a negative ROR; would Mr. Deupree advocate using a negative ROR to set new rates?

- Mr. Deupree compared the Company's current Customer Charges to Customer-Related Costs computed using the ROR proposed by OCA Witness Walters, 7.44%; and computed that for Residential Service ("RS"), Space Heating ("SH") and General Light and Power Service ("GLP-1"), current Customer Charges recover approximately 76%, 74% and 78% of Customer-Related Costs; and therefore, in his view, there is no "pressing need to increase" them (OCA St. 3R, p. 4). For the reasons stated in my prior testimony, it is important that Customer Charges reflect costs, and this view is supported by prior guidance from the Commission, including the UGI 2017 Order, p. 173, where the Commission said, "Thus, we find that UGI's proposal is consistent with *Lloyd,* which held that rate structures should be adjusted to reflect the cost of service to each rate class and to eliminate cross-subsidization." There is no authority or rationale to substitute Mr. Deupree's judgment that the current monthly Customer Charges are "good enough" for ratemaking and economic theory and practice and the long-standing guidance of the Commission regarding the appropriate method to establish customer charges.
- Finally, Mr. D'Ascendis has explained why OCA Witness Walters' ROR recommendation is unreasonably low and not appropriate to establish rates in this proceeding.

I recommend the Commission evaluate the Company's proposed Customer charges based on the information it has filed in this case, Exhibit___(HSG-1R), and the principles which have been established by precedents.

Q. Does this conclude your Surrebuttal Testimony today?

A. Yes.

BEFORE

THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	**:**	
	:	
v.	**:**	**Docket No. R-2025-3054394**
	:	
Citizens' Electric Company of Lewisburg, PA	**:**	

REJOINDER TESTIMONY

OF

HOWARD S. GORMAN

ON BEHALF OF

CITIZENS' ELECTRIC COMPANY OF LEWISBURG, PA

September 3, 2025

BEFORE

THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	**:**	
	:	
v.	**:**	**Docket No. R-2025-3054394**
	:	
Citizens' Electric Company of Lewisburg, PA	**:**	

REJOINDER TESTIMONY OF HOWARD S. GORMAN
ON BEHALF OF CITIZENS' ELECTRIC COMPANY OF LEWISBURG, PA

Q. Please state your name and business address.

A. My name is Howard Gorman. I am the President of HSG Group, Inc., a consulting firm specializing in utility rate and regulatory matters, located in Great Neck, NY.

Q. Are you the same Howard Gorman who previously submitted Direct Testimony in this proceeding on behalf of Citizens' Electric Company of Lewisburg, PA ("Citizens'" or "Company")?

A. Yes. Terms defined in my Direct Testimony, Rebuttal Testimony or Surrebuttal Testimony have the same meaning in this Rejoinder Testimony.

Q. What is the purpose of your Rejoinder Testimony?

A. I will respond to various arguments Mr. Kevin Lucas put forth on behalf of the Solar Projects.

Q. Mr. Lucas has argued that because the Company has not shown that its costs have increased in order to serve the Solar Projects, then the Solar Projects should be excused from paying any costs of the distribution system. Please respond.

A. Mr. Lucas' argument is without merit.

First, Pennsylvania does not recognize incremental or marginal costs as the basis for distribution rates; instead, Pennsylvania recognizes embedded costs.

Second, following Mr. Lucas' suggestion, any customer who installs new equipment could say, 'The Company did not immediately add any costs to serve me, so I should not have to pay for my use of the system.' Of course, that would be unfair and unworkable on its face. When the Company adds a new 1 MW customer, it may not incur additional costs either. That does not mean that we do not charge the customer a fair portion of the overall distribution costs, as reflected in the rates.

Similarly, the Commission must reject Mr. Lucas' argument on behalf of the Solar Projects, that it should not pay for distribution costs if it does not immediately cause additional costs to be incurred.

Q. Mr. Lucas also notes that the Company's cost of service study does not include the gross generator capacity or bi-directional demand data. Please explain why those items are not included.

A. The Company's current meters do not measure bi-directional demand. As a result, we did not have data to include in the ACOS.

For the gross generator capacity, this data will be captured in future cost studies, assuming the Company's proposal is approved by the Commission. As set forth in my Rebuttal Testimony, the Company has captured the estimated additional billing kW in the GLP-1 and GLP-3 rate analysis (again, assuming the Company's proposal is approved). We do not have historic data to make a similar adjustment to the billing determinants.

I would like to note that reflecting historical data for bi-directional peaks in the ACOS allocators would either have no effect, or would increase, the portion of costs borne by GLP-1 customers.

Q. If the Company's proposal is reasonable, has Citizens' been treating its customers in an unreasonable manner since net metering started?

A. The Company must treat its customers as required by the terms of its Tariff. However, not charging generators that use the system by exporting power is not reasonable or fair, hence the proposed change.

Q. Citizens' cost of service study does not reflect the nameplate capacity. Please comment.

A. Neither historical export data nor nameplate capacity were used in developing the ACOS allocators. Demand allocators were the average of historical class Non-Coincident Peak ("NCP") ratios. Mr. Johnson informs me that he believes that including demand information from this customer would not change the class NCP significantly in any year, and in any event, the effect on the average would be negligible.

Q. Will Citizens' see incremental revenue from customer-generators?

A. Citizens' rates are designed to produce a target revenue. The target revenue for the class should be paid by all customers who use the system.

Q. Mr. Lucas appears to argue that it is acceptable if the Solar Projects are not charged, because Citizens' would be kept whole. Please comment.

A. Mr. Lucas' argument misses the point. Citizens' rates are designed to recover the target revenue for each class, from customers in the class who use the system. The costs should

be paid by all customers who use the system. The proposal that the Solar Projects should not pay for distribution system costs flies in the face of this overarching principle.

Q. Does this conclude your Rejoinder Testimony?

A. Yes.

Citizens' Statement No. 4

BEFORE

THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	**:**	
	:	
v.	**:**	**Docket No. R-2025-_____**
	:	
Citizens' Electric Company of Lewisburg, PA	**:**	

DIRECT TESTIMONY
AND EXHIBITS

OF

NATHAN JOHNSON

ON BEHALF OF

CITIZENS' ELECTRIC COMPANY OF LEWISBURG, PA

APRIL 30, 2025

BEFORE
THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	**:**	
	:	
v.	**:**	**Docket No. R-2025-_____**
	:	
Citizens' Electric Company of Lewisburg, PA	**:**	

DIRECT TESTIMONY OF NATHAN JOHNSON
ON BEHALF OF CITIZENS' ELECTRIC COMPANY OF LEWISBURG, PA

Q. Please state your name and business address.

A. My name is Nathan (Nate) Johnson. My business address is 1775 Industrial Blvd., Lewisburg, Pennsylvania.

Q. By whom are you employed and what position do you hold with Citizens' Electric Company of Lewisburg, PA?

A. I am employed by C&T Enterprises, Inc., ("C&T"), and assigned to Citizens' Electric Company of Lewisburg, PA ("Citizens'" or "Company"), as the President and Chief Executive Officer.

Q. What are your duties in that capacity?

A. My duties are to lead and provide general management to Citizens'. I am also responsible for power supply and regulatory issues.

Q. Please describe your educational and professional background.

A. I have a bachelor's degree in electrical engineering from Bucknell University. I joined Citizens' as the Senior Director of Engineering and Operations in 2018. In 2023, I became the President and Chief Executive Officer. Prior to joining Citizens', I held various

technical and supervisory positions in distribution operations with PPL Electric Utilities Corporation. I am also a registered professional engineer in Pennsylvania.

Q. Please describe the purpose of your testimony.

A. My testimony supports the operations, maintenance and capital plan projections that were used by HSG Group, Inc. ("HSG Group") for compilation and preparation of the filing. In discussing this topic, I also address our capital improvement activities, vegetation management, and the proposed changes to Citizens' tariff.

I also provide a general overview of Citizens', its service territory, and its customer base. In addition, I address portions of the historical data, future test year expenses, and capital improvements information provided to Company witness Mr. Gorman for compilation and preparation of the filing. Finally, I will discuss the unique circumstances faced by Citizens' as a small electric utility, and the basis for a performance adjustment to the Company's rate of return.

Q. Please provide a brief overview of Citizens' and its service territory.

A. Citizens' is a small investor-owned Electric Distribution Company ("EDC") under the jurisdiction of the Pennsylvania Public Utility Commission ("PUC" or "Commission") operating in Lewisburg Borough, Buffalo, East Buffalo and Kelly Townships in Union County, Pennsylvania. Citizens' service territory is surrounded by PPL Electric Utilities Corporation ("PPL"). As of December 31, 2024, Citizens' served 5,964 residential customers, 1,164 commercial and industrial customers, and 39 lighting customers – a total of 7,176.

Citizens' was acquired on February 8, 1999, by C&T through the purchase of 99.9% of Citizens' stock with the remaining shares being held by several minority shareholders.

C&T subsequently acquired the remaining outstanding shares, making C&T the sole shareholder of Citizens'. C&T is a holding company and management services firm that is jointly owned by Tri-County Rural Electric Cooperative based in Mansfield, Pennsylvania, and Claverack Rural Electric Cooperative based in Wysox, Pennsylvania. C&T is also the parent corporation of Wellsboro Electric Company ("Wellsboro") and Valley Energy, Inc. ("Valley").

Q. What changes were made to the Company's tariff and operations as a result of the Electricity Generation Customer Choice and Competition Act ("Competition Act")?

A. Citizens' unbundled its generation supply service from its electric distribution service. Electric distribution service remains a service that is regulated by the Commission pursuant to traditional ratemaking processes under Chapter 13 of the Public Utility Code. This filing proposes changes to our unbundled distribution rates in accordance with the Chapter 13 requirements and process.

Citizens' retains the obligation to provide generation supply service to all customers as the Default Service Provider ("DSP") in its service territory in conformance with requirements set forth in the Competition Act. The Commission approves the rules and tariff mechanism to pass through our costs for DSP generation supply service in separate proceedings that address only generation issues. The generation rate is known as our Generation Supply Service Rate ("GSSR" includes GSSR-1 and GSSR-2). We are not proposing to make any changes to the GSSR in this proceeding; however, one change will clarify that we are using a consistent way to measure a customer's billing demand for distribution and generation rate determinations.

Q. Do the proposed distribution rates include any expenses related to generation supply?

A. No. Mr. Gorman's analysis focused solely on our regulated distribution service rates. As a result, both the revenues and expenses related to generation supply services in the historic, future, and fully-projected future test years (HTY, FTY and FPFTY) are removed from our overall revenue and expenses.

In addition, the legal and consulting fees that Citizens' incurs for the generation function are collected through the GSSR and were not included in the distribution rates in this filing. Finally, our cash working capital assumption for the new distribution rates is based only on the portion of the expenses and bills related to distribution service and does not include generation expenses.

Q. When was Citizens' last base rate proceeding?

A. Citizens' last base rate proceeding was in 2022, with the new rates taking effect on January 31, 2023. In that proceeding, we reached a settlement with the parties that resulted in an increase of $930,000 in annual distribution revenues.

Q. What revenue requirement increase is Citizens' requesting in this proceeding?

A. Citizens' is requesting an increase of $1.79 million. On a total bill basis (including generation costs), for the average residential customer using 1,250 kWh per month, this will be a 10.8% increase. A typical small commercial customer on Rate GLP-1 will experience a 5 to 9% increase on a total bill basis. For a larger commercial customer on Rate GLP-3, the increase is 4 to 7%.

Q. Can you explain generally the changes that have occurred since the last rate case?

A. First, although some of the inflation since the COVID period has lessened, we continue to see increases in the costs of materials and equipment, and of labor over that time. To remain competitive in attracting and retaining our employees, we conducted a Wage &

Salary Study in 2024, the results of which are being phased-in over three years (2025 through 2027). The combined impacts of the material cost increases and labor expense increases have increased our Operations and Maintenance ("O&M") expenses by approximately $1.3 million over the expenses reflected in our prior case. In addition, we continue to invest in improvements to our facilities, adding approximately $4.5 million to our net rate base, which to date has not been reflected in our rates. These increases to expenses and rate base have been offset by some increases to our revenues from customers; however, not enough to continue earning a fair return. Mr. Gorman's Exhibit__(HSG-1), Schedule C5-1 calculates how the major elements of our rates have changed since the 2022 settlement.

Without rate relief, we are projected to earn only 1.46% on our rate base in 2026. This clearly is inadequate for any business and will not support our ongoing investments in the system that are needed to continue providing safe and reliable service. Mr. Gorman's Exhibit__(HSG-1), Schedule C1 calculates the rate of return for Citizens' with and without the rate increase requested in this proceeding.

Q. Please discuss the Wage & Salary Study undertaken by Citizens' and C&T 2024.

A. In 2024, Citizens', along with its affiliates in the C&T Enterprises, Inc. family of companies, conducted wage and salary reviews for all non-bargaining positions employed through C&T. This included all positions at Citizens' Electric. A consultant was engaged to facilitate a review of the 105 affected positions by a team comprised of executive management from each affiliated company as well as human resources and legal counsel from C&T Shared Services. The team assessed each position using a quantitative matrix of expertise, leadership, accountability, problem solving, and communication factors to

determine the internal equity of positions and place them in appropriate pay grades. The consultant then brought in external market data from the National Rural Electric Cooperative Association (NRECA), Economic Research Institute (ERI), and American Gas Association (AGA) to align internal salary grades with current labor markets. A final review of grades and associated market salary ranges identified, evaluated, and corrected any outlier positions.

Upon completion of the study, the management team assessed the total magnitude of disparity between current and market wages for all positions to identify a reasonable implementation strategy. The team concluded that an overall 3-year implementation goal was appropriate, with each company given the discretion to manage market adjustments for each employee based on the total disparity to market, performance history, and experience on an individual basis. Citizens' applied the first round of market adjustments effective January 1, 2025. Ms. Stauder's testimony provides an exhibit showing the annual impact on operating expense of the planned implementation.

SMALL UTILITY ISSUES AND COMPANY PERFORMANCE

Q. Do you classify Citizens' as a small utility?

A. Yes. As I mentioned previously, Citizens' serves over 7,200 customers. I further note that in their Direct Testimony, Company witnesses Dylan D'Ascendis and Ryan Kucan of ScottMadden, Inc. conduct a market capitalization analysis showing Citizens' to be a small public utility relative to their comparison group.

Q. As a small, privately-held utility, does Citizens' face any unique financial challenges?

A. Yes. As explained in Mr. D'Ascendis' and Mr. Kucan's testimony, small utilities face increased financial and business risks. A significant risk we face is the reduction of electric load due to business closures or other factors outside of our control that adversely impact our kWh sales (such as weather, net metering, customer on-site generation, etc.). Citizens' capital investment and operating expenses that are necessary to maintain service and reliability remain the same or continue to increase whether we lose customers or distribute less kWh; however, our operating income is decreased. Small utilities also experience greater revenue swings and variation based on weather patterns. Finally, at times, the costs of complying with regulatory requirements can have greater impact on Citizens' than it would on larger EDCs.

Q. Can you discuss the risk of customer loss that Citizens' faces as a small utility?

A. Yes. Approximately one-third of Citizens' load is large commercial and industrial, with 10 of our largest customers representing approximately 23% of our total kWh sales. In the current economic environment, we view a portion of that load as having a high potential risk of closure or relocation. As an unfortunate and actual example, when one customer, Pennsylvania House Furniture ("Pennsylvania House"), ceased operations in Lewisburg at the end of 2004, Citizens' suffered the substantial loss of approximately 5.4% of annual revenues. We had a similar loss in late 2021, when RR Donnelley stopped production in Lewisburg. This reduced our load by 7,104,000 kWh. A portion of the RR Donnelley loss was offset in the last case by adding a new hotel; however, overall, we saw a decrease. Although we are not projecting a loss similar to the RR Donnelley closure in this

proceeding, such events are unpredictable by Citizens' and outside of our control. We face the risk of losing a larger account at any time.

Q. Is Citizens' facing other variables that could reduce anticipated distribution revenues?

A. Yes. We face load variability risks due to solar net metering and energy efficiency efforts. In fact, from 2022 to the current case, we are actually projecting to lose approximately 5,000,000 kWh in sales despite having more customer accounts. *See* Exhibit__(HSG-1), Schedule C5-1.

Q. Can you explain how regulatory requirements can have a magnified impact on smaller utilities?

A. First, let me express our appreciation to the Commission and the General Assembly for recognizing in many instances where smaller utilities should have flexibility in meeting certain regulations and policies. The General Assembly exempted Citizens' and Wellsboro from the mandatory Energy Efficiency and Conservation Plans and from Smart Meter requirements. Similarly, the Commission has allowed us flexibility in designing our DSP plans. In addition, the Commission recently adopted revised regulations for rate case filing requirements that will enable us to request increases of up to $5 million without compiling all of the lengthy requirements set forth in Section 53.53 of the regulations. Because the new regulations have not yet been published in the *Pennsylvania Bulletin*, we used our best efforts in this filing to respond to the old Section 53.53 requirements where we could.

For some items, however, we have the same requirements as the larger EDCs. One requirement is Net Metering. Because of our small size, we have fewer customers to offset

any lost distribution revenues from net metering. The impact of virtual net metering or an oversized net metering project is greater on a smaller EDC than on larger EDCs.

Q. How do you recommend the Commission should address the additional risks faced by small utilities?

A. In my opinion, it is reasonable for the Commission to address this risk through an appropriate overall return on our investment through distribution rates. For the rate of return, the Commission should adopt the recommendation of Mr. D'Ascendis and Mr. Kucan.

Q. Regarding the Company's rate of return, did Mr. D'Ascendis and Mr. Kucan propose any adjustments?

A. Yes, they proposed both a small company adjustment and a performance adjustment.

Q. What are the bases for the small company and performance adjustments proposed by Mr. D'Ascendis and Mr. Kucan?

A. I have already discussed the Company's size, which forms the basis for the proposed small company adjustment. For the performance adjustment, Mr. D'Ascendis' and Mr. Kucan's testimony cites to Section 523 of the Public Utility Code, which provides the Commission's guidelines for performance adjustments. I am advised by counsel that the Public Utility Code identifies several criteria to be considered in assessing the performance of a fixed utility for purposes of a performance factor adjustment, including consideration of any relevant and material evidence of efficiency, effectiveness, and adequacy of service. The Commission should consider Citizens' operations as supportive of the proposed performance adjustment, including the following:

- **Low customer complaints.** For the period 2022-2024, Citizens' received no formal complaints and 22 informal complaints, resolved in an average resolution period of 24 days. Of the 22 informal complaints, 18 were requests for Commission issued payment arrangements. The remaining 4 related to billing disputes, all of which were dismissed by BCS staff. A spreadsheet tracking the formal and informal PUC complaints and resolution timeframes for the period 2022-2024 is attached as Exhibit__(NJ-1).
- **Favorable customer feedback.** We consistently receive very favorable evaluations and comments from our customers, with over 90% of customers providing a 'Very Satisfied' rating on the past three years' Annual Customer Contact survey.
- **High responsiveness: customer support calls.** Records from the Commission's Quality of Service System attached as Exhibit__(NJ-2) show Citizens' has answered, on average, more than 97% of customer phone calls within 30 seconds. Citizens' has been and remains very responsive to customer inquiries.
- **High responsiveness: energizing new service locations.** The spreadsheet attached as Exhibit__(NJ-3) demonstrates that new service locations are energized, on average, within four days of receipt of an approved cut-in card from an electrical inspector.
- **Excellent reliability metrics.** The PUC's *Pennsylvania Electric Reliability Report 2023* (the latest report available), shows that Citizens' has maintained the lowest 3-year average CAIDI, SAIFI and SAIDI of all Pennsylvania EDCs. Exhibit__(NJ-

4) contains *Appendix A – Electric Reliability Metrics* from the PUC's 2023 report, showing Citizens' performance for the 2023 calendar year and 3-year average.

- **Zero reportable injuries.** Citizens' had zero reportable injuries in 2024, as demonstrated by the OSHA Form 300A attached as Exhibit__(NJ-5).
- **Technology adoption: SmartHub use.** A total of 3,210 customers, representing 3,863 accounts (over half of Citizens' total accounts) are now using SmartHub to receive and/or pay their bills electronically, analyze detailed usage reports, report and check on outages, and conduct other business with the Company via a mobile application or the website. SmartHub provides significant customer convenience and is available 24 hours a day.
- **Technology adoption: tablets for line crews.** With tablets provided to line crews, the crews are able to complete inspections, report some types of work completed, view up-to-date system maps, view live analysis of outages, access online material safety information, consult company safety and procedures manuals, complete time sheets, and view live system, customer and right-of-way records. This is a significant asset to the crews and increases their efficiency, safety, and knowledge.
- **Increased pole attachment billing.** Citizens' continues to update its pole attachment fees annually since implementing the FCC cost formulae in 2022. The Company is currently assessing the value of a system-wide one-time or programmatic audit of attachments to capture undocumented attachments and other violations, further shifting costs from ratepayers to the organizations actually incurring attachments-related costs.

- **"Tree Line USA" designation.** The Company has been recognized by the National Arbor Day Foundation as a "Tree Line USA" utility for the 23rd consecutive year. This recognition acknowledges Citizens' commitment to proper tree pruning techniques which result in a more efficient vegetation management program and healthier trees. Exhibit__(NJ-6) contains a recent press release documenting this designation.
- **Significant capital investment.** As discussed below, Citizens' continues to invest approximately $1.9 million annually in system replacements and improvements. Exhibit__(NJ-7) shows three years of capital results. These investments were funded from base rates, without assessing a Distribution System Improvement Charge upon customers.

CITIZENS' CAPITAL PROJECTS

Q. Could you please describe some of the distribution system projects Citizens' has completed since the Company's last rate case?

A. In addition to ongoing maintenance and operations, the Company has invested in capital improvements. These plant investments were in the form of replacing aged poles, increasing conductor size to provide greater operating flexibility and reliability, replacing underground cable, reconductoring to increase capacity and reliability, replacing first-generation smart meters, and relocating lines for reliability improvement. Additionally, Citizens' has completed numerous small line extensions and upgrades.

Q. Please provide some examples of projects that the Company is undertaking in 2025 and 2026.

A. Significant capital projects for our Future Test Year and Fully-Projected Future Test Year include:

- **Neutral Reconductoring along Route 15.** The Company has budgeted $15,000 each in 2025 and 2026 to upgrade the neutral conductor on the main supply circuit to the southeastern extent of the service area. This will allow full utilization of the capacity of the existing three-phase primary conductors in the area.
- **Recloser Replacements.** The Company budgeted $67,000 to replace single-phase reclosers and older-style three-phase reclosers with new electronic vacuum reclosers ("VCR") in 2025 and 2026. The new VCRs will be installed in lieu of preventative maintenance on the Company's existing fleet of single-phase and three-phase hydraulic oil circuit reclosers ("OCR"), which are nearing end-of-life. This will provide both a cost and operational benefit by reducing maintenance needs and increasing reliability.
- **Underground Cable Reconductoring in Weiser Heights Development.** This project upgrades 1970s vintage cable and will ensure continued reliability for customers. The Company has budgeted $65,000 in 2025 for this project and $100,000 in 2026. Recognizing the limited, remaining life expectancy of the 1970-vintage direct buried, underground, high voltage cables, the Company plans to continue a systematic cable replacement program.
- **Three-Phase Relocation along Glover Hill Rd.** The Company has budgeted $150,000 in 2025 to relocate an inaccessible three-phase circuit along Glover Hill Rd. This project will

also address replacing several poles that have failed recent inspections and moving them along the road.

Q. Do you anticipate that the rate of capital improvements will continue?

A. Yes, Citizens' has a 5-year work plan that includes additional improvements. A copy of our 5-year work plan is included in the filing as Citizens Confidential Exhibit 2.

Q. Please discuss Citizens' vegetation management program.

A. Citizens' annually inspects all of its approximately 160 miles of overhead line to assess vegetation management needs. Most of our scheduled vegetation management is accomplished by an outside contractor. We solicit bids for vegetation management and specify to the contractor the total miles to be accomplished. Prior to the contract year, we establish a specific schedule for projects based on a number of factors, including identification of priority trees.

For 2025, we are increasing our vegetation management expenses by approximately 6% over 2024 to address faster than expected regrowth and increased efforts to identify and remove emergent hazard trees. This will be an ongoing increase to our historic performance to reflect both operational realities (i.e., faster regrowth) and the Commission's emphasis on vegetation management efforts to enhance reliability. Additionally, 2025 bids for the tree trimming contract indicate that significant price increases can be expected in future years; Exhibit__(NJ-8) demonstrates this trend. For 2026, we have increased our budget forecast for tree trimming work by 81% in anticipation of these cost increases.

Q. Is Citizens' using technology to assist with vegetation management?

A. Yes. In 2023, we conducted a pilot project with an outside vendor to conduct drone inspections of our system. Beginning in 2025 and for the subsequent years, we are contracting with a vendor to conduct drone inspections of our facilities. This program will assist us in identifying conditions that are not readily apparent from a ground-level inspection. Also, the company is evaluating various digital tools to increase the efficiency and accuracy of conducting and documenting vegetation management inspections.

Q. Does Citizens' O&M and Capital spending vary from quarter to quarter during the year?

A. Yes. Due our small size, Citizens' can only work on a limited number of projects concurrently. Since work on budgeted projects is typically continuous from start to finish, spending tends to reflect any individual major projects under way at the time. For example, when a major line reconductoring project is under construction, it may require 75% or more of the workforce on a typical day. The result is that spending during that time will be predominantly Capital. Upon completion of the project, the workforce may move on to I&M inspections, at which point spending will shift towards O&M. This is also true of contracted work, such as tree trimming or underground cable replacement. In addition to an inherently low volume of concurrent work, weather also drives certain patterns in spending. Major projects tend to be completed in the shoulder months when favorable weather and low demand allow for uninterrupted work and greater flexibility in load transfers. During winter and storm season, smaller projects or I&M inspections provide work that requires little switching and can easily be put on hold during foul weather or outage restorations.

Q. Are Citizens' operations, maintenance and replacement practices resulting in safe, adequate and reliable service to customers?

A. Yes. Citizens' traditionally has among the best SAIDI (System Average Interruption Duration Index – measures average outage duration time for every customer served), SAIFI (System Average Interruption Frequency Index – measures average frequency of interruptions for every customer), and CAIDI (Customer Average Interruption Duration Index – measures average restoration time for every customer who lost power) among Pennsylvania electric utilities.

PROPOSED TARIFF CHANGES

Q. What changes does Citizens' propose to make to its tariff as part of this filing?

A. In preparation for this filing, the Citizens' management and staff reviewed each provision in the tariff to determine where updates or changes may be appropriate.

One important issue that we are clarifying is how customers with smaller on-site generation resources will be placed on distribution rate schedules and billed for service. We also have some clarifications to tariff rules.

Q. Please provide an overview of the changes to address customer-generators.

A. Since the adoption of the Alternative Energy Portfolio Standards ("AEPS") Act in 2014, Pennsylvania has been focused on issues surrounding "customer generators", which are defined as:

> A nonutility owner or operator of a net metered distributed generation system with a nameplate capacity of not greater than 50 kilowatts if installed at a residential service or not larger than 3,000 kilowatts at other customer service locations, except for customers whose systems are above 3 megawatts and up to 5 megawatts who make their systems available to operate in parallel with the electric utility during grid emergencies as defined by the regional transmission organization or where a microgrid is in place for the primary or secondary purpose of maintaining critical infrastructure . . . .

Customer generators are entitled to receive "Net Metering" from the electric distribution company.

Until recently, we assumed that customer generators must be classified for distribution and generation purposes based on amount of peak electricity that the electric distribution company supplied to the customer generator's account. However, a recent decision by the Commission in *Petition of UGI Utilities, Inc-Electric Division for Approval of a Default Service Plan for the Period of June 1, 2025 though May 31, 2029*¸ Docket No. P-2004-3049343, et al., indicated that customer generators can be classified for generation purposes according to their peak electricity imported from the EDC or exported to the EDC.

We are proposing to clarify in our tariff that we will use customer generator's net power flow from or onto the Company's distribution system to establish the distribution charges for the account and eligibility for the Generation Supply Service Rate ("GSSR") 1 or GSSR-2. For customers with Billing Demands over 400 kW, the annual cash out will be a weighted average locational marginal price ("LMP").

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Q. Why is it appropriate to use the net power flow from or onto the Company's distribution system?

A. Using these measures provides an accurate reflection of the Customer's use of the distribution system. From a distribution perspective, we have to plan the same for a customer that is exporting 400 kW to Citizens' as we do for a customer that is receiving 400 kW from Citizens'. In fact, our planning for the export of power to us is more complicated because of potential variability, voltage sags/surges and other issues. It is

equitable to charge a customer exporting 400 kW to us similar to how we charge a customer that uses 400 kW.

In the recent *UGI Electric* Order, the Commission determined that is appropriate to treat these customers similarly for generation supply services. For Citizens', this will ensure that we apply a uniform definition of "billing demand", which is used in our distribution rate schedules and the GSSR-1 and GSSR-2 Riders.

Q. Please discuss the tariff changes to implement this proposal.

First, we are proposing to add an explanation in Rule 26—Determination of Billing Demand stating:

> (a) **Billing Demand:** Billing Demand shall reflect the Customer's use of the distribution system, which will be the greater of Gross Generator Rating (kW(AC)) as stated in the generator interconnection application or the maximum demand of the customer during any 15-minute period during the current month.

Second, for GLP-1 and GLP-3, we would modify the 'Billing Demand" sections of each as follows:

> "Billing Demand" is <u>defined in Rule 26(a),</u> but not less than 50% of the highest Billing Demand during the preceding eleven months."

Third, in the "Generation Supply Rates" portion of GLP-1 and GLP-3, we propose to capitalize the two occurrences of "Billing Demand". We would make the same capitalization changes in the GSSR-1 and GSSR-2 Riders, where "monthly billing demand" occurs in the first paragraph of each rider.

Q. Do you have any other changes to the tariff to standardize the definition of Billing Demand?

A. Yes. We are proposing to clarify the "Application of Schedule" sections of GLP-1 and GLP-3 to remove the reference to the customer choosing alternative service voltages.

Finally, for GLP-3, we are specifying that the 50 kW minimum demand is based on the Billing Demand.

Q. Does Citizens' have additional tariff changes?

A. Yes. We have clarifications to Rules 5, 12(b), and 17(b), and a modification to how we will treat seasonal service.

Q. Please provide the clarifications.

In Rule 5, we are changing the phrase "is willing to" to "may".

In Rule 12(b), we are adding language that confirms a Customer's ability to request an in-person meter reading for a charge of $35.00.

In Rule 17(b), we are clarifying the premises owner's responsibility to accurately label meters if there are two or more meters installed at a building.

Q. What changes is Citizens' proposing to seasonal service?

A. Citizens' current seasonal service provisions in Rule 30(B)(2) is confusing for customers and cumbersome for Citizens' to administer. We are proposing to streamline the rule by requiring the premises owner or customer to pay the minimum charge under the tariff for each month the seasonal service is disconnected, as well as the cost of disconnection and reconnection.

Q. Does this conclude your Direct Testimony?

A. Yes.

BEFORE

THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	**:**	
	:	
v.	**:**	**Docket No. R-2025-_____**
	:	
Citizens' Electric Company of Lewisburg, PA	**:**	

EXHIBITS

OF

NATHAN JOHNSON

ON BEHALF OF

CITIZENS' ELECTRIC COMPANY OF LEWISBURG, PA

APRIL 30, 2025

CITIZENS' Electric COMPANY
Over a Century of Service

2022 Formal Complaints

Case #	Type of Complaint
Total Cases:	**0**

2022 Informal Complaints

Case #	Resolved *(days)*	Type of Complaint
	46	PAR/TERMINATION
Total Cases:		**1**
Avg Days to Resolution:		**46**

*** PAR - PAYMENT ARRANGEMENT ***

CITIZENS' Electric COMPANY
Over a Century of Service

2023 Formal Complaints

Case #	Type of Complaint
Total Cases:	**0**

2023 Informal Complaints

Case #	Resolved *(days)*	Type of Complaint
	9	PAR/TERMINATION
	32	PAR/TERMINATION
	9	PAR/TERMINATION
	44	PAR/TERMINATION
	7	PAR/TERMINATION
	120	FOREIGN LOAD/DISMISSED
	36	PAR/DISMISSED
	17	PAR/DISMISSED
	7	PAR/DISMISSED
	9	PAR/DISMISSED
	1	PAR/DISMISSED
	9	PAR/TERMINATION
	9	PAR/TERMINATION
Total Cases:		**13**
Avg Days to Resolution:		**24**

*** PAR - PAYMENT ARRANGEMENT ***

CITIZENS' Electric COMPANY
Over a Century of Service

2024 Formal Complaints

Case #	Type of Complaint
Total Cases:	**0**

2024 Informal Complaints

Case #	Resolved *(days)*	Type of Complaint
	17	BILLING DISPUTE/DISMISSED
	7	PAR/TERMINATION
	1	TERMINATION DISPUTE/DISMISSED
	53	BILLING DISPUTE/DISMISSED
	7	PAR/TERMINATION
	1	PAR/TERMINATION
	34	BILLING DISPUTE/DISMISSED
	58	PAR/INCOME CHANGE
Total Cases:	**8**	
Avg Days to Resolution:	**22**	

*** PAR - PAYMENT ARRANGEMENT ***

Year	Month	% Calls <30s
2022	January	97.0%
2022	February	98.3%
2022	March	97.7%
2022	April	98.5%
2022	May	98.3%
2022	June	99.3%
2022	July	99.3%
2022	August	99.7%
2022	September	100.0%
2022	October	98.6%
2022	November	99.5%
2022	December	98.1%
	12-mo Average:	98.69%

Year	Month	% Calls <30s
2023	January	99.4%
2023	February	100.0%
2023	March	100.0%
2023	April	100.0%
2023	May	98.8%
2023	June	98.6%
2023	July	99.2%
2023	August	99.1%
2023	September	99.1%
2023	October	97.9%
2023	November	98.7%
2023	December	100.0%
	12-mo Average:	99.23%

Year	Month	% Calls <30s
2024	January	99.4%
2024	February	99.4%
2024	March	99.5%
2024	April	99.3%
2024	May	99.5%
2024	June	99.4%
2024	July	98.6%
2024	August	97.9%
2024	September	100.0%
2024	October	82.6%
2024	November	87.6%
2024	December	82.9%
	12-mo Average:	95.51%

SO WIN	Open Dt	Close Date	SO Type	Work Order	Cut-In Card Received	Days to Connect
66692	3/20/2020	5/5/2022	NEW - New Service		3/18/2020	*
70082	5/7/2021	3/29/2022	NEW - New Service	20220308	3/25/2022	4
71695	8/18/2021	3/3/2022	NEW - New Service	20210901	3/3/2022	0
72061	9/21/2021	2/11/2022	NEW - New Service		2/2/2021	*
72152	10/6/2021	1/21/2022	NEW - New Service	20211102	1/13/2022	8
72309	11/9/2021	8/26/2022	NEW - New Service	20220604	6/10/2022	*
72311	11/9/2021	8/26/2022	NEW - New Service	20220604	6/10/2022	*
72312	11/9/2021	8/26/2022	NEW - New Service	20220604	6/10/2022	*
72313	11/9/2021	8/26/2022	NEW - New Service	20220604	6/10/2022	*
72434	11/26/2021	3/22/2022	NEW - New Service	20220201	3/18/2021	*
72501	12/9/2021	4/26/2022	NEW - New Service	20211205	4/20/2022	6
72516	12/13/2021	1/31/2022	NEW - New Service		1/25/2022	6
72700	1/20/2022	2/8/2022	NEW - New Service	20220103	2/3/2022	5
72777	2/15/2022	5/11/2022	NEW - New Service	20220202	4/28/2022	*
72860	3/7/2022	5/12/2023	NEW - New Service	20220407	5/9/2022	*
72876	3/9/2022	5/6/2022	NEW - New Service	20220309	4/28/2022	8
73033	4/7/2022	4/13/2022	NEW - New Service		4/7/2022	6
73098	4/22/2022	4/26/2022	NEW - New Service	20220403	4/22/2022	4
73099	4/22/2022	4/29/2022	NEW - New Service	20220405	5/4/2022	*0*
73169	4/29/2022	4/29/2022	NEW - New Service		4/29/2022	0
73178	5/3/2022	5/5/2022	NEW - New Service		5/3/2022	2
73808	5/26/2022	7/12/2022	NEW - New Service	20220702	10/6/2022	*0*
74083	6/7/2022	6/15/2022	NEW - New Service	20220603	6/10/2022	5
74423	6/14/2022	9/1/2022	NEW - New Service	20220605	8/17/2022	*
74459	6/17/2022	9/26/2022	NEW - New Service	20220607	9/13/2022	*
74488	6/22/2022	6/29/2022	NEW - New Service	20220608	6/24/2022	5
74798	7/12/2022	9/20/2022	NEW - New Service	20220906	9/21/2022	*0*
74836	7/18/2022	9/14/2022	NEW - New Service	20220704	9/9/2022	5
74861	7/22/2022	7/28/2022	NEW - New Service		7/25/2022	3
74862	7/22/2022	7/28/2022	NEW - New Service		7/25/2022	3
74863	7/22/2022	7/28/2022	NEW - New Service		7/25/2022	3
74864	7/22/2022	7/28/2022	NEW - New Service		7/25/2022	3
74920	7/27/2022	8/11/2022	NEW - New Service	20220803	8/10/2022	1
74925	7/28/2022	10/10/2022	NEW - New Service	20220908	10/6/2022	4
75046	8/3/2022	9/13/2023	NEW - New Service	20220805	9/11/2023	2
75057	8/4/2022	11/1/2022	NEW - New Service	20221002	10/19/2022	*
75058	8/4/2022	9/30/2022	NEW - New Service	20220904	9/13/2022	*
75106	8/9/2022	8/9/2022	NEW - New Service		10/21/2022	*0*
75390	9/15/2022	11/11/2022	NEW - New Service	20220909	11/10/2022	1
75658	11/1/2022	2/28/2023	NEW - New Service		2/22/2023	6
75764	11/22/2022	1/25/2023	NEW - New Service		1/19/2023	6
75794	11/28/2022	1/17/2023	NEW - New Service	20221202	1/12/2023	5

SO WIN	Open Dt	Close Date	SO Type	Work Order	Cut-In Card Received		Days to Connect
75831	12/1/2022	1/9/2023	NEW - New Service	20221204	1/5/2023		4
76023	1/6/2023	1/11/2023	NEW - New Service		1/9/2023		2
76032	1/10/2023	1/12/2023	NEW - New Service		2/24/2025		*0*
76068	1/16/2023	10/23/2023	NEW - New Service	20230508	10/17/2023		6
76123	1/27/2023	2/27/2023	NEW - New Service	20230202	2/22/2023		5
76177	2/6/2023	6/6/2023	NEW - New Service	20230309	4/20/2023	*	
76179	2/6/2023	6/6/2023	NEW - New Service	20230309	4/20/2023	*	
76213	2/13/2023	3/24/2023	NEW - New Service	20230207	3/21/2023		3
76218	2/14/2023	2/17/2023	NEW - New Service		2/14/2023		3
76330	3/7/2023	3/23/2023	NEW - New Service	20230303	3/22/2023		1
76338	3/8/2023	3/16/2023	NEW - New Service		3/13/2023		3
76339	3/8/2023	3/16/2023	NEW - New Service		3/13/2023		3
76418	3/23/2023	10/11/2023	NEW - New Service	20230402	9/14/2023	*	
76458	3/31/2023	3/27/2024	NEW - New Service	20230307	3/26/2024		1
76505	4/12/2023	6/19/2023	NEW - New Service	20230405	6/12/2023		7
77129	6/8/2023	8/23/2023	NEW - New Service	20230713	7/25/2023	*	
77195	6/15/2023	7/6/2023	NEW - New Service	20230605	6/28/2023		8
77196	6/15/2023	7/6/2023	NEW - New Service	20230605	6/28/2023		8
77309	6/30/2023	9/20/2023	NEW - New Service	20230803	9/18/2023		2
77387	7/7/2023	9/5/2023	NEW - New Service	20230201	8/7/2023	*	
77473	7/14/2023	9/15/2023	NEW - New Service	20230608	9/13/2023		2
77475	7/14/2023	8/30/2023	NEW - New Service	20230608	8/30/2023		0
77476	7/14/2023	9/15/2023	NEW - New Service	20230608	9/13/2023		2
77633	7/28/2023	9/12/2023	NEW - New Service	20230712	9/11/2023		1
77772	8/11/2023	9/18/2023	NEW - New Service	20230711	9/6/2023		12
77807	8/16/2023	9/14/2023	NEW - New Service	20230801	9/11/2023		3
77845	8/21/2023	11/1/2023	NEW - New Service	20230904	10/11/2023	*	
77883	9/8/2023	9/29/2023	NEW - New Service	20230902	9/6/2023	*	
77884	9/8/2023	10/2/2023	NEW - New Service	20230903	9/6/2023	*	
78237	9/27/2023	1/5/2024	NEW - New Service	20230901	1/2/2024		3
78395	10/27/2023	6/26/2024	NEW - New Service	20231101	5/21/2024	*	
78463	11/6/2023	9/19/2024	NEW - New Service	20230704	9/17/2024		2
78479	11/7/2023	11/13/2023	NEW - New Service	20231102	11/10/2023		3
78575	11/21/2023	2/14/2024	NEW - New Service	20231105	2/9/2024		5
78583	11/22/2023	11/22/2023	NEW - New Service		11/23/2023		*0*
78618	11/30/2023	1/3/2024	NEW - New Service		12/27/2023		7
78619	11/30/2023	1/3/2024	NEW - New Service		12/27/2023		7
78668	12/11/2023	1/2/2024	NEW - New Service	20231207	3/20/2024		*0*
78681	12/13/2023	12/13/2023	NEW - New Service		8/14/2023	*	
78752	12/29/2023	9/9/2024	NEW - New Service	20231004B	4/12/2024	*	
78847	1/15/2024	4/19/2024	NEW - New Service	20240108	3/25/2024	*	
78915	1/31/2024	1/31/2024	NEW - New Service		2/9/2024		*0*

SO WIN	Open Dt	Close Date	SO Type	Work Order	Cut-In Card Received	Days to Connect	
78978	2/13/2024	5/8/2024	NEW - New Service	20240301	5/2/2024	6	
78979	2/13/2024	5/8/2024	NEW - New Service	20240301	5/2/2024	6	
79101	3/12/2024	4/5/2024	NEW - New Service	20240307	3/25/2024	11	
79119	3/15/2024	3/25/2024	NEW - New Service	20240304	3/22/2024	3	
79120	3/15/2024	7/9/2024	NEW - New Service	20240305	5/13/2024	*	
79130	3/20/2024	3/22/2024	NEW - New Service	20240202	3/20/2024	2	
79140	3/21/2024	5/3/2024	NEW - New Service	20240402	4/18/2024	*	
79223	4/4/2024	4/17/2024	NEW - New Service	20231205	4/9/2024	8	
79224	4/4/2024	4/17/2024	NEW - New Service	20231205	4/9/2024	8	
79304	4/19/2024	10/15/2024	NEW - New Service	20240504	10/11/2024	4	
79579	5/17/2024	5/30/2024	NEW - New Service	20230602B	5/23/2024	7	
79856	6/11/2024	6/11/2024	NEW - New Service	20231205B	6/19/2024	*0*	
79908	6/18/2024	11/11/2024	NEW - New Service	20240704	9/10/2024	*	
79923	6/19/2024	9/5/2024	NEW - New Service		8/9/2024	*	
79925	6/19/2024	6/26/2024	NEW - New Service		6/19/2024	7	
79982	6/25/2024	9/13/2024	NEW - New Service	20230602	9/11/2024	2	
79983	6/25/2024	9/13/2024	NEW - New Service		9/11/2024	2	
79986	6/25/2024	9/13/2024	NEW - New Service		9/11/2024	2	
79987	6/25/2024	9/13/2024	NEW - New Service		9/11/2024	2	
79988	6/25/2024	9/13/2024	NEW - New Service		9/11/2024	2	
79989	6/25/2024	9/13/2024	NEW - New Service		9/11/2024	2	
79991	6/26/2024	7/29/2024	NEW - New Service		8/19/2024	*0*	
79992	6/26/2024	7/29/2024	NEW - New Service		7/25/2024	4	
79993	6/26/2024	7/29/2024	NEW - New Service		7/25/2024	4	
79994	6/26/2024	7/29/2024	NEW - New Service		7/25/2024	4	
79995	6/26/2024	7/29/2024	NEW - New Service		7/25/2024	4	
79996	6/26/2024	7/29/2024	NEW - New Service		7/24/2024	5	
79997	6/26/2024	7/29/2024	NEW - New Service		7/24/2024	5	
79998	6/26/2024	7/29/2024	NEW - New Service		7/24/2024	5	
79999	6/26/2024	7/29/2024	NEW - New Service		7/24/2024	5	
80000	6/26/2024	7/29/2024	NEW - New Service		7/24/2024	5	
80001	6/26/2024	7/29/2024	NEW - New Service		7/24/2024	5	
80003	6/26/2024	7/29/2024	NEW - New Service		7/24/2024	5	
80004	6/26/2024	7/29/2024	NEW - New Service		7/24/2024	5	
80005	6/26/2024	7/29/2024	NEW - New Service		7/24/2024	5	
80006	6/26/2024	10/11/2024	NEW - New Service		10/9/2024	2	
80008	6/26/2024	10/11/2024	NEW - New Service		10/9/2024	2	
80009	6/26/2024	10/11/2024	NEW - New Service		10/9/2024	2	
80010	6/26/2024	10/11/2024	NEW - New Service		10/9/2024	2	
80011	6/26/2024	10/11/2024	NEW - New Service		10/9/2024	2	
80012	6/26/2024	10/11/2024	NEW - New Service		10/9/2024	2	
80013	6/26/2024	10/11/2024	NEW - New Service		10/9/2024	2	

SO WIN	Open Dt	Close Date	SO Type	Work Order	Cut-In Card Received		Days to Connect
80014	6/26/2024	10/11/2024	NEW - New Service		10/9/2024		2
80015	6/26/2024	10/25/2024	NEW - New Service		10/22/2024		3
80016	6/26/2024	10/25/2024	NEW - New Service		10/22/2024		3
80017	6/26/2024	10/25/2024	NEW - New Service		10/22/2024		3
80018	6/26/2024	10/25/2024	NEW - New Service		10/22/2024		3
80019	6/26/2024	11/26/2024	NEW - New Service		11/22/2024		4
80020	6/26/2024	11/26/2024	NEW - New Service		11/22/2024		4
80021	6/26/2024	11/26/2024	NEW - New Service		11/22/2024		4
80022	6/26/2024	11/26/2024	NEW - New Service		11/22/2024		4
80030	6/26/2024	10/28/2024	NEW - New Service	20230602	10/25/2024		3
80031	6/26/2024	9/13/2024	NEW - New Service		9/11/2024		2
80353	7/16/2024	8/21/2024	NEW - New Service	20240708	8/19/2024		2
80456	7/23/2024	9/16/2024	NEW - New Service	20240904	9/16/2024		0
80466	7/24/2024	10/25/2024	NEW - New Service	20240802	10/11/2024	*	
80636	7/31/2024	8/7/2024	NEW - New Service		7/31/2024		7
80639	7/31/2024	11/12/2024	NEW - New Service	20240711	11/7/2024		5
80741	8/9/2024	10/11/2024	NEW - New Service	20241003	10/8/2024		3
81182	10/4/2024	12/6/2024	NEW - New Service		12/4/2024		2
81205	10/7/2024	11/21/2024	NEW - New Service		11/19/2024		2
81206	10/7/2024	11/21/2024	NEW - New Service		11/19/2024		2
81207	10/7/2024	11/21/2024	NEW - New Service		11/19/2024		2
81209	10/8/2024	11/21/2024	NEW - New Service		11/19/2024		2
81246	10/16/2024	10/30/2024	NEW - New Service	20240702	11/21/2024		*0*
81281	10/22/2024	12/19/2024	NEW - New Service	20241006	12/16/2024		3
81531	12/10/2024	12/19/2024	NEW - New Service	20241201	12/17/2024		2

Delayed due to or at request of customer.

Average	3.5

Appendix A – Electric Reliability Metrics

12-Month Average Electric Reliability Indices for 2023

Customer Average Interruption Duration Index (CAIDI)- min/yr/cust				% Above (+) or	% Above (+) or
EDC	Dec-23	Benchmark	Standard	Below (-) Benchmark	Below (-) Standard
Citizens'	90	105	141	-14.5%	-36.3%
Duquesne Light	110	108	130	1.9%	-15.4%
Met-Ed (FE)	202	117	140	72.4%	44.0%
PECO	138	112	134	23.2%	3.0%
Penelec (FE)	189	117	141	61.7%	34.2%
Penn Power (FE)	157	101	121	55.0%	29.3%
Pike County	95	174	235	-45.4%	-59.6%
PPL	189	145	174	30.3%	8.6%
UGI	112	169	228	-33.7%	-50.9%
Wellsboro	114	124	167	-8.1%	-31.7%
West Penn (FE)	266	170	204	56.6%	30.5%
System Average Interruption Frequency Index (SAIFI)- outages/yr/cust				% Above (+) or	% Above (+) or
EDC	Dec-23	Benchmark	Standard	Below (-) Benchmark	Below (-) Standard
Citizens'	0.32	0.20	0.27	60.0%	18.5%
Duquesne Light	0.57	1.17	1.40	-51.3%	-59.3%
Met-Ed (FE)	1.27	1.15	1.38	10.4%	-8.0%
PECO	0.74	1.23	1.48	-39.8%	-50.0%
Penelec (FE)	1.60	1.26	1.52	27.0%	5.3%
Penn Power (FE)	0.78	1.12	1.34	-30.4%	-41.8%
Pike County	0.86	0.61	0.82	41.0%	4.9%
PPL	0.78	0.98	1.18	-20.4%	-33.9%
UGI	0.54	0.83	1.12	-34.9%	-51.8%
Wellsboro	1.37	1.23	1.66	11.4%	-17.5%
West Penn (FE)	1.07	1.05	1.26	1.9%	-15.1%
System Average Interruption Duration Index (SAIDI)- min/yr/cust				% Above (+) or	% Above (+) or
EDC	Dec-23	Benchmark	Standard	Below (-) Benchmark	Below (-) Standard
Citizens'	29	21	38	38.1%	-23.7%
Duquesne Light	63	126	182	-49.9%	-65.3%
Met-Ed (FE)	257	135	194	90.3%	32.4%
PECO	103	138	198	-25.4%	-48.0%
Penelec (FE)	303	148	213	104.9%	42.4%
Penn Power (FE)	121	113	162	7.4%	-25.1%
Pike County	82	106	194	-22.6%	-57.7%
PPL	147	142	205	3.5%	-28.3%
UGI	61	140	256	-56.4%	-76.2%
Wellsboro	155	153	278	1.3%	-44.2%
West Penn (FE)	285	179	257	59.3%	11.0%

*Note: **GREEN** = better than benchmark; **RED** = worse than standard; **BLACK** = between benchmark and standard.*

Performance Benchmark. An EDC's performance benchmark is calculated by averaging the EDC's annual, system-wide reliability performance indices over the five-year period directly prior to the implementation of electric restructuring (1994 to 1998). The benchmark is the level of performance that the EDC should strive to achieve and maintain.

2023 Pennsylvania Electric Reliability Report

Three-Year Average Electric Reliability Indices for 2021-2023

Customer Average Interruption Duration Index (CAIDI)-min/yr/cust				*3-Year*	*3-Year*	*% Above (+) or*
EDC	*2021*	*2022*	*2023*	*Average*	*Standard*	*Below (-) Standard*
Citizens'	*94*	*101*	*90*	*95*	*115*	*-17.4%*
Duquesne Light	*187*	*146*	*110*	*148*	*119*	*24.1%*
Met-Ed (FE)	*173*	*160*	*202*	*178*	*129*	*38.2%*
PECO	*187*	*99*	*138*	*141*	*123*	*14.9%*
Penelec (FE)	*151*	*199*	*189*	*180*	*129*	*39.3%*
Penn Power (FE)	*129*	*134*	*157*	*140*	*111*	*26.0%*
Pike County	*153*	*159*	*95*	*136*	*192*	*-29.3%*
PPL	*187*	*164*	*189*	*180*	*160*	*12.5%*
UGI	*134*	*156*	*112*	*134*	*186*	*-28.0%*
Wellsboro	*144*	*130*	*114*	*129*	*136*	*-4.9%*
West Penn (FE)	*192*	*276*	*266*	*245*	*187*	*30.9%*
System Average Interruption Frequency Index (SAIFI)-outages/yr/cust				*3-Year*	*3-Year*	*% Above (+) or*
EDC	*2021*	*2022*	*2023*	*Average*	*Standard*	*Below (-) Standard*
Citizens'	*0.27*	*0.27*	*0.32*	*0.29*	*0.22*	*30.3%*
Duquesne Light	*0.93*	*0.92*	*0.57*	*0.81*	*1.29*	*-37.5%*
Met-Ed (FE)	*1.35*	*1.32*	*1.27*	*1.31*	*1.27*	*3.4%*
PECO	*0.88*	*0.71*	*0.74*	*0.78*	*1.35*	*-42.5%*
Penelec (FE)	*1.84*	*1.83*	*1.60*	*1.76*	*1.39*	*26.4%*
Penn Power (FE)	*1.00*	*0.99*	*0.78*	*0.92*	*1.23*	*-24.9%*
Pike County	*1.40*	*0.50*	*0.86*	*0.92*	*0.67*	*37.3%*
PPL	*0.91*	*0.87*	*0.78*	*0.85*	*1.08*	*-21.0%*
UGI	*0.95*	*0.87*	*0.54*	*0.79*	*0.91*	*-13.6%*
Wellsboro	*0.93*	*1.09*	*1.37*	*1.13*	*1.35*	*-16.3%*
West Penn (FE)	*1.26*	*1.32*	*1.07*	*1.22*	*1.16*	*4.9%*
System Average Interruption Duration Index (SAIDI)-min/yr/cust				*3-Year*	*3-Year*	*% Above (+) or*
EDC	*2021*	*2022*	*2023*	*Average*	*Standard*	*Below (-) Standard*
Citizens'	*26*	*28*	*29*	*27*	*25*	*9.5%*
Duquesne Light	*173*	*134*	*63*	*123*	*153*	*-19.4%*
Met-Ed (FE)	*233*	*211*	*257*	*234*	*163*	*43.3%*
PECO	*164*	*71*	*103*	*113*	*167*	*-32.5%*
Penelec (FE)	*277*	*364*	*303*	*315*	*179*	*75.9%*
Penn Power (FE)	*129*	*133*	*121*	*128*	*136*	*-6.1%*
Pike County	*216*	*79*	*82*	*126*	*129*	*-2.6%*
PPL	*170*	*142*	*147*	*153*	*172*	*-11.0%*
UGI	*127*	*135*	*61*	*108*	*170*	*-36.7%*
Wellsboro	*133*	*142*	*155*	*143*	*185*	*-22.5%*
West Penn (FE)	*242*	*364*	*285*	*297*	*217*	*36.9%*

*Note: **GREEN** = better than standard; **RED** = worse than standard.*

Performance Standard. An EDC's performance standard is a numerical value that represents the minimal performance allowed for each reliability index for a given EDC. Performance standards are based on a percentage of each EDC's historical performance benchmarks.

OSHA's Form 300A (Rev. 01/2004)

Summary of Work-Related Injuries and Illnesses

Note: You can type input into this form and save it.
Because the forms in this recordkeeping package are "fillable/writable" PDF documents, you can type into the input form fields and then save your inputs using the free Adobe PDF Reader.

Year 20 24

U.S. Department of Labor
Occupational Safety and Health Administration

Form approved OMB no. 1218-0176

All establishments covered by Part 1904 must complete this Summary page, even if no work-related injuries or illnesses occurred during the year. Remember to review the Log to verify that the entries are complete and accurate before completing this summary.

Using the Log, count the individual entries you made for each category. Then write the totals below, making sure you've added the entries from every page of the Log. If you had no cases, write "0."

Employees, former employees, and their representatives have the right to review the OSHA Form 300 in its entirety. They also have limited access to the OSHA Form 301 or its equivalent. See 29 CFR Part 1904.35, in OSHA's recordkeeping rule, for further details on the access provisions for these forms.

Number of Cases

Total number of deaths	Total number of cases with days away from work	Total number of cases with job transfer or restriction	Total number of other recordable cases
0	0	0	0
(G)	(H)	(I)	(J)

Number of Days

Total number of days away from work	Total number of days of job transfer or restriction
0	0
(K)	(L)

Injury and Illness Types

Total number of . . . (M)			
(1) Injuries	0	(4) Poisonings	0
(2) Skin disorders	0	(5) Hearing loss	0
(3) Respiratory conditions	0	(6) All other illnesses	0

Post this Summary page from February 1 to April 30 of the year following the year covered by the form.

Public reporting burden for this collection of information is estimated to average 50 minutes per response, including time to review the instructions, search and gather the data needed, and complete and review the collection of information. Persons are not required to respond to the collection of information unless it displays a currently valid OMB control number. If you have any comments about these estimates or any other aspects of this data collection, contact: US Department of Labor, OSHA Office of Statistical Analysis, Room N-3644, 200 Constitution Avenue, NW, Washington, DC 20210. Do not send the completed forms to this office.

Establishment information

Your establishment name: Citizens' Electric Co

Street: 1775 Industrial Blvd

City: Lewisburg State: PA Zip: 17837

Industry description (*e.g., Manufacture of motor truck trailers*)
Electric Distribution Utility

Standard Industrial Classification (SIC), if known (*e.g., 3715*)

OR

North American Industrial Classification (NAICS), if known (e.g., 336212)
221122

Employment information *(If you don't have these figures, see the Worksheet on the next page to estimate.)*

Annual average number of employees: 19

Total hours worked by all employees last year: 36185

Sign here

Knowingly falsifying this document may result in a fine.

I certify that I have examined this document and that to the best of my knowledge the entries are true, accurate, and complete.

Company executive: [signature] Title: Safety Director

Phone: 570 - 463 - 5814 Date: 1/20/24

Save Input

Annual Tree-Pruning Begins This Week

Citizens' Electric's annual tree-pruning program is expected to begin this week in the Lewisburg area.

Citizens' has awarded its right-of-way maintenance contract to Asplundh Tree Expert, LLC (Asplundh) headquartered in Willow Grove, PA.

Asplundh will attempt to contact customers before beginning pruning work on their properties. The company's tree-pruning professionals possess photo identification and all work vehicles are marked with the company logo.

Asplundh brings experienced personnel, specialized equipment, innovative technology, and logistical resources to help execute successful vegetation management programs. All pruning methods used will follow the ideal method of tree care practice for electric utilities, according to the American National Standards Institute (ANSI).

By keeping the lines clear, Citizens' Electric can provide safer and more reliable service and reduce overall system maintenance costs.

For more information about the company's right-of-way program or planting trees near electric lines,
please contact **Ryan James, Engineering Technician for Citizens' Electric, at (570) 524-2231**.

Tree-Planting Tips

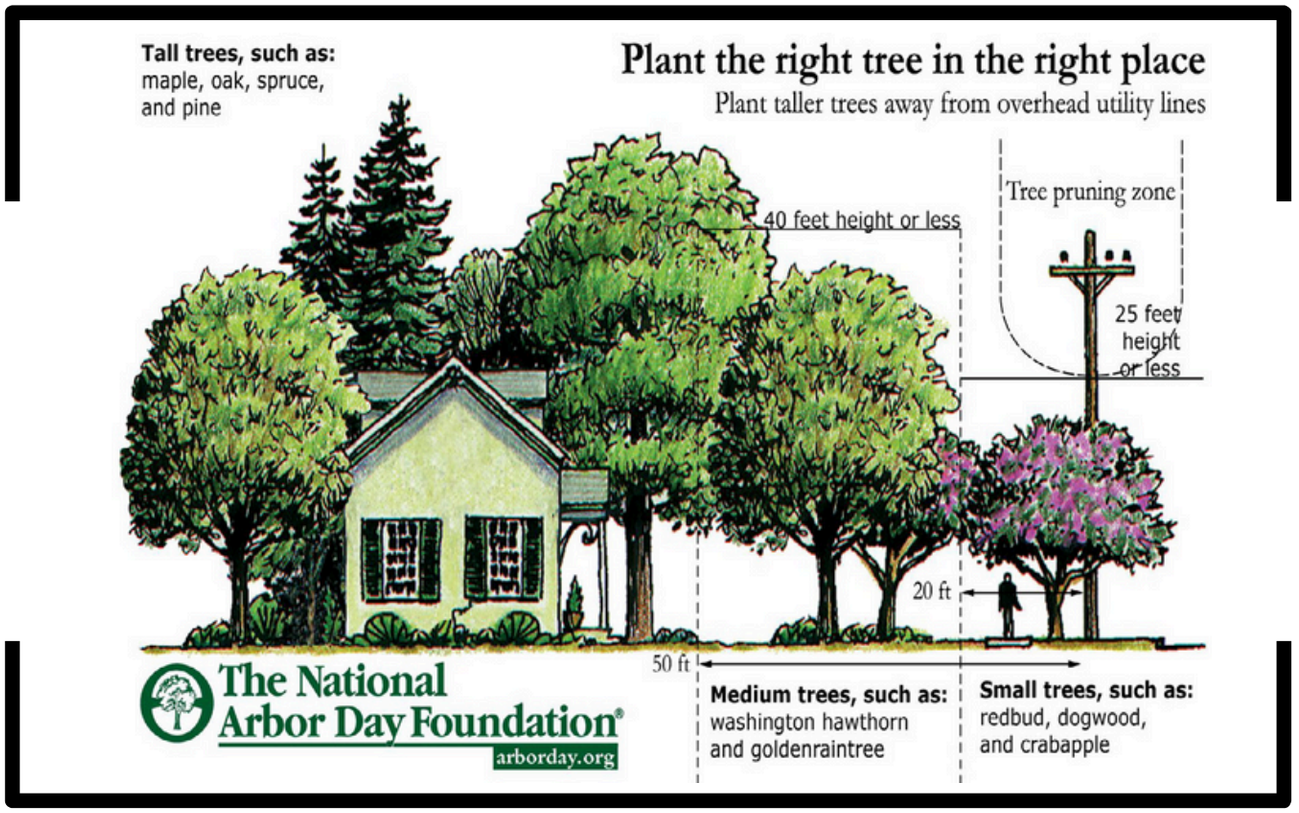
You can help reduce right-of-way maintenance costs by selecting trees appropriate for your yard based on their mature height and proximity to electric lines.

• Plant tall trees far away from overhead lines, and ensure the roots have room to grow and won't interfere with underground lines.

• Plant only smaller trees and shrubs near any electric lines.

• Check to make sure there are no underground power lines where you plan to dig. To do so, call Pennsylvania One Call at 811.

• Trees planted too close to electric lines must be pruned. Your cooperation is appreciated when your trees require pruning. Thank you!



Citizens' Electric Recognized as a Tree Line USA Utility for Over Two Decades

The Arbor Day Foundation's Tree Line USA program helps forward-looking utility providers to be seen as community partners, by outlining best practices in public and private utility arboriculture.

"The Tree Line USA designation reflects our commitment to consistent vegetation-management work using proven techniques," said Citizens' Electric President & CEO Nate Johnson. "Trimming trees adjacent to electric lines is essential to our mission of providing safe, reliable service to our customers. Using methods that promote long-term tree health, minimize property owner impact, and reduce follow-up trimming is the responsible way to accomplish that goal."

This ad is sponsored by Citizens' Electric Co. and Asplundh Tree Expert, LLC

Citizens' Electric Company **Comparison - Actual Capital Expenditures Against Budget** **End of December 2022**

Description	Reimbursement Capital Expense		Material Cost		Labor w/ G&A Allocation		Overhead Cost		Truck Cost		Total Cost		Percent Used To Date	Item Complete Y/N
	Actual	Budget	Actual	Budget	Actual	Budget	Actual	Budget	Actual	Budget	Actual	Budget		
1. General Construction**	$ 7,730	$ -	$ 193,716	$ 205,908	$ 310,643	$ 411,817	$ 369,746	$ 469,029	$ 69,380	$ 67,212	$ 935,755	$ 1,153,966	81%	Y
2. New Transformers	$ -	$ -	$ 87,522	$ 77,000	$ 8,030	$ 9,071	$ 9,146	$ 10,331	$ 3,078	$ 2,139	$ 107,776	$ 98,541	109%	Y
3. New Meters	$ -	$ -	$ 100,575	$ 92,238	$ 20,487	$ 25,425	$ 23,333	$ 28,957	$ 9,594	$ 8,299	$ 153,989	$ 154,919	99%	Y
4. Beagle Club Reconductor WO 20220001	$ -	$ -	$ 21,383	$ 17,774	$ 56,767	$ 32,764	$ 63,436	$ 37,316	$ 11,929	$ 5,347	$ 153,515	$ 93,201	165%	Y
5. Valley View UG WO 20220002	$ -	$ -	$ 71,714	$ 65,500	$ 16,522	$ 11,626	$ 19,814	$ 13,241	$ 4,709	$ 1,897	$ 112,758	$ 92,264	122%	Y
6. Rt 45 Neutral Reconductor Ph 1 WO 20220003	$ -	$ -	$ 5,250	$ 4,537	$ 14,735	$ 15,377	$ 17,598	$ 17,513	$ 3,468	$ 2,510	$ 41,051	$ 39,937	103%	Y
7. Single Phase Recloser Pilot WO 20220406	$ -	$ -	$ 7,944	$ 5,500	$ 1,824	$ 612	$ 2,213	$ 697	$ 204	$ 100	$ 12,185	$ 6,909	176%	Y
8. IT Replacements & Enhancements	$ -	$ -	$ 102,995	$ 95,072	$ -	$ -	$ -	$ -	$ -	$ -	$ 102,995	$ 95,072	108%	Y
9. SUV - #28 2022 Jeep Grand Cherokee to Kevin Nutt	$ -	$ -	$ 43,994	$ 45,000	$ -	$ -	$ -	$ -	$ -	$ -	$ 43,994	$ 45,000	98%	Y
10. SUV - #29 2022 Jeep Grand Cherokee L to Nate Johnson	$ -	$ -	$ 48,245	$ 45,000	$ -	$ -	$ -	$ -	$ -	$ -	$ 48,245	$ 45,000	107%	Y
11. Pickup -#27 2022 Ford F350 4x4	$ -	$ -	$ 52,093	$ 55,000	$ -	$ -	$ -	$ -	$ -	$ -	$ 52,093	$ 55,000	95%	Y
12. Pickup w/Plow - #25 2022 Ford F350 4x4 w/ Plow Pkg	$ -	$ -	$ 52,424	$ 57,500	$ -	$ -	$ -	$ -	$ -	$ -	$ 52,424	$ 57,500	91%	Y
13. Door Security 3980006 - Bldg5doors / 3980007 - Subst 1door	$ -	$ -	$ 16,688	$ 25,000	$ -	$ -	$ -	$ -	$ -	$ -	$ 16,688	$ 25,000	67%	Y
14. Gravel Along W Edge Parking Lot	$ -	$ -	$ 3,990	$ 4,500	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,990	$ 4,500	89%	Y
15. Warehouse Lighting 3900005	$ -	$ -	$ 8,268	$ 7,300	$ 1,899	$ 918	$ 2,128	$ 1,045	$ 156	$ 150	$ 12,451	$ 9,413	132%	Y
16. Warehouse Insulation Ph 1 3900006	$ -	$ -	$ 6,755	$ 6,750	$ -	$ 1,224	$ -	$ 1,394	$ -	$ 200	$ 6,755	$ 9,568	71%	Y
17. Vinyl Siding Replacement 3900007	$ -	$ -	$ 8,632	$ 8,500	$ -	$ -	$ -	$ -	$ -	$ -	$ 8,632	$ 8,500	102%	Y
18. Battery Operated Crimper/Cutter	$ -	$ -	$ 3,169	$ 2,850	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,169	$ 2,850	111%	Y
19. Contingency	$ -	$ -	$ 8,459	$ 20,000	$ -	$ -	$ -	$ -	$ -	$ -	$ 8,459	$ 20,000	0%	Y
Total	$ 7,730	$ -	$ 843,816	$ 840,929	$ 430,907	$ 508,834	$ 507,413	$ 579,523	$ 102,518	$ 87,854	$ 1,876,925	$ 2,017,140	93%	

Citizens' Electric Company **Comparison - Actual Capital Expenditures Against Budget** **End of December 2023**

Description	Reimbursement Capital Expense		Material Cost		Labor w/ G&A Allocation		Overhead Cost		Truck Cost		Total Cost		Percent Used To Date	Item Complete Y/N
	Actual	Budget	Actual	Budget	Actual	Budget	Actual	Budget	Actual	Budget	Actual	Budget		
1. General Construction**	$ 12,010	$ -	$ 156,341	$ 210,915	$ 353,282	$ 421,831	$ 396,239	$ 471,894	$ 89,326	$ 73,640	$ 983,179	$ 1,178,280	83%	Y
2. New Transformers	$ -	$ -	$ 161,811	$ 72,365	$ 10,464	$ 6,675	$ 11,708	$ 7,467	$ 3,399	$ 1,651	$ 187,381	$ 88,158	213%	Y
3. New Meters	$ -	$ -	$ 125,677	$ 166,450	$ 7,220	$ 10,596	$ 8,077	$ 11,853	$ 3,175	$ 3,700	$ 144,149	$ 192,599	75%	Y
4. UG Repl - Terrace & Meadow WO 20230001	$ -	$ -	$ 26,970	$ 29,000	$ 7,695	$ 5,039	$ 8,296	$ 5,637	$ 1,618	$ 880	$ 44,579	$ 40,556	110%	Y
5. Young Rd Reconductor WO 20230002	$ -	$ -	$ 1,377	$ 2,000	$ 5,718	$ 4,409	$ 5,990	$ 4,933	$ 3,327	$ 770	$ 16,413	$ 12,112	136%	Y
6. Smoketown Rd ABS WO 20230003	$ -	$ -	$ 9,769	$ 20,000	$ 4,012	$ 3,735	$ 4,225	$ 4,179	$ 1,866	$ 652	$ 19,872	$ 28,566	70%	N
7. Line Recloser Repl	$ -	$ -	$ 49,170	$ 40,000	$ 15,613	$ 8,189	$ 21,200	$ 9,161	$ 3,282	$ 1,430	$ 89,265	$ 58,780	152%	Y
8. 3ph Recloser Pilot WO 20230010	$ -	$ -	$ 32,388	$ 30,000	$ 6,985	$ 3,150	$ 3,836	$ 3,523	$ 2,694	$ 550	$ 45,904	$ 37,223	123%	Y
9. 3ph PQ Recorder	$ -	$ -	$ 8,746	$ 7,500	$ -	$ -	$ -	$ -	$ -	$ -	$ 8,746	$ 7,500	117%	Y
10. Press/Guy Wire Cutters	$ -	$ -	$ 7,583	$ 6,000	$ -	$ -	$ -	$ -	$ -	$ -	$ 7,583	$ 6,000	126%	Y
11. 2 Way Radio Upgrade	$ -	$ -	$ 47,200	$ 55,000	$ -	$ -	$ -	$ -	$ -	$ -	$ 47,200	$ 55,000	86%	N
12. IT Replacements and Enhancements	$ -	$ -	$ 36,675	$ 59,400	$ -	$ -	$ -	$ -	$ -	$ -	$ 36,675	$ 59,400	62%	N
13. Warehouse Insulation Phase #2 *	$ -	$ -	$ -	$ 10,500	$ -	$ 1,260	$ -	$ 1,409	$ -	$ 220	$ -	$ 13,389	0%	N
14. Break Room Renovation	$ -	$ -	$ 41,435	$ 50,000	$ 1,850	$ -	$ -	$ -	$ -	$ -	$ 43,285	$ 50,000	87%	Y
15. Track Loader	$ -	$ -	$ 82,044	$ 95,000	$ -	$ -	$ -	$ -	$ -	$ -	$ 82,044	$ 95,000	86%	Y
16. Tilt Deck Trailer #3920024 Truck #108	$ -	$ -	$ 10,190	$ 17,000	$ -	$ -	$ -	$ -	$ -	$ -	$ 10,190	$ 17,000	60%	Y
17. Contingency	$ -	$ -	$ 36,188	$ 20,000	$ -	$ -	$ -	$ -	$ -	$ -	$ 36,188	$ 20,000	181%	Y
Total	$ 12,010	$ -	$ 833,564	$ 891,130	$ 412,839	$ 464,884	$ 459,571	$ 520,056	$ 108,688	$ 83,493	$ 1,802,653	$ 1,959,563	92%	

Citizens' Electric Company **Comparison - Actual Capital Expenditures Against Budget** **End of December 2024**

Description	Reimbursement Capital Expense		Material Cost		Labor w/ G&A Allocation		Overhead Cost		Truck Cost		Total Cost		Percent Used To Date	Item Complete Y/N
	Actual	Budget	Actual	Budget	Actual	Budget	Actual	Budget	Actual	Budget	Actual	Budget		
1. General Construction**	$ 81,315	$ -	$ 203,466	$ 207,487	$ 395,800	$ 414,974	$ 444,212	$ 483,183	$ 90,849	$ 84,378	$ 1,053,012	$ 1,190,022	88%	Y
2. New Transformers	$ -	$ -	$ 118,783	$ 109,361	$ 5,023	$ 6,403	$ 5,916	$ 7,455	$ 1,896	$ 1,827	$ 131,618	$ 125,046	105%	Y
3. New Meters	$ -	$ -	$ 180,324	$ 75,039	$ 9,661	$ 5,560	$ 11,251	$ 6,474	$ 4,591	$ 2,261	$ 205,827	$ 89,334	230%	Y
4. Phase 1 Reclosers WO 20240007,8,9,10,11,12,13	$ -	$ -	$ 43,897	$ 47,600	$ 13,504	$ 10,694	$ 13,829	$ 12,451	$ 3,035	$ 2,174	$ 74,265	$ 72,919	102%	Y
5. Phase 3 Reclosers (Sub Station) WO 20240110	$ -	$ -	$ 60,402	$ 26,000	$ 2,945	$ 5,092	$ 3,287	$ 5,929	$ 62	$ 1,035	$ 66,695	$ 38,056	175%	Y
6. Pheasant Ridge & James Rds Relocation WO 20240002	$ -	$ -	$ 99,516	$ 70,000	$ 20,896	$ 19,096	$ 22,207	$ 22,234	$ 3,688	$ 3,883	$ 146,306	$ 115,213	127%	Y
7. Creekside Ln UG Boring WO 20240001	$ -	$ -	$ 28,274	$ 20,000	$ 9,428	$ 2,546	$ 11,666	$ 2,965	$ 2,270	$ 518	$ 51,637	$ 26,029	198%	Y
8. Hydraulic Stick Saw	$ -	$ -	$ 2,060	$ 2,500	$ -		$ -		$ -		$ 2,060	$ 2,500	82%	Y
9. Additional Tools	$ -	$ -	$ -	$ 1,500	$ -		$ -		$ -		$ -	$ 1,500	0%	N
10. IT Replacement & Enhancement	$ -	$ -	$ 28,061	$ 29,325	$ -		$ -		$ -		$ 28,061	$ 29,325	96%	Y
11. Insulate Warehouse - Phase #2	$ -	$ -	$ 14,699	$ 16,000	$ -	$ 1,910	$ -	$ 2,223	$ -	$ 388	$ 14,699	$ 20,521	72%	Y
12. Engineering Office Renovation	$ -	$ -	$ 4,829	$ 5,000	$ -		$ -		$ -		$ 4,829	$ 5,000	97%	Y
13. Phone System Upgrade	$ -	$ -	$ 5,197	$ 7,000	$ -		$ -		$ -		$ 5,197	$ 7,000	74%	Y
14. Substation Shed Replacement	$ -	$ -	$ 17,788	$ 18,000	$ -		$ -		$ -		$ 17,788	$ 18,000	99%	Y
15. Bucket Truck	$ -	$ -	$ 278,319	$ 290,000	$ -		$ -		$ -		$ 278,319	$ 290,000	96%	Y
16. Auger for Track Loader	$ -	$ -	$ 8,948	$ 6,500	$ -		$ -		$ -		$ 8,948	$ 6,500	138%	Y
17. Contingency	$ -	$ -	$ 10,822	$ 20,000	$ -		$ -		$ -		$ 10,822	$ 20,000	54%	Y
Total	$ 81,315	$ -	$ 1,105,385	$ 951,312	$ 457,257	$ 466,275	$ 512,368	$ 542,914	$ 106,389	$ 96,464	$ 2,100,084	$ 2,056,965	102%	

CITIZENS' ELECTRIC COMPANY
2025 DISTRIBUTION LUMP SUM

BID PROPOSAL

1. Lump Sum Price Only
(Primary & Secondary Pruning, Reclear/Spray & Removals with Permission Granted) $ 809,092.54 PRICE

The following "Removal Pricing" shall be for; Removals as part of normal trimming cycle, where the customer/Citizens' Electric decides to remove rather than trim. Also, other removals agreed upon during the course of work (hazard trees, Ash Tree removals etc.)

2. Removals with
6.1" - 12" STUMP DIAMETER $ 316.68 PRICE/TREE REMOVED

3. Removals with
12.1" - 18" STUMP DIAMETER $ 594.35 PRICE/TREE REMOVED

4. Removals with
18.1 - 24" STUMP DIAMETER $ 1,266.84 PRICE/TREE REMOVED

5. Removals with
24.1" AND ABOVE STUMP DIAMETER $ T&M PRICE/TREE REMOVED

6. Re-clear in Right of Way $ 6,002.00 PRICE PER ACRE

7. Please Provide The Hourly Rates For The Following:

1. Foreman	$ 51.71	6. Chipper Truck	$ 16.95
2. First Class Climber	$ 48.48	7. Chipper	$ 6.80
3. Ground Hand	$ 40.28	8. Stump Grinder	$ 25.79
4. Bucket Truck (70')	$ 35.20	9. Log Truck (2 axle)	$ 28.78
5. Chainsaw	$ Inc	10. _____ (Other, specify)	$

[redacted] Contractor

2/11/2025 Date

[redacted] Signature

CITIZENS' ELECTRIC COMPANY

2025 DISTRIBUTION LUMP SUM

BID PROPOSAL

1. Lump Sum Price Only
(Primary & Secondary Pruning, Reclear/Spray & Removals with Permission Granted) $ 559,500.00 PRICE

The following "Removal Pricing" shall be for; Removals as part of normal trimming cycle, where the customer/Citizens' Electric decides to remove rather than trim. Also, other removals agreed upon during the course of work (hazard trees, Ash Tree removals etc.)

2. Removals with
6.1" - 12" STUMP DIAMETER $ 225.00 PRICE/TREE REMOVED

3. Removals with
12.1" - 18" STUMP DIAMETER $ 355.00 PRICE/TREE REMOVED

4. Removals with
18.1 - 24" STUMP DIAMETER $ 745.00 PRICE/TREE REMOVED

5. Removals with
24.1" AND ABOVE STUMP DIAMETER $ 675.00 PRICE/TREE REMOVED

6. Re-clear in Right of Way $ 300.00 PRICE PER ACRE

7. Please Provide The Hourly Rates For The Following:

1. Foreman	$ 57.43	6. Chipper Truck	$ 17.50
2. First Class Climber	$ 46.79	7. Chipper	$ 12.18
3. Ground Hand	$ 39.35	8. Stump Grinder	$ 23.33
4. Bucket Truck	$ 29.98	9. Log Truck	$ 35.03
5. Chainsaw	$ 1.00	10. 70' Bucket (Other, specify)	$ 35.03

[redacted] — Contractor

02/14/25 — Date

[redacted] — Signature

CITIZENS' ELECTRIC COMPANY
2025 DISTRIBUTION LUMP SUM

BID PROPOSAL

1. Lump Sum Price Only
(Primary & Secondary Pruning, Reclear/Spray & Removals with Permission Granted) $ 345,000.00 PRICE

The following "Removal Pricing" shall be for; Removals as part of normal trimming cycle, where the customer/Citizens' Electric decides to remove rather than trim. Also, other removals agreed upon during the course of work (hazard trees, Ash Tree removals etc.)

2. Removals with
6.1" - 12" STUMP DIAMETER $ 71.00 PRICE/TREE REMOVED

3. Removals with
12.1" - 18" STUMP DIAMETER $ 152.00 PRICE/TREE REMOVED

4. Removals with
18.1 - 24" STUMP DIAMETER $ 380.00 PRICE/TREE REMOVED

5. Removals with
24.1" AND ABOVE STUMP DIAMETER $ 1,245.00 PRICE/TREE REMOVED

6. Re-clear in Right of Way $ 3,000.00 PRICE PER ACRE

7. Please Provide The Hourly Rates For The Following:

1. Foreman	$ 53.50	6. Chipper Truck	$ 15.25
2. First Class Climber	$ 50.75	7. Chipper	$ 7.00
3. Ground Hand	$ 40.77	8. Stump Grinder	$ 36.38
4. Bucket Truck	$ 31.42	9. Log Truck	$ 51.38
5. Chainsaw	$ 1.25	10. remote mower (Other, specify)	$ 46.45

[redacted] Contractor

2/14/25 Date

[redacted] Signature

CITIZENS' ELECTRIC COMPANY
2025 DISTRIBUTION LUMP SUM

BID PROPOSAL

1. Lump Sum Price Only
(Primary & Secondary Pruning, Reclear/Spray & Removals with Permission Granted) $ 324,900.00 PRICE

The following "Removal Pricing" shall be for; Removals as part of normal trimming cycle, where the customer/Citizens' Electric decides to remove rather than trim. Also, other removals agreed upon during the course of work (hazard trees, Ash Tree removals etc.)

2. Removals with
6.1" - 12" STUMP DIAMETER $ 150.00 PRICE/TREE REMOVED

3. Removals with
12.1" - 18" STUMP DIAMETER $ 330.00 PRICE/TREE REMOVED

4. Removals with
18.1 - 24" STUMP DIAMETER $ 530.00 PRICE/TREE REMOVED

5. Removals with
24.1" AND ABOVE STUMP DIAMETER $ 1500.00 PRICE/TREE REMOVED

6. Re-clear in Right of Way $ 3000.00 PRICE PER ACRE

7. Please Provide The Hourly Rates For The Following:

1. Foreman	$ 65.00	6. Chipper Truck	$ 15.00
2. First Class Climber	$ 60.00	7. Chipper	$ 20.00
3. Ground Hand	$ 55.00	8. Stump Grinder	$ 60.00
4. Bucket Truck	$ 70.00	9. Log Truck	$ 60.00
5. Chainsaw	$ 7.00	10. pickup (Other, specify)	$ 10.00

[redacted]
Contractor

2/5/25
Date

[redacted]
Signature

CITIZENS' ELECTRIC COMPANY

2025 DISTRIBUTION LUMP SUM

BID PROPOSAL

1. Lump Sum Price Only — $ 172549.23
(Primary & Secondary Pruning, Reclear/Spray & Removals with Permission Granted) — PRICE

The following "Removal Pricing" shall be for; Removals as part of normal trimming cycle, where the customer/Citizens' Electric decides to remove rather than trim. Also, other removals agreed upon during the course of work (hazard trees, Ash Tree removals etc.)

2. Removals with 6.1" - 12" STUMP DIAMETER — $ 140.61 PRICE/TREE REMOVED

3. Removals with 12.1" - 18" STUMP DIAMETER — $ 217.42 PRICE/TREE REMOVED

4. Removals with 18.1 - 24" STUMP DIAMETER — $ 699.90 PRICE/TREE REMOVED

5. Removals with 24.1" AND ABOVE STUMP DIAMETER — $ 1105.87 PRICE/TREE REMOVED

6. Re-clear in Right of Way — $ 3248.22 PRICE PER ACRE

7. Please Provide The Hourly Rates For The Following:

1. Foreman	$ 58.13	6. Chipper Truck	$ 15.44
2. First Class Climber	$ 52.42	7. Chipper	$ 7.65
3. Ground Hand	$ 43.34	8. Stump Grinder	$ 12.38
4. Bucket Truck	$ 27.30	9. Log Truck	$ 44.27
5. Chainsaw	$ 1.25	10. Remote Mower (Other, specify)	$ 35.59

[redacted] — Contractor

02/12/2025 — Date

[redacted] — Signature

Citizens' Statement No. 4R

BEFORE
THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	**:**	
	:	
v.	**:**	**Docket No. R-2025-3054394**
	:	
Citizens' Electric Company of Lewisburg, PA	**:**	

REBUTTAL TESTIMONY
AND EXHIBITS

OF

NATHAN JOHNSON

ON BEHALF OF

CITIZENS' ELECTRIC COMPANY OF LEWISBURG, PA

AUGUST 13, 2025

BEFORE
THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	**Docket No. R-2025-3054394**
	:	
Citizens' Electric Company of Lewisburg, PA	:	

REBUTTAL TESTIMONY OF NATHAN JOHNSON
ON BEHALF OF CITIZENS' ELECTRIC COMPANY OF LEWISBURG, PA

Q. Please state your name and business address.

A. My name is Nathan (Nate) Johnson. My business address is 1775 Industrial Blvd., Lewisburg, Pennsylvania.

Q. Are you the same Nathan Johnson who previously submitted Direct Testimony in this proceeding on behalf of Citizens' Electric Company of Lewisburg, PA ("Citizens'" or "Company")?

A. Yes. Terms defined in my direct testimony have the same meaning in this Rebuttal Testimony.

Q. What is the purpose of your testimony today?

A. My testimony will respond to the Direct Testimony of the following witnesses:

- Witnesses Keller, Walters, and Farr, representing Bureau of Investigation and Enforcement ("I&E"), Office of Consumer Advocate ("OCA"), and the OSBA"), respectively, regarding their opposition to the Company's proposed Performance and Small Size adjustments used in its return on equity ("ROE") calculations.
- Witnesses Keller, Walters, and Farr, representing I&E, OCA, and OSBA, respectively, regarding their proposed adjustments to the Company's Expense Claims.

- OCA Witness Wise, regarding her recommendations for the Company to implement various changes to its practices related to customer payment arrangements.
- Kelly Road Solar, LLC, Lancaster Avenue Solar, LLC and Twilight Renewables, LLC ("Solar Projects") Witnesses Nolt and Lucas, regarding their opposition to the Company's proposed change to the definition of Billing Demand in its tariff.

PERFORMANCE ADJUSTMENT

Q. Please summarize the parties' positions regarding the Company's proposed performance adjustment. (I&E Statement No. 2 at 48, OCA Statement No. 2 at 78, OSBA Statement No. 1 at 13)

A. Witnesses Walters, Keller, and Farr, representing OCA, I&E, and OSBA, respectively, all recommend that the proposed performance adjustment factor be removed.

Q. How do you respond to this recommendation?

A. Their testimonies, in essence, all imply that the Company is asking for a bonus as a reward for simply meeting its regulatory obligations[1]. This implication ignores the specific examples provided by the Company of performance that *exceeds* regulatory requirements. None of the witnesses dispute any of the examples provided, nor do they comment explicitly on whether the Company's performance exceeds required performance. All three witnesses assert that performance adjustments are not guaranteed, that simply meeting obligations does not warrant a performance obligation, and that they do not believe the Company should be allowed one. The Company agrees that there is no obligation or entitlement to performance adjustments, and that satisfactory performance does not

[1] I&E Statement No. 1 at 51; OCA Statement No. 2 at 79; OSBA Statement No. 1 at 14.

warrant an adjustment. The proposed adjustment, however, is based on *exceptional* performance provided above and beyond regulatory requirements.

Q. Please explain how the basis for the performance adjustment provided in your Direct Testimony represents exceptional performance.

A. The Company's examples of exceptional performance, which were initially presented in my Direct Testimony[2], are further described below:

- Low Customer Complaints

  The Company has not had a single formal or justified informal complaint since its last rate case. Of the informal complaints that were filed, 18 were for payment arrangements and only four were for other issues. This demonstrates the rarity with which customers are dissatisfied with the service that we provide to them, and our record of performance since none of the informal complaints were found by BCS to be justified.

- Favorable Customer Feedback

  Customer satisfaction is not a regulatory requirement, and it is commonly accepted that consumers are more likely to report dissatisfaction than satisfaction. A customer satisfaction rating of over 90% demonstrates that the Company routinely exceeds customer expectations.

- Customer Support Calls

  The Company carefully manages its customer service functions and phone/IVR systems to ensure that customers can always reach an individual when needed. While many companies seek to reduce human interaction in their customer service functions,

[2] Citizens' Statement No. 4 at 9.

the Company recognizes our ratepayers' desire to have an employee available to answer the phone and maintains a system that provides for this service.

- Energizing New Service Locations

  The Company's average time to energize a new service location is less than many other utilities' minimum lead time for scheduling new service energizations. Again, this is based on feedback from our customers and their contractors that they prefer the Company's management of its schedule over other electric distribution companies ("EDC") processes, and the Company working to accommodate our customers and their contractors.

- Reliability

  The Company routinely exceeds the Pennsylvania Public Utility Commission ("PUC") benchmark standards for reliability and, in an absolute comparison with peer EDCs, is consistently one of the most reliable in the state. Service reliability cannot be guaranteed, but the Company is obviously committed to providing exceptional service.

- Zero Reportable Injuries

  Safety of employees, customers and the public go hand-in-hand, so the Company's absence of reportable injuries, not only for 2024, but for the prior decade, indicates an exceptional commitment to safety. This also minimizes costs associated with insurance and damage claims, which can be significant when injuries or accidents occur.

- Technology Adoption

  The Company adopts technology as it identifies opportunities to improve operations or customer service, rather than to fulfill any regulatory requirement. One example of this is the drone inspection program that we are pursuing. Another is providing SmartHub

for our customers. This improves efficiency and keeps customers informed and satisfied.

- Pole Attachments

  The Company has voluntarily undergone an extensive review of its pole attachment fees and annually reviews its attachment licenses, rates and field data to ensure that customers are not burdened by regulatory obligations to share pole space.

- Tree Line Designation

  The Company is one of only 4 designated Tree Line Utilities in Pennsylvania, and the second longest standing. Only 143 utilities nationwide are recognized as Tree Line Utilities. Tree Line designation is indicative of the Company's efforts to pursue best practices that maximize cost efficiency, customer satisfaction, and environmental stewardship.

- Capital Investment

  While capital investment is necessary for all utilities, the Company has continued to fund adequate investment in its system without burdening customers with an additional Distribution System Improvement Charge.

Q. Did the Commission accept a performance adjustment for Citizens' in prior proceedings?

A. Yes, the Commission acknowledged the adjustment in our fully-litigated 2019 proceeding. We urge the Commission to recognize the value of regulatory consistency and certainty by adopting a similar approach in this proceeding.

SIZE ADJUSTMENT

Q. Please summarize the parties' recommendations regarding the Company's proposed size adjustments. (I&E Statement No. 2 at 44, OCA Statement No. 2 at 80, OSBA Statement No. 1 at 14)

A. Witnesses Walters, Keller, and Farr, representing OCA, I&E, and OSBA, respectively, all recommend that the proposed performance adjustment factor be removed. They also contest various other portions of Mr. D'Ascendis' testimony, which I will defer to him to defend in his rebuttal. OSBA Witness Farr also contests the Company's argument for the risk associated with the loss of a large customer.

Q. How do you respond to Witness Farr's assessment of the risk of losing a large customer?

A. Witness Farr acknowledges that the loss of a large customer could reduce the Company's revenues[3]. He goes on to suggest that Company could equally benefit from a new, large customer and that, in general, new customers might offset any losses. Recent history indicates that, in the Company's case, the losses outweigh the gains. The Company has lost several major customers in recent years, and large net metering installations continue to increase in number. In contrast, new load has failed to offset or exceed these losses.

Q. Did the Commission accept a size adjustment for Citizens' in prior proceedings?

A. Yes, the Commission acknowledged the adjustment in our fully-litigated 2019 proceeding. We urge the Commission to recognize the value of regulatory consistency and certainty by adopting a similar approach in this proceeding.

[3] OSBA Statement No. 1 at 21

EXPENSE CLAIMS

Q. Please explain OCA's proposed adjustment to overhead line maintenance. (OCA Statement No. 1 at 16)

A. OCA Witness Meyer opposes the Company's projected increase in costs under FERC account 593[4]. He proposes that historical growth rates be applied, ignoring the Company's explanation for the projected increase.

Q. Do you agree with this recommendation?

A. No, the Company's projected expenses are well supported. Witness Meyer suggests that the Company has offered only a "bald assertion[5]" that costs will increase. To the contrary, the Company explained its reasoning at length, providing three maintenance activities that contribute to the increase and even providing copies of tree trimming bids as evidence. Below, I provide further explanation of each component of the increase:

- Vegetation Management

  Vegetation management represents a substantial maintenance expense for all Pennsylvania EDCs. With trees being, by volume, the most abundant hazard to overhead lines in our service area, it should be no surprise that it is also our largest maintenance expense. Bids for the 2025 trimming contract clearly indicate that prices can be expected to rise dramatically in coming years. To be knowingly under budget for expected tree trimming expenses would be to risk significant consequences to service reliability and employee and public safety.

[4] OCA Statement No. 1, at 16.
[5] OCA Statement No. 1 at 18.

- Drone Inspections

  The Company's drone inspection program is new in 2025 after a 2023 pilot program proved its usefulness. New programs come at a cost, and while it is expected that this program will yield long-term savings, Citizens' will incur expenses in the Future Test Year ("FTY") and Fully Projected Future Test Year ("FPFTY") for the drone program that were not incurred in 2024 (the Historic Test Year ("HTY")).

- Pole Inspections

  The Company's pole inspection program is well established and has been reviewed and approved by the PUC as part of our Biennial Inspection and Maintenance Plan. The Company knows, in advance, how many poles will be inspected and can predict with reasonable accuracy the cost to have them inspected.

  Attached as Exhibit__(NJ-1R) is the annual breakdown of the Account 593 costs.

Q. Mr. Meyer testifies that the Company has not demonstrated that it engages in cost control. Do you have any comments?

A. Yes. In conjunction with his discussion of Account 593, Mr. Meyer comments that he is "struck that there is no discussion of how the Company is exercising cost control.[6]" The Company was asked to provide, in I&E-RE-14-D, an explanation of why costs increased, and the Company did that. Every expense incurred by the Company is also reviewed for cost containment opportunities, from $350,000 tree contracts down to sticky notes in the office. The Company does not describe detailed cost containment activities for its other expense claims, yet Mr. Meyer does not contest these. To demonstrate the Company's

[6] OCA Statement No. 1, at 18.

commitment to cost containment, I will address cost containment activities related to each of the line maintenance expense categories in question:

- Vegetation Management

  Unlike many larger EDCs, which contract vegetation management by circuit or substation and pay per mile, the Company provides a specific layout of desired tree trimming work each year. This allows for a firm-bid contract that is specific to the work performed; bidders do not have to price as much risk into their proposals because they are provided with an explicit work plan. To further increase efficiency, the Company pairs its overhead visual line inspection program with trimming layout, supporting two maintenance goals with one effort.

- Drone Inspections

  The Company piloted its drone inspection plan in 2023 in order to evaluate its effectiveness before committing to a multi-year program. We do expect the program to yield savings, but over a course of several years, not instantly, as Witness Meyer implies it they should. As with Vegetation Management, we also look to gain efficiency with the program in areas outside of its specific purpose. The inspection will provide improved pole location coordinates in remote areas, allow for auditing of pole hardware, and reduce site visits to remote poles via high-resolution imagery . Again, however, these efficiencies will take time to reflect in expenses.

- Pole Inspections

  The Company competitively bids pole inspections and has frequently investigated alternative methods of inspection, and approached vendors about consolidating services such as pole auditing, inspection and drone inspection. Pole inspections have

proven their effectiveness, and the Company's low rate of 'reject' poles shows the benefits they provide to our customers.

WAGE AND SALARY (PAYROLL) EXPENSES

Q. Did OCA propose any adjustment to the Company's Wage & Salary expenses. (OCA Statement No. 1 at 13)

A. OCA Witness Meyer recommends that the Company's payroll expenses be adjusted to reflect an increase of 4%, and that the salaries of the Company's proposed additional hires be removed entirely, resulting in a total reduction in payroll expenses of $116,567.

Q Do you agree with this adjustment?

A No, the proposed adjustment by Witness Meyer ignores the Company's well supported rationale for the increase in payroll expenses and proposes, instead, to replace it with a 4% annual adjustment based on his "…experience that a typical range for annual payroll increases are between 3.5 to 4% per year"[7] without providing any further evidence in support.

Q. Please explain why you believe it is appropriate to include the two additional hires in the Company's revenue requirement.

A. The Company has an obligation to evaluate its workforce and develop a hiring plan to meet the needs of the business and its ratepayers. The two hires in question are replacements for line technicians expected to retire in the years following 2026. Line workers are trained through a rigorous, multi-year apprenticeship which typically requires four to five years to complete. In order to maintain an adequate staff of fully trained line workers, the Company must hire new line workers four years in advance of expected vacancies. The two proposed

[7] OCA Statement No. 1 at 15.

hires are necessary to maintain safe and reliable operation of the Company's distribution system and should thus be included in the revenue requirement for this filing.

Q. Is the 4% annual adjustment of overall payroll expenses by Witness Meyer reasonable?

A. No, the Company has provided extensive support of its Wage and Salary plan, both in its Direct Testimony and responses to various discovery requests by the parties. Based on the study, several of our positions required adjustments to better reflect market conditions, which we are making over two years (the FTY and FPFTY). Our projections also include merit-based increases that we project based on the developmental paths of employees. Finally, we included the impact of an annual base compensation adjustment, which used historic adjustments to project the FPFTY adjustment. Witness Meyer, on the other hand, has provided no support for his adjustment other than his personal experience of 'typical' increases. He rolls all compensation adjustments into his 4% estimate, without examining or disputing our evidence of the separate components that support the FPFTY payroll levels.

PAYMENT PLANS

Q. Does OCA raise concerns with the Company's practices related to customer payment plans? (OCA Statement No. 4 at 10)

A. Yes, OCA Witness Wise expresses concern that the Company does not have metrics in place to track the success of payment arrangements. Witness Wise goes on to state that "[i]n [her] professional opinion, the absence of such oversight may reflect a lack of due

diligence and raise concerns about the company's ability to manage financial risk or make informed decisions regarding customer repayment strategies[8]."

Q. Please respond to these concerns.

A. Ignoring the disparaging tone of Witness Wise's comment, it is also entirely subjective and unsubstantiated. Witness Wise describes her professional background as working with a large telecommunications company. While this is relevant, the practices of a national corporation should not be projected onto a function performed by a single individual at Citizens' Electric, nor is it appropriate to imply that a lack of formalized metrics represents a lack of oversight.

Citizens' actively manages its billing and collection activities, including payment arrangement status. We monitor and follow up on late payments, undertaking outreach to customers who have fallen behind. We work with our payment-troubled customers to connect them with resources to help them. We are financially prudent in our operations.

Q. Does OCA make any recommendations related to payment plans? If so, please explain?

A. Yes, OCA Witness Wise recommends that the Company establish metrics for measuring the success of payment plans, clearly communicate payment options to customers, and goes on to make several specific suggestions about how these changes should be accomplished.

Q. Please provide the Company's position on each of the recommendations made.

A. 1) <u>The Company should establish metrics for measuring success.</u>[9]

The Company's manager of customer service individually assesses, negotiates, and approves each payment arrangement, and is equally personally aware of the success of

[8] OCA Statement No. 4 at 12.
[9] *Id.* at p 12, ln 7.

failure of each arrangement. As provided in the Company's response to OCA-VI-17, there were 82 customers on payment arrangements as of June 9, 2025. Complex metrics are not necessary for a single individual to assess the success of a relatively small number of arrangements. Furthermore, Witness Wise assumes that payment arrangements fail because the customer cannot afford the payment. In my experience, factors other than the inability to pay are often the reasons that the arrangements fail. Finally, contrary to Witness Wise's implication that the Company does document how Federal Poverty Income Guidelines ("FPIG") are used and terms calculated, the Company provided this information to OCA in its response to OCA-VI-16.

2) The Company should make sure payment options are clearly communicated.[10]

The Company does this already, and Witness Wise does not suggest anywhere in her testimony that customers are inadequately informed of their options, so no change is necessary.

3) The Company should maintain internal controls.[11]

The small quantity of customers enrolled in payment plans allows the Company to assess requests individually and use its discretion to "tailor payment obligations in line with a customer's financial means[12]" as acknowledged by Witness Wise. Rather than providing additional benefits to customers, the Company believes that establishing rigid controls would limit the ability of the Company to accommodate customers' needs in a manner mutually beneficial to the individual customer, and other ratepayers in general.

[10] *Id.* at p 12, ln 10.
[11] *Id.* at p 12, ln 13.
[12] *Id.* at 11.

4) The Company should consider separating plans by income levels.[13]

This suggestion would result in breaking payment arrangements into quantities too small for statistically relevant analysis. As of July 22, 2025, there are 63 customers on payment arrangements, broken down into the four FPIG categories used, there would be 15 or less arrangements in some categories, rendering any analysis broken out by income level volatile and ineffective. Based on OCA's line of questioning in its discovery requests, such a breakdown may correspond well to their established means of analyzing payment arrangement programs but would provide little value to the Company or its ratepayers.

5) The Company should routinely evaluate its payment arrangements.[14]

As with (2), above, the Company already does this, and Witness Wise does not suggest otherwise except to imply so with her recommendation. No change is necessary.

Q. Please summarize your responses to Witness Wise.

A. The Company's payment plan process is working well and does not need the "enhancements" suggested by the OCA. Our staff is small and keeps watch over the billing and collection processes, including payment plans. We adhere to the Commission's guidelines. No additional protocols, policies, or reporting are needed.

[13] *Id.* at 12.
[14] *Id.* at p 12, ln 15.

BILLING DEMAND FOR CUSTOMER-GENERATORS

Q. Have you reviewed the Direct Testimony provided by Mr. Nolt and Mr. Lucas on behalf of Kelly Road Solar, LLC, Lancaster Avenue Solar LLC, and Twilight Renewables, LLC?

A. Yes. Like any change in rate application or design, the proposal will impact each customer separately depending on their circumstances. As the utility, we are seeking to treat all customers fairly and to charge our customers an appropriate portion of the distribution costs. We also believe that categorizing customer-generators appropriately for the default service rates is necessary to prevent GSSR-1 customers from paying unreasonable subsidies to sophisticated businesses that install on-site generation.

Q. Is the Company instituting a new demand charge for generators? (SP Statement No. 1 at 12, 13)

A. No, Mr. Nolt's testimony misconstrues the nature of the tariff change. All non-residential customers currently pay a demand charge, including customer-generators. The Company's proposed tariff change will result in increased demand charges for some customer-generators, particularly those generators that are producing substantially more than they consume in real time, or that do not offset any non-generation load at all.

Q. Do you agree that this change will prevent any new net-metered generation of greater than 400 kW[15] Gross Generator Capacity? (SP Statement No. 1 at 5)

A. No, it may be true that this change will dissuade Twilight Renewables from further projects of this size in the Company's service area, but the viability of Mr. Nolt's projects is not representative of all potential customer-generators. For example, if a GLP-3 customer with

[15] For the purposes of this testimony, kW refers to *alternative current kilowatts (*kW(AC)) unless otherwise noted.

demand already exceeding 400 kW were to install a solar array to offset a portion of their load, they would see little, if any, increase in demand charges, no change in energy rates, and may achieve substantial savings. Mr. Nolt's business model appears to focus on one business strategy; however, other strategies exist where a customer-generator takes advantage of net metering.

Q. Please discuss your understanding of Mr. Nolt's projects in the Citizens' territory.

A. In discovery, we asked Mr. Nolt for more information regarding the projects that he has completed or that are under development in our territory. Attached as Exhibit__(NJ-2R) are discovery responses to Citizens-SP II-1 and 8 that describe the projects. One of the completed projects is owned by the host customer at an agricultural site. For the other five, the host customer will provide Mr. Nolt and/or his investors with a roof lease to install and operate the solar array. Mr. Nolt indicates that the size is based primarily on the available roof space.

Q. You previously stated that Twilight Renewables pursues a specific business model. Do other customer-generators use different business strategies?

A. Yes. The customer has the option to install any size of generation for net metering, up to 3 MW. Some customer-generators determine the size of their solar array based on the amount of rooftop area or land that is available or conducive to solar. Other customers may pursue solar generation due to non-monetary motivations such as sustainability accreditations. Other customer-generators pursue the strategy of installing large generation facilities with little or no load at the site.

Moreover, customer-generators are not limited to solar generation. Other fuel options have much higher availability factors.

Q. Can you calculate the distribution cost impact of the proposal for other business strategies?

A. Yes. The table below, supported by Exhibit NJ-3R shows how distribution cost responsibility may be impacted for other strategies. For this example, I am focusing solely on the monthly customer and demand charges, without any kWh distribution charges included. I also am assuming that the customer's onsite usage peak does not occur coincident with operation of the on-site generation. Finally, I have used the demand rates that reflect approval of the Billing Demand definition, as calculated by Mr. Gorman's rebuttal testimony (Citizens' Statement No. 1R at 5).

	Combined Customer & Demand Charges			
Customer-Generator Description	Existing Demand / Present Rates	Existing Demand / Proposed Rates	Proposed Demand / Proposed Rates	Monthly / Annual Difference
50 kW Import 50 kW Gen GLP-1	$ 176 /mo $ 2,108 /yr	$ 183 /mo $ 2,194 /yr	$ 211 /mo $ 2,526 /yr	$ 28 /mo $ 332 /yr
50 kW Import 150 kW Gen GLP-1	$ 176 /mo $ 2,108 /yr	$ 183 /mo $ 2,194 /yr	$ 590 /mo $ 7,074 /yr	$ 407 /mo $ 4,880 /yr
150 kW Import 75 kW Gen GLP-3	$ 741 /mo $ 8,896 /yr	$ 958 /mo $ 11,492 /yr	$ 958 /mo $ 11,492 /yr	$ 0 /mo $ 0 /yr
400 kW Import 500 kW Gen GLP-1	$ 1,182 /mo $ 14,189 /yr	$ 1,203 /mo $ 14,436 /yr	$ 1,916 /mo $ 22,992 /yr	$ 713 /mo $ 8,556 /yr
5 kW Import 480 kW Gen GLP-1	$ 35 /mo $ 416 /yr	$ 40 /mo $ 479 /yr	$ 1,840 /mo $ 22,082 /yr	$ 1,800 /mo $ 21,603 /yr
5 kW Import 1000 kW Gen GLP-1	$ 35 /mo $ 416 /yr	$ 40 /mo $ 479 /yr	$ 3,811 /mo $ 45,732 /yr	$ 3,771 /mo $ 45,253 /yr

As this demonstrates, the impact of the change depends on the customer-generator's configuration. The example that is especially troubling is the distribution cost responsibility for the customer-generator with 1000 kW Gross Generator Capacity and only 5 kW Imported Demand at the current rates. While we do not have customer-generators

like this yet, we are aware of many such projects in other electric distribution company territories. It is prudent to implement the requested change now so we can ensure appropriate distribution charges if a customer-generator chooses to interconnect a project like this in our territory.

Q. Mr. Johnson, have you reviewed Mr. Nolt's "case study" provided with his testimony?

A. Yes, Mr. Nolt's case study does calculate a reasonably accurate increase in demand charges resulting from the proposed change to Billing Demand, albeit through flawed calculations. His conclusion regarding the impact of the Billing Demand change on the finances of example projects is also misleading. I have performed an analysis of Mr. Nolt's Exhibit BN-1, attached as Exhibit NJ-4R, and describe my findings below. The analysis incorporates the updated proposed rates provided in Mr. Gorman's testimony (Citizens Statement No. 1R at 5).

First, regarding the increase in demand charges, Mr. Nolt's testimony claims an increase of $4,788 annually ($7,908 - $3,120)[16], which equates to an average monthly increase of $399. This approximately matches my calculated average increase of $402/month, or $4,891 annually using the originally proposed rates. Using the updated proposed rates, this increase is reduced to $338/month, or $4,054 annually. Although his ultimate conclusion was reasonable, his method of calculating demand charges is inherently flawed. Mr. Nolt uses *average* demand only to determine annual charges, which is not an accurate method of calculating costs that are based on *peak* demand. Similarly, Mr. Nolt determines his generation rate by calculating individual PTC prices from January 2014 through February

[16] SP Statement No. 1 at 4.

2024 without weighting for the length of time each price was in effect or seasonal variation in SPV output.

Second, Mr. Nolt's concluding analysis of the project finances projects an annual loss of $6,082 ($29,050 – $22,968). He asserts that customer-generators "below 400 kW that are offsetting usage will be unable to adequately service debt payments as well due to the 153% increase in distribution costs.[17]" This ignores the fact that even if his calculated annual distribution increases of $4,788 were returned, he would still be operating at an annual loss of $1,294. I find it unlikely that a commercial solar developer would install a project that, at year-one rates, would result in a $68,000 loss over of the life of the project ($1,294 x 25 years plus 10% down payment). Either the example provided neglects to include expected revenues (or savings/credits), or the project is not financially viable regardless of the proposed tariff change.

Q. Does the Gross Generator Capacity of a solar array have to exceed an existing customer's peak demand in order to offset that customer's annual kWh usage?

A. Not necessarily, different customers have different load characteristics. The existing load in Mr. Nolt's exhibit has a 'load factor' (the ratio of the actual kWh consumed or generated against the total potential kWh consumed or generator over a specific period of time—one year, in this case) of approximately 50%. As load factor increases, more kWh consumption occurs for the same peak demand. Customer load factors can vary widely, as can the load factor of different generation sources.

For customer-generators planning to offset their annual usage, the relationship between the output capacity of their generation system and their existing peak load will depend on the

[17] SP Statement No. 1 at 5.

relative load factors of their chosen generation source and their existing load. Mr. Nolt's assertion that customer-generators must install generation with Gross Generator Capacity significantly exceeding existing peak demand is incorrect, it may be true for the generation source (solar) that he provides and the consumption (poultry barns in all cases referenced) he seeks to offset, but should not be assumed to be true for all potential customer-generators.

Q. Please explain the relevance of load factor for generation sources.

A. Solar generation has a relatively 'poor' load factor, meaning that the total kWh output of the generation system is low compared to the potential output if it were able to operate at maximum capacity at all times. This is an inherent characteristic of solar generation, as it can only generate during daylight hours, and even then only approaches its Gross Generator Capacity for a few hours each day. Other generation sources have different load factors, driven by the characteristics of the generator, availability of fuel (or environmental energy source), and the operating needs and preferences of the customer-generator. Reservoir hydropower, for example, could be expected to maintain a much higher load factor. The energy source is large and can be proactively managed, and the generator can run at all times of the day. Also, biomethane or landfill gas generators use animal or landfill waste, which can have higher load factors. Wind power is also eligible for net metering under the Commission's regulations.

Q. Mr. Nolt's Exhibit BN-1 includes two "options" for future projects. Please summarize the options suggested by Mr. Nolt.

A. Mr. Nolt includes the following "options":

Option 1: Reduce the tariff distribution rate by 55% to $2/kW for all net-metered systems (both grid supply and usage customers), to keep costs neutral for customers with/without solar and have everyone "pay their fair share";

Option 2: Change back the billed (sic) demand definition since 100% usage net-metered solar has very little electric demand impact. This option is preferred due to the fact that a customer that only has a demand of 200 kW normally will need a >400 kW Solar Array to offset 100% of their usage, and then their account will get kicked into time of use, which adds a lot of complexity to Net Metering, and are harder to educate customers and banks on. Language will need to be added to encompass systems that produce >200% of usage (grid supply) will need to pay $2/kW.

Q. Do you agree that any modifications made to accommodate Mr. Nolt's concerns should apply only to "future projects"?

A. No. The underlying reasons for the changes that we have proposed do not depend on whether the customer-generator's system was installed before our April 30, 2025 filing or after the April 30, 2025 filing. The Commission should not create a special class of customer-generators based on the filing date or based on the effective date of the tariff change.

Q. Please address Mr. Nolt's Option 1.

A. This option requires us to maintain a separate distribution rate for accounts with customer-generators and is not acceptable. We do not support creating a new distribution customer class and separate rate for the customer-generators. Additionally, the $2/kW rate was apparently chosen in order to neutralize the effect of the proposed billing demand change, without regard for actual cost-of-service principals.

Q. Please discuss Mr. Nolt's Option 2.

A. Option 2 essentially requires Citizens' to abandon our proposal for customer-generators that produce less than 200% of the host account's annual usage. It appears, however, that Mr. Nolt would allow us to implement it for customer-generators that exceed that threshold. We do not see a legal or cost of service basis to make this distinction in the application of the proposal.

Q. Is Citizens' willing to phase-in the proposal over multiple years to mitigate the immediate impact on the distribution costs for non-residential net-metered accounts?

A. Yes. We are willing to modify the tariff definition to indicate that 70% of Gross Generator Capacity will be considered in 2026 (Year 1), 85% of Gross Generator Capacity will be considered in 2027 (Year 2), and 100% of Gross Generator Capacity will be considered in 2028 (Year 3). The modified definition is as follows:

> (a) **Billing Demand:** Billing Demand shall reflect the Customer's use of the distribution system, which will be the greater of Gross Generator Rating (kW(AC)) as stated in the generator interconnection application or the maximum demand of the customer during any 15-minute period during the current month.
>
> *(i) For the purposes of determining the applicability of the GSSR-1 or GSSR-2, the Billing Demand definition shall apply effective January 30, 2026.*
>
> *(ii) For the purposes of calculating distribution charges under Rates GLP-1 and GLP-3, the following provisions shall apply:*
>
> *(i) For calendar year 2026, the Gross Generator Rating shall be reduced by 30% in calculating the Billing Demand.*
>
> *(ii) For calendar year 2027, the Gross Generator Rating shall be reduced by 15% in calculating the Billing Demand.*
>
> *(iii) For calendar year 2028 and beyond, there shall be no reduction to the Gross Generator Rating in calculating the Billing Demand.*

Q. Why is it important to specify the phase-in in the tariff language?

A. Specifying the phase-in in the tariff language will ensure all customer-generators, customers considering a project and project developers understand that the Billing Demand will change in the subsequent years.

Q. Both Mr. Nolt and Mr. Lucas assert that Citizens' has not demonstrated that it faces increased costs from having a customer-generator on its system. Do you have any comments?

A. First, Citizens' is not proposing to create a new distribution rate to reflect solely the distribution costs that are specific to non-residential customer-generators. Rather, we are apportioning a fair share of distribution-related costs to the net-metered accounts based on their use of the distribution system and company facilities. We are treating them like other customers by asking them to pay appropriate portions of distribution O&M costs, joint and common costs like the billing system, and the return on the Company's distribution system facilities. Without their contribution to those costs, more will be required to be paid by the other customers on the system.

Second, I disagree with the implication that a customer who installs on-site generation with capacity that exceeds the historic account generation demand is not changing its use of the distribution system. The customer is placing a new obligation on Citizens' and on the distribution system by exporting more energy than it previously imported, and then expecting the return of the "banked" excess supply on-demand.

Finally, the Company does not argue that generation, by nature, creates additional costs compared to consumption of a similar magnitude. Rather, we seek to treat all utilization of the distribution system equally, regardless of the direction in which power flows.

Q. Why is it important to make the change at this time?

A. First, we are following the Commission's decision in the UGI case currently pending before the Commission. The Commission adopted essentially the same proposal for the net metering crediting and annual cashout of UGI hourly default service customers. Although

the demand threshold is different, it is essentially the same and the precedent should be followed here, especially for administering the net metering billing credit.

Second, new technologies continue to be introduced that are changing the nature of the distribution system. There is an increasing expectation that the distribution utility will accommodate Distributed Energy Resources ("DERs"), electric vehicles and other advancements. In this environment, it is important to evaluate how distribution costs will be collected among ratepayers who adopt those technologies and ratepayers that do not adopt those technologies.

Third, it is especially important at this time to ensure that larger customer-generators over 400 kWAC are being credited and compensated under the GSSR-2 rate. Mr. Nolt's testimony discusses the historic difference between the GSSR-1 price to compare ("PTC") and the average LMP that is relied upon for the GSSR-2. Our GSSR-1 PTC is expected to increase further over the upcoming years due to the rising capacity prices in the PJM markets. Ensuring that the customer-generators with Billing Demands over 400 kW are accounted for as GSSR-2 accounts will ensure that any cashout is reflected in the reconciliation for the GSSR-2 class, rather than the GSSR-1 class. This will reduce costs paid for by the GSSR-1 class, which includes residential customers.

Q. Would a phase-in apply to the generation charges and net metering cash-out?

A. No. Given the impending wholesale generation cost changes that will be impacting the GSSR-1 PTC, it is important to implement the generation portion of the proposal without a phase-in. Generation supply costs are required by statute to be passed through directly to ratepayers. Phasing-in generation charges would intentionally introduce a discrepancy

between supply costs and recovery of those costs by the ratepayers incurring them and is not appropriate.

Q. Why does the Company propose to use the Gross Generator Capacity for the on-site generation as stated in the Interconnection Application for the Billing Demand determination rather than an alternative measure such as the maximum hourly exported demand in each month?

A. First, we used the Gross Generator Capacity because it was what the Commission approved for UGI (under a different term—"Supply Peak Load Impact"). Especially for the generation rate classification, we believed it was preferable to mirror the UGI structure to the extent warranted. Of course, Citizens' has a different demarcation for our hourly default generation service than UGI maintains (i.e., Citizens' uses 400 kWAC and UGI uses 100 kWAC).

Second, we want to use a common definition for "Billing Demand" for both generation and distribution services to minimize customer confusion associated with the changes. This also helps our internal administration of net metering.

Finally, as I will address in more detail below, the Gross Generator Capacity is the demand level that we must plan for our system to be able to accommodate. Thus, it is the most appropriate measure for this purpose.

Q. Could the Commission adopt a different method to calculate the Billing Demand for customer-generators?

A. Yes. There are other possibilities that could be used, such as the 15 minutes of maximum bi-directional demand during the billing cycle. As previously explained, we believe that following the UGI approach is appropriate and best reflective of how we must plan for the

customer-generator. In addition, our meters currently are not programmed to measure bi-directional demand; however, the meters could be reprogrammed to measure bi-directional demand or we could purchase meters with this capability. We have some concerns that using the bi-directional demand could result in an account moving between the GSSR-1 and GSSR-2 net-metering credit process on an annual basis. In addition to changing the billing credit for the customer-generator, it would shift the annual cashout costs between the GSSR-1 and GSSR-2 default service classes, which could result in rate volatility for each of the default service rates. Adopting the Gross Generator Capacity avoids this variation for the customer-generator and for the other default service customers who pay the net cashout.

If the Commission views the bi-directional demand as more appropriate, then the Company could use the bi-directional demand in lieu of Gross Generator Capacity. The phase-in would not be needed.

Q. Mr. Nolt and Mr. Lucas complain about the economic impact of the Company's proposal on certain solar projects. Is the economic viability of a customer-generator the appropriate yardstick against which to measure Citizens' proposed inclusion of the Gross Generator Capacity in the calculation of Billing Demand?

A. No. As the ALJs discussed in the UGI Recommended Decision, the economic impact on certain customer-generators is not the litmus test for assessing the correct default service rate classification. We believe that applies equally to the correct distribution cost evaluation. The Commission must balance the interests of all ratepayers, not just seek to maximize the business economics of a small subset of the users of the distribution system. This becomes even more critical when the generation owner is not a Citizens' ratepayer.

Q. Is generation a regulated business in Pennsylvania?

A. No. The generation of electricity is not a regulated business in Pennsylvania. As such, there is no guarantee of profits for a particular customer-generator.

Q. Does net-metered generation "[help] grid congestion?" (SP Statement No. 1 at 6)

A. Yes, to a limited extent. Net-metered generation, if it is producing during times of high demand, and if it is located with or near to sufficient load, can help to ease local congestion and/or reduce system demand.

Q. Does solar production typically coincide with peak demand hours?

A. Again, to a limited extent. The Company's response to SP-II-5 provides an analysis demonstrating that, on average, approximately 28% of rated solar output is available to the distribution system during PJM peak hours. Mr. Nolt's testimony cites a 0-10% reduction in peak demand[18], similarly demonstrating the limited ability of solar to reduce customer peaks. The coincidence between peak hours and solar production is also highly volatile and can be expected to vary from 0% to 81% availability, with no ability by the utility to dispatch the generation when it is needed most. Network System Peak Load ("NSPL") hours that determine our PJM transmission requirements are particularly unaffected by solar production, with 44% of NSPL hours occurring during times when less than 5% of rated solar capacity is available to the distribution system.

Q. Will net metering larger customer-generators under the GSSR-2 rate increase the incentive to maximize exports during peak hours?

A. Yes. Using the GSSR-2 hourly energy rate in the net metering credit mechanism encourages the customer-generator to export power to the distribution system during

[18] Statement No. 1, Page 5.

higher-priced hours. Although a solar generator may be relatively inelastic in producing power in response to hourly prices, many qualifying net-metered generation sources are able to respond directly to price signals. In addition, even the customer-generator with a solar array may be able to reduce the host load consumption to increase its exports during these hours. The GSSR-2 credit mechanism rewards any customer-generator, regardless of the energy source, for high coincidence between load and generation, and exports during high-demand hours. GSSR-2 customers' transmission and capacity costs are based on their individual contribution to the Company's peaks, so well-aligned load and/or exports during peak hours can reduce or even eliminate transmission and capacity costs for the coming energy year.

Q. Does net metering larger generators under the GSSR-1 rate provide similar incentives?

A. No. In fact, the GSSR-1 rate provides an economic disincentive for exporting during high-demand hours. Net exporting customer-generators are paid at the end of the energy-year at the PTC, which includes transmission and capacity costs determined by the Company's contribution to annual PJM peak hours. Exporting during peak hours reduces the Company's costs, thus reducing the value of export credits. Net-metered generation is non-dispatchable and, as Mr. Nolt states in his testimony, is able to "go offline immediately[19]," so a customer-generator could reduce or eliminate output during peak hours to maximize the value of future export credits. In short, rather than incentivizing customer-generators to export during peak hours for benefit of all ratepayers in the class, the GSSR-1 rate structure, coupled with net metering code requirements, provide a financial incentive for

[19] SP Statement No. 1 at 6.

customer-generators to deny exports during peak hours at the cost of non-exporting ratepayers.

Q. Is it true that the Company will no longer net kWh usage of customer-generators based on the tariff change? (SP Statement No. 1 at 6)

A. No, not at all. The Company has not proposed any change to the manner in which kWh usage is netted or banked on a monthly basis for distribution charges, and will only change credit for or netting of kWh generation charges to the extent that customer-generators with billing demands greater than 400 kW will be billed at the GSSR-2 rate (if they do not choose an Electric Generation Supplier) and credited or reimbursed in a manner appropriate with that rate structure.

Q. Is it appropriate to treat a 480 kW generator similarly to a 480 kW load? (SP Statement No. 1 at 6)

A. Yes. While every customer is unique, it is unrealistic to craft a rate structure tailored to each individual customer. Instead, the Company must structure its tariff to place customers in the rate class that best represents their characteristics. In the case of an account hosting a 480 kW generator, the customer-generator is *more* similar to loads of similar magnitude than to much smaller generators or loads. For non-residential GSSR-1 customers, the average demand is only 18 kW and 93% of GSSR-1 customers have demands of 50 kW or less, so while a 480 kW generator may be different than a 480 kW load, it differs far more from the majority of GSSR-1 customers.

Q. Mr. Nolt responded to a discovery response setting forth his views on why a 400 kW generator is similar to a 100 kW customer. Please respond to Mr. Nolt's arguments.

A. Attached as Exhibit__(NJ-5R) is Mr. Nolt's response to Citizens-SP-II-15. Mr. Nolt bases his claim of similarity that both customers are supplied by similar primary wire sizes, both are served by a transformer, and both are metered and receive bills. I will respond individually to each:

1) (1) High voltage tap into the 12kV system with similar primary wire size.

All of the Company's customers are supplied by primary wire and the Company, in similar fashion to many other utilities, uses only a limited number of primary wire sizes for new construction to increase efficiency and achieve cost savings through higher purchase volumes. The use of primary lines and the size of wire is largely irrelevant to the characteristics of individual customers.

2) (1) Transformer to install.

Again, nearly all of the Company's customers, excepting only a very small number of 'primary' customers are supplied by a transformer. Mr. Nolt's argument ignores the obvious difference in the size and corresponding cost of a transformer required to supply a 480 kW generation load versus a 100 kW demand customer. Assuming a 3-phase, 480V service for both, typical new 100 kW demand would be supplied by a 150 kVA pad-mounted transformer costing between $10,000 and $15,000, while a typical 480 kW demand would be supplied by a 500 kVA pad-mounted transformer costing $25,000 or more.

3) (1) Customer bill to produce, meter to read, etc (administrative side).

With the exception of unmetered street lights, all customers are entitled to a meter, bill, and other basic customer service functions, regardless of size. This function has little to do with a customer's utilization of the distribution system.

Mr. Nolt's response provides only characteristics common to nearly every customer served by Citizens' Electric. His similarity explanation proves nothing.

Q. What are the average demands for Citizens' non-residential customers on Rates GLP-1 and GLP-3?

A. The average demand for GLP customers is 26.2 kW, with over 93% of all GLP customers registering a maximum demand of less than 50 kW. Thus, most of our non-residential customers are not similar to the host sizes before the generation is installed and will be even less similar to the customer-generators after the generation is installed.

Q. Mr. Nolt claims that solar arrays are more flexible "with grid support functions, and the ability to go offline immediately." Please comment.

A. We explained to the Solar Projects in discovery that we do not have the ability to dispatch solar generation on our system or to communicate any need for "grid support". Mr. Nolt's attempt to create a distinction between a manufacturing plant and a solar array is factually incorrect on our distribution system and is a red herring. Additionally, "the ability to go offline immediately" is not a grid support function.

Q. Do you agree with Witness Nolt's assessment of LMP price volatility? (SP Statement No. 1 at 7)

A. No, Mr. Nolt is correct that LMP can vary significantly from one hour to the next. He ignores the fact that customer-generators are reimbursed for excess kWh produced only

once annually and netting credit only once monthly (under the Company's proposed treatment of GSSR-2 customer-generators), so hourly volatility can be addressed in Mr. Nolt's financial projections. An analysis of the past ten "energy years" (June 1 to May 31), comparing a LMP and PTC (weighted by solar availability), shows a maximum variation of 3.3 cents/kWh in LMP and 5.0 cents/kWh in PTC on an energy year basis.

Q. Please confirm that the GSSR-2, which is variable based on the LMP, is a retail rate.

A. Yes. The GSSR-2 is a retail rate charged to retail customers. The GSSR-2 contains a passthrough of several wholesale cost elements, including the LMP, the PJM capacity charge and the PPL transmission charge; however, it is a retail rate that has been approved by the Commission.

Q. Is it true that every customer-generator's demand will be based on the Gross Generator Capacity of their generation system under the proposed tariff change? (SP Statement No. 1 at 9)

A. No, Mr. Nolt incorrectly states that the Gross Generator Capacity of customer-generator's system "will always be greater than actual maximum demand[20]." This is not true for all existing non-residential customer-generators, and there is no requirement that it be the case for future installations. Customers size their system based on a variety of factors. Mr. Nolt's systems, to date, have had Gross Generator Capacities exceeding any existing on-site demand, but it is inappropriate to assume that all customer-generators size their systems using the same rationale as one developer.

[20] SP Statement No. 1 at 9.

Q. Please respond to Witness Nolt's question and answer on Page 9, Ln 10-12 of his testimony. (SP Statement No. 1 at 9)

A. In his testimony, Mr. Nolt responds in the affirmative to the question: "Is it true that demand charges are based on kW's or on Demand rather than kWh's which are based on energy flow?[21]"

It is unclear to me what exactly his question means, or how it is relevant to this discussion. Demand, for billing purposes, is a measurement, in kW, of the average real power flow through a meter over a 15-minute period. Usage is a measurement, in kWh, of the net accumulated energy consumed or exported through a meter during a billing period. Both are already used in non-residential utility billing. "Energy flow" is not an explicitly defined or universally recognized term within the utility industry. Of the two measurements discussed above, however, demand (kW) is the one that specifically measures the rate of 'flow' of energy, while usage (kWh) measures accumulated energy, regardless of the rate at which it 'flows.'

Q. Mr. Nolt comments on the notice that he received from Citizens' regarding the tariff changes. Please discuss.

A. Citizens' became aware of the Commission's decision in the UGI Default Service Proceeding in late February 2025. At that time, we began to analyze the implications for our service territory, including whether it would impact the rate case that we were then preparing. As required by the Commission's regulations, we provided the advanced confidential notice to the Commission on March 28, 2025, stating that we would be requesting rate relief in excess of $1 million. Our rate case was then filed on April 30,

[21] *Id.* at 9.

2025. We did not provide any party or customer with advanced briefings on the various proposals or content of the rate filing until it was submitted.

All customers were mailed our customer notice for the rate case on April 30, 2025. We also issued a press release to alert customers that we had submitted the filing. Shortly after the filing was made, we posted the filing on our website.

Mr. Nolt received personal contact from Citizens' on May 15th. Moreover, like Citizens', Mr. Nolt could have been aware of the Commission's decision in the UGI Default Service proceeding in late February.

Q. Did Mr. Nolt ask for the return of his deposits submitted on March 31 and April 28?

A. No.

Q. Did Mr. Nolt submit additional payments after he knew of the filing?

A. Yes. Despite knowing that the proposal had been submitted, he indicated in his testimony that he chose to go forward with a deposit in July 2025. He submitted the deposits despite the regulatory uncertainty that currently exists regarding the treatment of customer-generators. In an environment where rate designs, classifications and other rules can change, the Commission's actions on the UGI proposal placed all stakeholders on notice. His claims of reliance and "irreparable harm" should be rejected.

Q. Mr. Lucas indicates that the Company has provided "thin" support for its proposal and that it should be rejected on this basis. Do you have any comments?

A. Mr. Lucas misunderstands the rate case process. We provided Direct Testimony to explain the proposal. The Solar Projects had the opportunity to ask discovery questions regarding our testimony if they needed additional detail. During discovery, we responded to three sets of questions from the Solar Projects. They provided their Direct Testimony, to which

we will respond. Our attorneys will address during the briefing stage the "burden of proof" and what level is required to approve our proposals.

Q. Is the Company's proposed billing demand change based on "hypothetical, idealized" use of its distribution system? (SP Statement No. 2 at 3)

A. No, it is based on the realistic and likely potential output of a customer-generator. Mr. Lucas asserts throughout his testimony that customer-generators rarely, if ever, export the Gross Generator Capacity of their generation systems. It is true that solar arrays will output to their Gross Generator Capacity only infrequently, but this ignores the obligation of EDC's to design, build, and maintain a distribution system that can accommodate the Gross Generator Capacity at any time. His testimony assumes that all customer-generators are solar arrays, but the same rate structure must accommodate any qualifying net-metered energy source, many of which can run year-round at all times of the day. It is Mr. Lucas' arguments that are based on hypothetical—in that all customer-generators are solar arrays—and idealized—assuming that a customer will never produce the Gross Generator Capacity of their system—while the Company, instead, plans for realistic, inevitable utilization of the distribution system.

Q. Does the Company's proposal contradict or violate existing statutory or regulatory requirements? (SP Statement No. 2 at 4, 22)

A. No, 52 Pa. Code § 75.13(d) requires that the Company "…credit a customer-generator at the full retail kilowatt-hour rate, which shall include generation, transmission and distribution charges, for each kilowatt-hour produced…" The Company's proposal adheres to this regulation.

First, Mr. Lucas incorrectly asserts that 'bifurcating' distribution and generation for netting purposes is both novel and violates regulations. Distribution and generation are already 'bifurcated' because 1) under the existing rate structure, only portions of distribution costs are netted out through kWh net metering and 2) for shopping customers, the EDC does not provide any net credit for generation usage. Similarly, under the proposed change, the Company will continue to net those portions of distribution charges based on kilowatt-hour rates, and will do the same for generation charges, crediting the customer for any kilowatt-hour-based generation charges incurred at the kilowatt-hour rate value of exports.

Second, Mr. Lucas argues that the Company is shifting to a "net billing construct[22]" in violation of code. Pennsylvania code requires that EDCs *credit* customers at the full kilowatt-hour *rate*. Mr. Lucas asserts that because code states that the rate "shall include generation, transmission and distribution charges," it is a violation not to credit GSSR-2 customer-generators for transmission costs. Kilowatt-hour netting applies to charges that are billed on a kWh basis. For GSSR-2 customers, capacity and transmission are billed based on customers' individual contribution to the Company's peak loads, not on a kWh basis. This is similar to the crediting for distribution charges, where non-residential customers are credited only for the portion of their distribution charges that are billed at kWh rates and receive no credit towards their distribution customer or demand (kW) charges.

Finally, Mr. Lucas argues that converting generation usage to a dollar value violates code. This is incorrect, code does not explicitly require that the credit occur at the unit level, rather that customer-generators are *credited* for kilowatt-hours produces at the full

[22] SP Statement No. 2 at 23.

kilowatt-hour rate. The Company's proposal provides a credit for each kilowatt-hour produced at the rate for which any customer in the same class would pay for that same kilowatt-hour and applies against the customer-generator's kilowatt-hour based charges. Nowhere does this violate the plain language of Pennsylvania Code.

Q. Do the Commission's regulations contemplate that net metering may occur with a time-differentiated rate?

A. Yes. Although the particular portion of the Commission's regulations that Mr. Lucas cites was adopted before Citizens' had hourly default service and before the majority of the other EDCs in Pennsylvania had hourly default service, the regulations acknowledge that a utility can apply "load profiles" to determine hourly usage if it is appropriate to administer the net metering for the particular generation rate. Hourly metering is more precise than a load profile and is possible under our metering system. The GSSR-2 design using the hourly LMP is the most precise version of a time-differentiated retail energy rate.

Q. Is the pending appeal of UGI's Default Service Order a sufficient reason to reject Citizens' proposal?

A. In my opinion, it is not. I am advised that neither the Commission nor the Court has stayed the effectiveness of the decision. We urge the Commission to be consistent in its decisions on this issue by approving our proposal.

Q. Is the GSSR-2 rate inappropriate or unfair to net-metered customer-generators?

A. No. The GSSR-2 rate could be used today for net metering. Both Mr. Lucas and Mr. Nolt imply that the change to billing demand has created an unfair circumstance by placing customer-generators in the GSSR-2 generation rate class, but the Company's existing approved rate structures already make this possible. The likelihood that the proposed

change will place one or more of *Mr. Nolt's* projects in the GSSR-2 rate class is not relevant to the broader matter of determining a fair means of treating customer-generators with demand exceeding 400 kW, regardless of whether that demand is calculated using existing or proposed rate structures.

Q. Do you believe that the GSSR-2 rate is too complex for medium-sized businesses installing net-metered generation? (SP Statement No. 2 at 4)

A. No, the argument that the GSSR-2 rate is too 'complex' for medium-sized businesses is subjective and irrelevant. First, it is already possible under the existing rate structure for 'medium-sized' businesses to be placed in the GSSR-2 rate. Second, to suggest that a business successfully managing the financial and technical complexities of a $1 million or greater[23] generation system cannot understand the GSSR-2 generation rate is paradoxical.

Q. Has the Commission determined that medium-sized businesses can adapt to hourly pricing?

A. Yes. The Commission's default service regulations, policy statements and the *End State Order*, have expanded the hourly default service pricing to more and more customers, with the Commission's preferred threshold for the service being 100 kW. The Commission made clear in the recent UGI decision that the threshold for hourly pricing can apply to the net metering for customer-generators.

Q. Please discuss the level of sophistication for mid and large customer-generators that install generation.

A. The testimony here demonstrates the level of sophistication involved. Mr. Nolt indicates that the customer is installing a particular generation size to offset a large portion of the

[23] SP Statement No. 1 at 4.

annual consumption at the host site. In the process of doing this, the customer is undertaking a capital project to install generation that may cost over $1 million. They are entering into financing arrangements, if necessary. They are negotiating with the developer to construct (and possibly maintain) the project. They also must arrange for the developer or a third-party to market the alternative energy credits ("AECs") of the project. They may also be taking advantage of tax reduction strategies or governmental grants. All of those actions seem quite sophisticated.

Furthermore, for 5 of 6 projects in Citizens' territory, the actual solar array is owned by Mr. Nolt or third-party investors. The Commission is being asked to insulate those investors from the risk that tariff and net metering rules may change over time to reduce the subsidization they receive from Citizens' ratepayers.

Q. Does the Company propose to shift tariff break points to demand rather than "net usage of the grid?" (SP Statement No. 2 at 5)

A. It is unclear what Mr. Lucas means by this statement. The break points he discusses are based on billing demand under both existing and proposed rates, and forward and reverse billing demand are not netted against one another in either case.

Q. Is it unfair to bill a customer based on a demand level that was not reached during the billing period? (SP Statement No. 2 at 7)

A. No, this is already part of existing non-residential rate structures. The demand component of non-residential bills already includes a minimum of 50% of the highest demand during the preceding 11 billing periods, even if that exceeds actual demand measured during the current billing period. In fact, from June 2024 to May 2025, only 52% of all non-residential bills charged for the actual metered demand during the same period.

Q. Will the Company's proposed billing demand change "come with a mandatory change in the customer's rate schedule?[24]" (SP Statement No. 2 at 8)

A. No, Mr. Lucas' interpretation of the Company's tariff is incorrect. The 50 kW threshold for GLP-3 is the minimum demand required for a customer to be eligible for the rate, it does not require that the customer change to the rate. For accounts that are eligible for more than one rate class, namely GLP-1 vs. GLP-3, the Company routinely evaluates their usage and assists the customer in determining the most economical rate. Rather than mandating a change to a new distribution rate, the proposed change to billing demand may open up additional options for large customer-generators.

Q. Does the Company's proposed billing demand change break with historical rate conventions? (SP Statement No. 2 at 9)

A. No, because historic ratemaking conventions are not unchangeable. There were times in history when metering for many customers could not measure demand; however, as metering evolved, the distribution rate designs evolved. Similarly, when distribution rates were unbundled in the 1990s, some historic rate designs included multiple declining block distribution rates. Those designs have evolved. The practice of determining billing demand from forward (consumed) power only traces back to rate design methods that did not contemplate a distribution system in which the average consumer would produce power to be consumed elsewhere within the system. Rates have evolved over time based on the actual needs and use of the distribution system. Relative to historical billing practices, net metering is still a relatively new phenomenon, and the current trend of large customer-generators exporting substantially more power than they produce is even more recent. As

[24] SP Statement No. 2 at 8.

the impact of net-metered customer-generators on the distribution system, utility operations, and ratepayers has become discernable, the Company has evaluated it and developed a reasonable rate structure intended to recover the cost of serving customer-generators. While the specific definition of billing demand may incorporate new language to accommodate the changing nature and uses of the distribution system and, in that sense, "break from convention," the rationale behind the change is consistent with cost-of-service principles.

Q. Is it appropriate to bill customer-generators based on Gross Generator Capacity if their actual capacity might diminish over time? (SP Statement No. 2 at 9)

A. Yes, this is another example of the narrow line of reasoning presented by the Solar Projects. It is true that, using current technology, the output capacity of individual solar panels tends to degrade over time. However, this ignores the broad range of generation technology eligible for net metering, future improvements in solar panel longevity, and possibility that owners of large arrays have the ability to change panels that fail or sufficiently diminish in output without notifying the Company. Additionally, customer-generators are not obligated to report maintenance or upgrades 'behind' their inverters to the Company if the Gross Generator Capacity of the system does not change. A customer with declining output could install additional panels to augment losses without renewing their interconnection application. The company is obligated to build and maintain the system to accommodate the Gross Generator Capacity of the system, regardless of whether it ever produces to that level.

Q. Do you agree that the proposed billing demand definition ignores the on-site load of customer-generators? (SP Statement No. 2 at 9)

A. No, not at all. Metered, forward (consumed) demand remains part of the billing demand calculation. Mr. Lucas correctly notes in his testimony that "the apparent load for that a customer-generator places on the grid is a function of both BTM generation and its native load[25]." He then asserts that the Company's proposed changes "ignore this reality[26]." This is not true, as the customer-generator's native load and, particularly, its coincidence with generation output may have a substantial impact on monthly charges. Instead, it is the current rate structure that ignores the reality of the impact that generation has on the customer-generator's apparent load. The Company's proposed change seeks to rectify this and account for the influence of both generation and load on the distribution system.

Q. How do you respond to Witness Lucas' criticism of the Company's attachment provided with its response to SP-I-21? (SP Statement No. 2 at 10)

A. First, the Company always seeks to provide accurate and relevant information in support of its position and has provided an updated version of the workpaper as Exhibit NJ-6R. Mr. Lucas, in his testimony, devotes substantial effort to pointing out errors in an apparent effort to discredit the workpaper, but the conclusions he draws from his 'corrected' workpaper are not substantially different from the Company's original analysis. Additionally, several of his 'corrections' do not, in fact, correct errors, but instead adjust the analysis to circumstances that he believes are more realistic. He is entitled to his reanalysis, but these were hypothetical examples to begin with and his disagreement with the parameters used does not constitute an error on the Company's part.

[25] SP Statement No. 2 at 9.
[26] *Id.* at 9.

Q. Does the Company claim that customer-generators use "the entire distribution grid" to deliver exported power? (SP Statement No. 2 at 18)

A. No, of course not. No single customer uses the entire distribution system to deliver or receive power. Costs to build, operate, and maintain the distribution system are, to a certain extent, inherently socialized between ratepayers. Effective rate design, however, recovers costs from customers in a manner consistent with their contribution to the aggregated needs served by the Company's distribution system.

Q. Mr. Lucas asserts that the Company "takes title" to the energy that flows onto the Citizens' system. Does Citizens' take title to the energy produced by customer-generators? (SP Statement No. 2 at 18)

A. No. While I am not a lawyer, I have reviewed the net metering statute. It does not say that we are "purchasing" the output; rather, we have a duty to provide a credit to the customer-generator. Essentially, our distribution system acts as a virtual storage bank for the customer-generator, allowing them to over-produce energy and then use it at other times when their on-site generation does not produce enough to satisfy their consumption needs. Excess energy on an annual basis is similarly credited to the customer-generator at a regulated rate to compensate the generator for other customers' consumption of the energy. The statute creates a billing credit mechanism; it does not require us to purchase the power.

Q. Does the statute address title to other products?

A. Yes. It explicitly discusses the ownership ("title") of alternative energy credits related to the customer-generator.

Q. Please summarize Citizens' general responses to the Solar Parties' objections to the proposed change to billing demand.

A. The Solar Projects make numerous arguments opposing the change. I will address what are, based on my interpretation of their testimony, the overarching themes of these arguments.

1) <u>The change will negatively impact the finances of their projects and their future opportunities for development.</u>

I do not contest this argument; the Company's own testimony supports that the change will increase costs to *some* non-residential customer-generators and/or decrease the value of year-end credits they receive. However, these arguments are narrow in their scope. Their testimony seeks to project the negative financial impact on a very few customer-generators onto all non-residential net-metered customer-generators. This is unreasonable, as net metering represents a broad variety of renewable generation assets and customer needs, strategies, and financial circumstances. The Company's intent is to appropriately recover costs from all net-metered services. The fact that a certain few may incur substantial cost increases is not sufficient reason to reject the entire change.

2) <u>Placing a customer-generator on the GSSR-2 rate is unfair and violates PUC regulations.</u>

This argument fails, first and foremost, because rejecting the change to billing demand does not avoid the necessity of determining how to equitably treat GSSR-2 customer-generators. A customer-generator can already qualify as GSSR-2 under existing approved rates, rejecting the proposed change just so that it does not have to be

addressed now, and so that one existing and two proposed generation systems do not have to change class does not benefit the Company's ratepayers in general.

3) <u>There is no additional cost associated with supplying net-metered services, so increases in billing demand charges are unfair and "punitive[27]."</u>

The Company does not suggest that customer-generators incur *additional* costs on the distribution system beyond those incurred by consumed loads of similar magnitude, instead we present the argument that reverse (exported) demand incurs costs *similar* to that of forward (consumed) demand and should thus be charged similarly. Current rate structures provide no ability to recover costs incurred for accommodating net-metered exports when the generator size substantially exceeds the customer's consumed on-site demand, so nearly all of these costs are borne by non-generation ratepayers. The proposed change corrects this unbalance and assigns costs equitably to both generators and consumers. As to the purported 'punitive' nature of the change, accurately recovering costs is not punitive. Instead, customer-generators have unfairly benefited from a gap in historical rate structures that dramatically under-recover the costs they incur and shifts them onto others.

4) <u>The proposed change violates regulations.</u>

The argument that the change violates net metering regulations rests on a biased interpretation of current regulations, rather than an objective reading of the plain language of Pennsylvania Code. The Solar Projects misconstrue Pa. Code § 75 to require that credit be given in *units of kWh* rather than at the full or price-to-compare *rate*, and that transmission costs must be incorporated into a kilowatt-hour rate even

[27] SP Statement No. 2 at 16.

though a clear precedent, not disputed by the parties, already exists for crediting or compensating only those elements of charges that are already charged by the kilowatt-hour.

Q. Does this complete your Rebuttal Testimony?

A. Yes.

BEFORE
THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	**:**	
	:	
v.	**:**	**Docket No. R-2025-3054394**
	:	
Citizens' Electric Company of Lewisburg, PA	**:**	

EXHIBITS

OF

NATHAN JOHNSON

ON BEHALF OF

CITIZENS' ELECTRIC COMPANY OF LEWISBURG, PA

AUGUST 13, 2025

		ACTUALS					YTD	PROJECTED	
Account	**Description**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025 (YTD)**	**2025**	**2026**
593.1	Maint of OH Line – Expense Labor	$106,489.00	$114,612.00	$143,847.00	$133,851.00	$117,958.00	$74,928.10	$156,035.00	$159,253.00
593.2	Maint of OH Line – Expense Overhead	$106,316.00	$130,794.00	$159,594.00	$152,261.00	$155,040.00	$75,453.23	$178,455.00	$177,045.00
593.3	Maint of OH Line – Expense Transp	$26,591.00	$24,123.00	$35,073.00	$36,306.00	$30,857.00	$15,946.74	$44,338.00	$60,280.00
593.4	Maint of OH Line – Expense Material	$2,309.00	$5,778.00	$2,220.00	$37.00	-$122.00	$22,673.07	$892.00	$892.00
		$241,705.00	$275,307.00	$340,734.00	$322,455.00	$303,733.00	$189,001.14	$379,720.00	$397,470.00
593.5									
593.51	Vegetation Management Labor	$3,890.00	$6,503.00	$10,666.00	$7,497.00	$21,785.00	$3,761.74	$5,815.00	$5,815.00
593.52	Vegetation Management Overhead	$6,454.00	$7,141.00	$11,855.00	$7,527.00	$24,661.00	$4,373.58	$6,651.00	$6,465.00
593.53	Vegetation Management Transp	$372.00	$693.00	$2,427.00	$2,467.00	$1,087.00	$0.00	$1,738.00	$2,363.00
593.54	Vegetation Management Material	$159,782.00	$161,298.00	$105,438.00	$176,500.00	$166,761.00	$97,704.31	$195,000.00	$352,500.00
		$170,498.00	$175,635.00	$130,386.00	$193,991.00	$214,294.00	$105,839.63	$209,204.00	$367,143.00
593.6									
593.61	Pole Inspection Management Labor	$944.00	$1,011.00	$897.00	$846.00	$0.00	$322.71	$2,000.00	$2,000.00
593.62	Pole Inspection Management Overhead	$1,070.00	$1,235.00	$862.00	$907.00	$0.00	$350.25	$2,287.00	$2,223.00
593.63	Pole Inspection Management Transp	$22.00	$60.00	$38.00	$378.00	$0.00	$0.00	$0.00	$0.00
593.64	Pole Inspection Management Material	$35,225.00	$28,664.00	$26,973.00	$44,949.00	$40,534.66	$18,978.00	$74,000.00	$58,000.00
		$37,261.00	$30,970.00	$28,770.00	$47,080.00	$40,534.66	$19,650.96	$78,287.00	$62,223.00
	Total	$449,464.00	$481,912.00	$499,890.00	$563,526.00	$558,561.66	$314,491.73	$667,211.00	$826,836.00
	Non-Labor	$338,141.00	$359,786.00	$344,480.00	$421,332.00	$418,818.66	$235,479.18	$503,361.00	$659,768.00

RESPONSES OF
KELLY ROAD SOLAR, LLC, LANCASTER AVENUE SOLAR, LLC,
AND TWILIGHT RENEWABLES, LLC
TO INTERROGATORIES AND REQUESTS
FOR PRODUCTION OF DOCUMENTS
TO CITIZENS' ELECTRIC COMPANY OF LEWISBURG, PA, SET II

DOCKET NO. R-2025-3054394

Citizens'-SP-II-1

Please reference Statement No. 1, page 1. For each rooftop solar project listed at lines 16-19, please provide the following information:

A. Date that the project became operational or is expected to become operational.
B. Expected annual output of the solar project in MWh.
C. The customer's annual and monthly consumption of electricity in the 3 years immediately prior to the installation of the solar project.
D. The customer's peak demand for electricity by month in the 3 years immediately prior to the installation of the solar project.
E. Explain how the installed size of the solar array was finalized, including whether it was based on a desire to offset a percentage of the customer's annual usage, and, if so, the desired percentage that will be offset.
F. Does the customer receive revenue for the Alternative Energy Credits ("AECs") associated with the project?
G. If Mr. Nolt is aware, did the customer receive any tax credits and/or government grants associated with the project?
H. Does Twilight Renewables or Mr. Nolt own any of the equipment at the project? Please specify which equipment.
I. Does Twilight Renewables, Mr. Nolt or any company owned by Mr. Nolt install the solar equipment for the customer? If subcontractors are used, please explain the role of the subcontractors.
J. Does Twilight Renewables, Mr. Nolt or any company owned by Mr. Nolt receive compensation from the customer to maintain or operate the equipment after it is installed? Please explain how this compensation is determined.
K. Provide written, dated documentation (if any exists) confirming that Mr. Nolt is authorized to advocate on behalf of the customer in this proceeding.

RESPONSES OF
KELLY ROAD SOLAR, LLC, LANCASTER AVENUE SOLAR, LLC,
AND TWILIGHT RENEWABLES, LLC
TO INTERROGATORIES AND REQUESTS
FOR PRODUCTION OF DOCUMENTS
TO CITIZENS' ELECTRIC COMPANY OF LEWISBURG, PA, SET II

DOCKET NO. R-2025-3054394

RESPONSE:

A. Luke Hoover Project: 10/29/2024
Lancaster Avenue Solar LLC: 12/2/2024
TKK Solar LLC: 7/18/2025
IMP Solar LLC: 9/12/2025
Fairfield Road Solar LLC: 12/31/2025
Kelly Road Solar LLC: 4/30/2025

B. Luke Hoover: 285 MWh
Lancaster Avenue Solar LLC: 688MWh
TKK Solar LLC: 683 MWh
IMP Solar LLC: 654 MWh
Fairfield Road Solar LLC: 835 MWh
Kelly Road Solar LLC: 933 MWh

C. All projects with the exception of Luke Hoover are new services without historical usage/peak demand, and the only load on these services is solar equipment related. The Luke Hoover Solar project located at 7146 Furnace Road, Mifflinburg PA was constructed simultaneously with (3) new poultry barns and are electrically connected. The barns have not reached a full year in production yet. It is estimated that the barns will use 120MWh annually. Luke Hoover also has a farm less than 2 miles away at 7220 Old Turnpike Road, Mifflinburg PA that is virtually net metered and has an annual usage of 80MWh historically.

D. See answer above.

E. Luke Hoover was sized at 140% of usage to account for future farm usage growth over the next 20 years. All other systems were sized based off available roof space.

F. Yes, Current spot market value is at 2.6 Cents/kWh or $26/MWh. This is variable, and the future value is expected to decrease due to the compliance standards (which help drive demand) having remained unchanged since 2021, and because the supply of credits increases annually. Credit spot market prices have dropped from $36/MWh to $26/MWh in the past year alone.

RESPONSES OF
KELLY ROAD SOLAR, LLC, LANCASTER AVENUE SOLAR, LLC,
AND TWILIGHT RENEWABLES, LLC
TO INTERROGATORIES AND REQUESTS
FOR PRODUCTION OF DOCUMENTS
TO CITIZENS' ELECTRIC COMPANY OF LEWISBURG, PA, SET II

DOCKET NO. R-2025-3054394

G. No grants were received for any of these projects. For projects already placed in service (Luke Hoover, and Lancaster Avenue Solar LLC), tax credits were minted but are unable to utilize them themselves in the near term due to their specific tax situation.

H. Please specify which equipment. Luke Hoover, Lancaster Ave Solar, TKK Solar, and IMP solar are all 100% owned by parties outside of Twilight Renewables/Mr. Nolt. Brett Nolt is the current owner of Fairfield Road Solar LLC, and Kelly Road Solar LLC.

I. If subcontractors are used, please explain the role of the subcontractors. Twilight Renewables was the EPC Contractor for all of the projects. Supplemental subcontractors were used for excavation, and some electrical labor, with oversight by Twilight Personnel.

J. Twilight offers a 10-year workmanship warranty on the installation. Customers in the first 10 years do not typically sign O&M agreements for the system until after the warranty period expires. That being said, it is encouraged to wash panels every 1-2 years to maintain production levels (a service not performed by Twilight), and to set aside sufficient funds to replace inverters between years 10 and 20 (a $40-$50k expense overall)

K. At this point the agreement was not reduced to writing but is now in process.

Provided By: Brett Nolt

Dated: August 4, 2025

RESPONSES OF
KELLY ROAD SOLAR, LLC, LANCASTER AVENUE SOLAR, LLC,
AND TWILIGHT RENEWABLES, LLC
TO INTERROGATORIES AND REQUESTS
FOR PRODUCTION OF DOCUMENTS
TO CITIZENS' ELECTRIC COMPANY OF LEWISBURG, PA, SET II

DOCKET NO. R-2025-3054394

Citizens'-SP-II-8

Please reference Statement No. 1, page 7, line 4.

A. Which of the six projects listed earlier in Mr. Nolt's testimony is referenced in this response?
B. Please explain in detail the contractual relationship with the customer at the project site(s) that results in Mr. Nolt or his company holding the debt for the project, including, but not limited to, what compensation or benefits the customer is receiving for hosting the solar array.
C. Could the debt reference in this statement be refinanced?
D. What role does the revenue from Alternative Energy Credits ("AECs") serve in the financial profile and Mr. Nolt's ability to service the debt?

RESPONSE:

A. Kelly Road Solar LLC.

B. All projects with the exception of the Luke Hoover Project, are roof leases. There is a third-party investor that owns the solar array, and the site host receives compensation (over 99% upfront) for rooftop access for the life of the solar array. All electrical infrastructure is separate from the host.

C. If the electric rate goes from 8.565 cents per kWh to 3.2 cents per kWh, no bank would be able to underwrite this, regardless of term length due to the project losing money annually.

D. Banking underwriters typically do not account for AEC's in the Debt service coverage ratio calculations due to their high variability.

Provided By: Brett Nolt

Dated: August 4, 2025

50kW Load w/ 50kW Gen

Period	Metered Demand (kW)	Rated Output (kW)	Existing Demand Def Present Rates: Billed Demand (kW)	Demand Charge	Customer Charge	Existing Demand Def Proposed Rates: Billed Demand (kW)	Demand Charge	Customer Charge	Propsed Demand Def Proposed Rates: Billed Demand (kW)	Demand Charge	Customer Charge
202506	43.23	50.00	43.23	$ 161.67	$ 16.00	43.23	$ 163.83	$ 21.00	50.00	$ 189.50	$ 21.00
202505	39.46	50.00	39.46	$ 147.59	$ 16.00	39.46	$ 149.56	$ 21.00	50.00	$ 189.50	$ 21.00
202504	42.92	50.00	42.92	$ 160.52	$ 16.00	42.92	$ 162.67	$ 21.00	50.00	$ 189.50	$ 21.00
202503	47.90	50.00	47.90	$ 179.15	$ 16.00	47.90	$ 181.55	$ 21.00	50.00	$ 189.50	$ 21.00
202502	50.00	50.00	50.00	$ 187.00	$ 16.00	50.00	$ 189.50	$ 21.00	50.00	$ 189.50	$ 21.00
202501	47.96	50.00	47.96	$ 179.37	$ 16.00	47.96	$ 181.77	$ 21.00	50.00	$ 189.50	$ 21.00
202412	43.15	50.00	43.15	$ 161.36	$ 16.00	43.15	$ 163.52	$ 21.00	50.00	$ 189.50	$ 21.00
202411	40.53	50.00	40.53	$ 151.56	$ 16.00	40.53	$ 153.59	$ 21.00	50.00	$ 189.50	$ 21.00
202410	37.89	50.00	37.89	$ 141.72	$ 16.00	37.89	$ 143.61	$ 21.00	50.00	$ 189.50	$ 21.00
202409	36.48	50.00	36.48	$ 136.44	$ 16.00	36.48	$ 138.27	$ 21.00	50.00	$ 189.50	$ 21.00
202408	37.98	50.00	37.98	$ 142.04	$ 16.00	37.98	$ 143.94	$ 21.00	50.00	$ 189.50	$ 21.00
202407	44.82	50.00	44.82	$ 167.63	$ 16.00	44.82	$ 169.87	$ 21.00	50.00	$ 189.50	$ 21.00
202406	39.90	50.00									
202405	40.70	50.00		$ 1,916	$ 192		$ 1,942	$ 252		$ 2,274	$ 252
202404	40.04	50.00			**$ 2,108**			**$ 2,194**			**$ 2,526**
202403	42.57	50.00									
202402	48.00	50.00		*$ 160*	*$ 16*		*$ 162*	*$ 21*		*$ 190*	*$ 21*
202401	45.43	50.00			*$ 176*			*$ 183*			*$ 211*
202312	69.14	50.00									
202311	41.15	50.00								Monthly Diff:	$ 28
202310	42.97	50.00								Annual Diff:	$ 332
202309	42.06	50.00									
202308	54.65	50.00									

Rate:	GLP-1	GLP-1	GLP-1
Effective:	Present	Proposed	Proposed
Min Demand:	5.00	5.00	5.00
Cust Charge:	$ 16.00	$ 21.00	$ 21.00
Demand Charge:	$ 3.74	$ 3.79	$ 3.79

50kW Load w/ 150kW Gen

Period	Metered Demand (kW)	Rated Output (kW)	Existing Demand Def Present Rates: Billed Demand (kW)	Demand Charge	Customer Charge	Existing Demand Def Proposed Rates: Billed Demand (kW)	Demand Charge	Customer Charge	Propsed Demand Def Proposed Rates: Billed Demand (kW)	Demand Charge	Customer Charge
202506	43.23	150.00	43.23	$ 161.67	$ 16.00	43.23	$ 163.83	$ 21.00	150.00	$ 568.50	$ 21.00
202505	39.46	150.00	39.46	$ 147.59	$ 16.00	39.46	$ 149.56	$ 21.00	150.00	$ 568.50	$ 21.00
202504	42.92	150.00	42.92	$ 160.52	$ 16.00	42.92	$ 162.67	$ 21.00	150.00	$ 568.50	$ 21.00
202503	47.90	150.00	47.90	$ 179.15	$ 16.00	47.90	$ 181.55	$ 21.00	150.00	$ 568.50	$ 21.00
202502	50.00	150.00	50.00	$ 187.00	$ 16.00	50.00	$ 189.50	$ 21.00	150.00	$ 568.50	$ 21.00
202501	47.96	150.00	47.96	$ 179.37	$ 16.00	47.96	$ 181.77	$ 21.00	150.00	$ 568.50	$ 21.00
202412	43.15	150.00	43.15	$ 161.36	$ 16.00	43.15	$ 163.52	$ 21.00	150.00	$ 568.50	$ 21.00
202411	40.53	150.00	40.53	$ 151.56	$ 16.00	40.53	$ 153.59	$ 21.00	150.00	$ 568.50	$ 21.00
202410	37.89	150.00	37.89	$ 141.72	$ 16.00	37.89	$ 143.61	$ 21.00	150.00	$ 568.50	$ 21.00
202409	36.48	150.00	36.48	$ 136.44	$ 16.00	36.48	$ 138.27	$ 21.00	150.00	$ 568.50	$ 21.00
202408	37.98	150.00	37.98	$ 142.04	$ 16.00	37.98	$ 143.94	$ 21.00	150.00	$ 568.50	$ 21.00
202407	44.82	150.00	44.82	$ 167.63	$ 16.00	44.82	$ 169.87	$ 21.00	150.00	$ 568.50	$ 21.00
202406	39.90	150.00									
202405	40.70	150.00		$ 1,916	$ 192		$ 1,942	$ 252		$ 6,822	$ 252
202404	40.04	150.00			**$ 2,108**			**$ 2,194**			**$ 7,074**
202403	42.57	150.00									
202402	48.00	150.00		*$ 160*	*$ 16*		*$ 162*	*$ 21*		*$ 569*	*$ 21*
202401	45.43	150.00			*$ 176*			*$ 183*			*$ 590*
202312	69.14	150.00									
202311	41.15	150.00								Monthly Diff:	$ 407
202310	42.97	150.00								Annual Diff:	$ 4,880
202309	42.06	150.00									
202308	54.65	150.00									

Rate:	GLP-1	GLP-1	GLP-1
Effective:	Present	Proposed	Proposed
Min Demand:	5.00	5.00	5.00
Cust Charge:	$ 16.00	$ 21.00	$ 21.00
Demand Charge:	$ 3.74	$ 3.79	$ 3.79

150kW Load w/ 75kW Gen

Period	Metered Demand (kW)	Rated Output (kW)	Existing Demand Def Present Rates: Billed Demand (kW)	Demand Charge	Customer Charge	Existing Demand Def Proposed Rates: Billed Demand (kW)	Demand Charge	Customer Charge	Propsed Demand Def Proposed Rates: Billed Demand (kW)	Demand Charge	Customer Charge
202506	85.24	75.00	85.24	$ 457.75	$ 55.00	85.24	$ 571.97	$ 100.00	85.24	$ 571.97	$ 100.00
202505	119.89	75.00	119.89	$ 643.82	$ 55.00	119.89	$ 804.48	$ 100.00	119.89	$ 804.48	$ 100.00
202504	114.28	75.00	114.28	$ 613.68	$ 55.00	114.28	$ 766.81	$ 100.00	114.28	$ 766.81	$ 100.00
202503	133.29	75.00	133.29	$ 715.77	$ 55.00	133.29	$ 894.38	$ 100.00	133.29	$ 894.38	$ 100.00
202502	150.00	75.00	150.00	$ 805.50	$ 55.00	150.00	$ 1,006.50	$ 100.00	150.00	$ 1,006.50	$ 100.00
202501	138.51	75.00	138.51	$ 743.82	$ 55.00	138.51	$ 929.43	$ 100.00	138.51	$ 929.43	$ 100.00
202412	132.78	75.00	132.78	$ 713.03	$ 55.00	132.78	$ 890.95	$ 100.00	132.78	$ 890.95	$ 100.00
202411	107.12	75.00	131.95	$ 708.58	$ 55.00	131.95	$ 885.40	$ 100.00	131.95	$ 885.40	$ 100.00
202410	88.22	75.00	131.95	$ 708.58	$ 55.00	131.95	$ 885.40	$ 100.00	131.95	$ 885.40	$ 100.00
202409	90.81	75.00	131.95	$ 708.58	$ 55.00	131.95	$ 885.40	$ 100.00	131.95	$ 885.40	$ 100.00
202408	75.56	75.00	131.95	$ 708.58	$ 55.00	131.95	$ 885.40	$ 100.00	131.95	$ 885.40	$ 100.00
202407	83.00	75.00	131.95	$ 708.58	$ 55.00	131.95	$ 885.40	$ 100.00	131.95	$ 885.40	$ 100.00
202406	77.79	75.00									
202405	122.93	75.00		$ 8,236	$ 660		$ 10,292	$ 1,200		$ 10,292	$ 1,200
202404	147.86	75.00			**$ 8,896**			**$ 11,492**			**$ 11,492**
202403	161.54	75.00									
202402	162.40	75.00		*$ 686*	*$ 55*		*$ 858*	*$ 100*		*$ 858*	*$ 100*
202401	168.40	75.00			*$ 741*			*$ 958*			*$ 958*
202312	263.90	75.00									
202311	109.12	75.00								Monthly Diff:	$ -
202310	95.00	75.00								Annual Diff:	$ -
202309	80.16	75.00									
202308	84.66	75.00									

Rate:	GLP-3	GLP-3	GLP-3
Effective:	Present	Proposed	Proposed
Min Demand:	50.00	50.00	50.00
Cust Charge:	55.00	100.00	$ 100.00
Demand Charge:	5.37	6.71	$ 6.71

400kW Load w/ 500kW Gen

Period	Metered Demand (kW)	Rated Output (kW)	Existing Demand Def Present Rates: Billed Demand (kW)	Existing Demand Def Present Rates: Demand Charge	Existing Demand Def Present Rates: Customer Charge	Existing Demand Def Proposed Rates: Billed Demand (kW)	Existing Demand Def Proposed Rates: Demand Charge	Existing Demand Def Proposed Rates: Customer Charge	Propsed Demand Def Proposed Rates: Billed Demand (kW)	Propsed Demand Def Proposed Rates: Demand Charge	Propsed Demand Def Proposed Rates: Customer Charge
202506	400.00	500.00	400.00	$ 1,496.00	$ 16.00	400.00	$ 1,516.00	$ 21.00	500.00	$ 1,895.00	$ 21.00
202505	319.31	500.00	319.31	$ 1,194.23	$ 16.00	319.31	$ 1,210.19	$ 21.00	500.00	$ 1,895.00	$ 21.00
202504	284.05	500.00	284.05	$ 1,062.35	$ 16.00	284.05	$ 1,076.55	$ 21.00	500.00	$ 1,895.00	$ 21.00
202503	241.34	500.00	241.34	$ 902.61	$ 16.00	241.34	$ 914.68	$ 21.00	500.00	$ 1,895.00	$ 21.00
202502	248.04	500.00	248.04	$ 927.67	$ 16.00	248.04	$ 940.07	$ 21.00	500.00	$ 1,895.00	$ 21.00
202501	240.17	500.00	240.17	$ 898.25	$ 16.00	240.17	$ 910.26	$ 21.00	500.00	$ 1,895.00	$ 21.00
202412	301.31	500.00	301.31	$ 1,126.91	$ 16.00	301.31	$ 1,141.97	$ 21.00	500.00	$ 1,895.00	$ 21.00
202411	284.86	500.00	284.86	$ 1,065.37	$ 16.00	284.86	$ 1,079.61	$ 21.00	500.00	$ 1,895.00	$ 21.00
202410	313.48	500.00	313.48	$ 1,172.43	$ 16.00	313.48	$ 1,188.10	$ 21.00	500.00	$ 1,895.00	$ 21.00
202409	361.11	500.00	361.11	$ 1,350.54	$ 16.00	361.11	$ 1,368.60	$ 21.00	500.00	$ 1,895.00	$ 21.00
202408	377.86	500.00	377.86	$ 1,413.21	$ 16.00	377.86	$ 1,432.11	$ 21.00	500.00	$ 1,895.00	$ 21.00
202407	370.85	500.00	370.85	$ 1,386.98	$ 16.00	370.85	$ 1,405.53	$ 21.00	500.00	$ 1,895.00	$ 21.00
202406	327.43	500.00									
202405	312.01	500.00		$ 13,997	$ 192		$ 14,184	$ 252		$ 22,740	$ 252
202404	271.89	500.00			**$ 14,189**			**$ 14,436**			**$ 22,992**
202403	245.43	500.00									
202402	255.85	500.00		*$ 1,166*	*$ 16*		*$ 1,182*	*$ 21*		*$ 1,895*	*$ 21*
202401	327.12	500.00			*$ 1,182*			*$ 1,203*			*$ 1,916*
202312	264.98	500.00									
202311	317.05	500.00								Monthly Diff:	$ 713
202310	377.56	500.00								Annual Diff:	$ 8,556
202309	353.24	500.00									
202308	383.74	500.00									

Rate:	GLP-1	GLP-1	GLP-1
Effective:	Present	Proposed	Proposed
Min Demand:	5.00	5.00	5.00
Cust Charge:	16.00	21.00	$ 21.00
Demand Charge:	3.74	3.79	$ 3.79

5kW Load w/ 480kW Gen

Period	Metered Demand (kW)	Rated Output (kW)	Existing Demand Def Present Rates: Billed Demand (kW)	Demand Charge	Customer Charge	Existing Demand Def Proposed Rates: Billed Demand (kW)	Demand Charge	Customer Charge	Propsed Demand Def Proposed Rates: Billed Demand (kW)	Demand Charge	Customer Charge
202506	5.00	480.00	5.00	$ 18.70	$ 16.00	5.00	$ 18.95	$ 21.00	480.00	$ 1,819.20	$ 21.00
202505	5.00	480.00	5.00	$ 18.70	$ 16.00	5.00	$ 18.95	$ 21.00	480.00	$ 1,819.20	$ 21.00
202504	5.00	480.00	5.00	$ 18.70	$ 16.00	5.00	$ 18.95	$ 21.00	480.00	$ 1,819.20	$ 21.00
202503	5.00	480.00	5.00	$ 18.70	$ 16.00	5.00	$ 18.95	$ 21.00	480.00	$ 1,819.20	$ 21.00
202502	5.00	480.00	5.00	$ 18.70	$ 16.00	5.00	$ 18.95	$ 21.00	480.00	$ 1,819.20	$ 21.00
202501	5.00	480.00	5.00	$ 18.70	$ 16.00	5.00	$ 18.95	$ 21.00	480.00	$ 1,819.20	$ 21.00
202412	5.00	480.00	5.00	$ 18.70	$ 16.00	5.00	$ 18.95	$ 21.00	480.00	$ 1,819.20	$ 21.00
202411	5.00	480.00	5.00	$ 18.70	$ 16.00	5.00	$ 18.95	$ 21.00	480.00	$ 1,819.20	$ 21.00
202410	5.00	480.00	5.00	$ 18.70	$ 16.00	5.00	$ 18.95	$ 21.00	480.00	$ 1,819.20	$ 21.00
202409	5.00	480.00	5.00	$ 18.70	$ 16.00	5.00	$ 18.95	$ 21.00	480.00	$ 1,819.20	$ 21.00
202408	5.00	480.00	5.00	$ 18.70	$ 16.00	5.00	$ 18.95	$ 21.00	480.00	$ 1,819.20	$ 21.00
202407	5.00	480.00	5.00	$ 18.70	$ 16.00	5.00	$ 18.95	$ 21.00	480.00	$ 1,819.20	$ 21.00
202406	5.00	480.00									
202405	5.00	480.00		$ 224	$ 192		$ 227	$ 252		$ 21,830	$ 252
202404	5.00	480.00			**$ 416**			**$ 479**			**$ 22,082**
202403	5.00	480.00									
202402	5.00	480.00		*$ 19*	*$ 16*		*$ 19*	*$ 21*		*$ 1,819*	*$ 21*
202401	5.00	480.00			*$ 35*			*$ 40*			*$ 1,840*
202312	5.00	480.00									
202311	5.00	480.00								Monthly Diff:	$ 1,800
202310	5.00	480.00								Annual Diff:	$ 21,603
202309	5.00	480.00									
202308	5.00	480.00									

Rate:	GLP-1	GLP-1	GLP-1
Effective:	Present	Proposed	Proposed
Min Demand:	5.00	5.00	5.00
Cust Charge:	$ 16.00	$ 21.00	$ 21.00
Demand Charge:	$ 3.74	$ 3.79	$ 3.79

5kW Load w/ 1000kW Gen

Period	Metered Demand (kW)	Rated Output (kW)	Existing Demand Def Present Rates: Billed Demand (kW)	Demand Charge	Customer Charge	Existing Demand Def Proposed Rates: Billed Demand (kW)	Demand Charge	Customer Charge	Propsed Demand Def Proposed Rates: Billed Demand (kW)	Demand Charge	Customer Charge
202506	5.00	1,000.00	5.00	$ 18.70	$ 16.00	5.00	$ 18.95	$ 21.00	1,000.00	$ 3,790.00	$ 21.00
202505	5.00	1,000.00	5.00	$ 18.70	$ 16.00	5.00	$ 18.95	$ 21.00	1,000.00	$ 3,790.00	$ 21.00
202504	5.00	1,000.00	5.00	$ 18.70	$ 16.00	5.00	$ 18.95	$ 21.00	1,000.00	$ 3,790.00	$ 21.00
202503	5.00	1,000.00	5.00	$ 18.70	$ 16.00	5.00	$ 18.95	$ 21.00	1,000.00	$ 3,790.00	$ 21.00
202502	5.00	1,000.00	5.00	$ 18.70	$ 16.00	5.00	$ 18.95	$ 21.00	1,000.00	$ 3,790.00	$ 21.00
202501	5.00	1,000.00	5.00	$ 18.70	$ 16.00	5.00	$ 18.95	$ 21.00	1,000.00	$ 3,790.00	$ 21.00
202412	5.00	1,000.00	5.00	$ 18.70	$ 16.00	5.00	$ 18.95	$ 21.00	1,000.00	$ 3,790.00	$ 21.00
202411	5.00	1,000.00	5.00	$ 18.70	$ 16.00	5.00	$ 18.95	$ 21.00	1,000.00	$ 3,790.00	$ 21.00
202410	5.00	1,000.00	5.00	$ 18.70	$ 16.00	5.00	$ 18.95	$ 21.00	1,000.00	$ 3,790.00	$ 21.00
202409	5.00	1,000.00	5.00	$ 18.70	$ 16.00	5.00	$ 18.95	$ 21.00	1,000.00	$ 3,790.00	$ 21.00
202408	5.00	1,000.00	5.00	$ 18.70	$ 16.00	5.00	$ 18.95	$ 21.00	1,000.00	$ 3,790.00	$ 21.00
202407	5.00	1,000.00	5.00	$ 18.70	$ 16.00	5.00	$ 18.95	$ 21.00	1,000.00	$ 3,790.00	$ 21.00
202406	5.00	1,000.00									
202405	5.00	1,000.00		$ 224	$ 192		$ 227	$ 252		$ 45,480	$ 252
202404	5.00	1,000.00			**$ 416**			**$ 479**			**$ 45,732**
202403	5.00	1,000.00									
202402	5.00	1,000.00		*$ 19*	*$ 16*		*$ 19*	*$ 21*		*$ 3,790*	*$ 21*
202401	5.00	1,000.00			*$ 35*			*$ 40*			*$ 3,811*
202312	5.00	1,000.00									
202311	5.00	1,000.00								Monthly Diff:	$ 3,771
202310	5.00	1,000.00								Annual Diff:	$ 45,253
202309	5.00	1,000.00									
202308	5.00	1,000.00									

	Existing Demand Def Present Rates	Existing Demand Def Proposed Rates	Propsed Demand Def Proposed Rates
Rate:	GLP-1	GLP-1	GLP-1
Effective:	Present	Proposed	Proposed
Min Demand:	5.00	5.00	5.00
Cust Charge:	$ 16.00	$ 21.00	$ 21.00
Demand Charge:	$ 3.74	$ 3.79	$ 3.79

	No Solar			Existing			Proposed			BD Change Impact			SP OPTION 1		
Consumption Period:	6/19 - 5/20	6/20 - 5/21	*Avg 6/19-3/22*	6/19 - 5/20	6/20 - 5/21	*Avg 6/19-3/22*	6/19 - 5/20	6/20 - 5/21	*Avg 6/19-3/22*	6/19 - 5/20	6/20 - 5/21	*Avg 6/19-3/22*	6/19 - 5/20	6/20 - 5/21	*Avg 6/19-3/22*
Total Cust:	$ 252.00	$ 252.00	*$ 21.00*	$ 252.00	$ 252.00	*$ 21.00*	$ 252.00	$ 252.00	*$ 21.00*	$ -	$ -	*$ -*	$ 252.00	$ 252.00	
Total kWh:	$ 2,714.25	$ 2,521.98	*$ 218.18*	$ 401.40	$ 295.21	*$ 29.03*	$ 401.40	$ 295.21	*$ 29.03*	$ -	$ -	*$ -*	$ 401.40	$ 295.21	*$ 29.03*
Total Demand:	$ 2,806.50	$ 2,911.67	*$ 238.26*	$ 2,525.85	$ 2,620.50	*$ 214.43*	$ 6,627.07	$ 6,627.07	*$ 552.26*	$ 4,101.23	$ 4,006.57	*$ 337.82*	$ 3,497.14	$ 3,497.14	*$ 291.43*
Total Distribution:	$ 5,772.75	$ 5,685.65	*$ 477.43*	$ 3,179.25	$ 3,167.71	*$ 264.46*	$ 7,280.47	$ 7,174.28	*$ 602.28*	$ 4,101.23	$ 4,006.57	*$ 337.82*	$ 4,150.54	$ 4,044.35	*$ 341.45*
Generation:	$ 31,756.24	$ 29,506.70	*$ 2,552.62*	$ 4,696.41	$ 3,453.79	*$ 339.59*	$ 4,696.41	$ 3,453.79	*$ 339.59*	$ -	$ -	*$ -*	$ 4,696.41	$ 3,453.79	*$ 339.59*
Generation Credit:				$ (1,075.62)	$ (1,791.86)	*$ (119.48)*	$ (1,075.62)	$ (1,791.86)	*$ (119.48)*	$ -	$ -	*$ -*	$ (1,075.62)	$ (1,791.86)	*$ (119.48)*
Total Generation:	$ 31,756.24	$ 29,506.70	*$ 2,552.62*	$ 3,620.79	$ 1,661.94	*$ 220.11*	$ 3,620.79	$ 1,661.94	*$ 220.11*	$ -	$ -	*$ -*	$ 3,620.79	$ 1,661.94	*$ 220.11*
Total Charges:	$ 37,528.98	$ 35,192.34	*$ 3,030.06*	$ 6,800.04	$ 4,829.65	*$ 484.57*	$ 10,901.26	$ 8,836.22	*$ 822.40*	$ 4,101.23	$ 4,006.57	*$ 337.82*	$ 7,771.33	$ 5,706.28	*$ 561.57*
Utility Savings:			*$ 2,545.49*	$ 30,728.95	$ 30,362.70	*$ 2,545.49*	$ 26,627.72	$ 26,356.13	*$ 2,207.66*	$ (4,101.23)	$ (4,006.57)	*$ (337.82)*	$ 29,757.66	$ 29,486.06	*$ 2,468.49*
MWh Produced:			*20.43*	246.394	243.85	*20.43*	246.394	243.85	*20.43*	$ -	$ -	*$ -*	246.394	243.85	*20.43*
REC Value:				$ 8,860.92	$ 8,752.86	$ 735.77	$ 8,860.92	$ 8,752.86	$ 735.77	$ -	$ -	*$ -*	$ 8,860.92	$ 8,752.86	$ 735.77
Total Savings:			*$ 3,281.26*	$ 39,589.87	$ 39,115.56	*$ 3,281.26*	$ 35,488.64	$ 35,108.99	*$ 2,943.43*	$ (4,101.23)	$ (4,006.57)	*$ (337.82)*	$ 38,618.58	$ 38,238.92	*$ 3,204.26*

RESPONSES OF
KELLY ROAD SOLAR, LLC, LANCASTER AVENUE SOLAR, LLC,
AND TWILIGHT RENEWABLES, LLC
TO INTERROGATORIES AND REQUESTS
FOR PRODUCTION OF DOCUMENTS
TO CITIZENS' ELECTRIC COMPANY OF LEWISBURG, PA, SET II

DOCKET NO. R-2025-3054394

Citizens'-SP-II-15

Reference Statement No. 1, page 6, lines 17-19.

A. Explain how a 480kW solar array is similar to a non-generation customer of less than 100kW demand.
B. Explain what benefits the flexibility and grid support functions of a solar array provide, and how does the ability to "go offline immediately" benefit the distribution system?

RESPONSE:

A. (1) High Voltage tap into the 12kV System with similar primary wire size. (1) transformer to install. (1) customer bill to produce, meter to read etc. (administrative side).

B. The inverters installed on all 6 projects are UL 1741-SA & SB compliant. PPL provides DER Communication devices that can alter settings of inverters based on grid conditions to provide grid support. Citizens' electric has no such infrastructure to fully utilize the capabilities of the inverters, at no fault of the solar projects.

UL 1741-SA was published in conjunction with California Rule 21 Phase 1 requirements. These safety tests certify the "smart inverter" grid support functionality needed to modernize the grid through widespread DER integration. The testing requirements for UL 1741-SA are as follows:

- Anti-islanding
- Low/high-voltage ride-through (L/HVRT)
- Low/high-frequency ride-through (L/HFRT)
- Specified power factor (SPF)
- Volt/VAR mode
- Volt/watt mode
- Frequency/watt mode
- Ramp rate

UL 1741-SB introduced an interoperability conformance test in accordance with IEEE 1547.1 2020. Conformance can be achieved through either DNP3, IEEE 2030.5, or SunSpec Modbus communications protocols, which are used to store or

RESPONSES OF
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send information and to control adjustable inverter functions. The testing requirements for UL 1741-SB are more stringent and include the following in addition to the requirements defined above for UL 1741-SA certification:

- Watt/VAR mode
- Voltage magnitude and time trip
- Frequency magnitude and time trip
- EMI
- Surge
- Rate of change of frequency (ROCOF)
- Dynamic voltage support
- Enter service
- Synchronization
- Open phase
- Harmonics
- DC injection
- Ground fault overvoltage (GFOV)
- Load rejection overvoltage (LROV)
- Prioritization of DER responses
- Fault current
- Persistence of DER parameter setting

The solar-only services are not critical loads, that would not require off hour outage response to get placed back in service. The inverters, even if the DER capabilities are not fully utilized by the utility, will not operate if voltage, frequency, etc. is out of acceptable parameters

Provided By: Brett Nolt

Dated: August 4, 2025

Scenario	Description	Total Distribution Revenue
A	450kWAC Rack Mounted SPV Array (Parameters provided in spreadsheet) with no co-located load.	$ 37,434.00
B	Scenario A SPV system with co-located ~420kWAC 3ph GLP-3 load.	$ 41,316.71
C	Scenario A SPV system with co-located 562MWh annual usage 3ph GLP-3 load.	$ 37,434.00

Month	Rated Output	Usage	*month*	Block 1 kWh	Block 2 kWh	Customer Charge	Block 1 Charge	Block 2 Charge	Demand Charge	Distribution Total
Jul-23	450									
Aug-23	450									
Sep-23	450									
Oct-23	450									
Nov-23	450									
Dec-23	450									
Jan-24	450									
Feb-24	450									
Mar-24	450									
Apr-24	450									
May-24	450									
Jun-24	450	(60,609.69)	6	-	-	$ 100.00	$ -	$ -	$ 3,019.50	$ 3,119.50
Jul-24	450	(66,389.19)	7	-	-	$ 100.00	$ -	$ -	$ 3,019.50	$ 3,119.50
Aug-24	450	(62,920.00)	8	-	-	$ 100.00	$ -	$ -	$ 3,019.50	$ 3,119.50
Sep-24	450	(62,012.57)	9	-	-	$ 100.00	$ -	$ -	$ 3,019.50	$ 3,119.50
Oct-24	450	(53,383.66)	10	-	-	$ 100.00	$ -	$ -	$ 3,019.50	$ 3,119.50
Nov-24	450	(46,474.29)	11	-	-	$ 100.00	$ -	$ -	$ 3,019.50	$ 3,119.50
Dec-24	450	(33,821.61)	12	-	-	$ 100.00	$ -	$ -	$ 3,019.50	$ 3,119.50
Jan-25	450	(43,503.87)	1	-	-	$ 100.00	$ -	$ -	$ 3,019.50	$ 3,119.50
Feb-25	450	(48,618.41)	2	-	-	$ 100.00	$ -	$ -	$ 3,019.50	$ 3,119.50
Mar-25	450	(60,915.94)	3	-	-	$ 100.00	$ -	$ -	$ 3,019.50	$ 3,119.50
Apr-25	450	(58,481.23)	4	-	-	$ 100.00	$ -	$ -	$ 3,019.50	$ 3,119.50
May-25	450	(64,158.07)	5	-	-	$ 100.00	$ -	$ -	$ 3,019.50	$ 3,119.50
						$ 1,200.00	$ -	$ -	$ 36,234.00	**$ 37,434.00**

Month	Metered Demand	Rated Output	Billed Demand	Usage	Bank Usage	Billed Usage	Bank	*month*	Block 1 kWh	Block 2 kWh	Customer Charge	Block 1 Charge	Block 2 Charge	Demand Charge	Distribution Total
Jul-23	380.16	450													
Aug-23	405.12	450													
Sep-23	383.52	450													
Oct-23	400.32	450													
Nov-23	365.28	450													
Dec-23	290.88	450													
Jan-24	283.68	450													
Feb-24	290.40	450													
Mar-24	309.12	450													
Apr-24	302.40	450													
May-24	351.84	450													
Jun-24	380.64	450	450	156,638.60	-	156,638.60	-	6	13,500	143,139	$ 100.00	$ 159.98	$ 184.65	$ 3,019.50	$ 3,464.12
Jul-24	409.44	450	450	172,509.98	-	172,509.98	-	7	13,500	159,010	$ 100.00	$ 159.98	$ 205.12	$ 3,019.50	$ 3,484.60
Aug-24	423.36	450	450	166,565.71	-	166,565.71	-	8	13,500	153,066	$ 100.00	$ 159.98	$ 197.45	$ 3,019.50	$ 3,476.93
Sep-24	400.80	450	450	142,197.49	-	142,197.49	-	9	13,500	128,697	$ 100.00	$ 159.98	$ 166.02	$ 3,019.50	$ 3,445.49
Oct-24	361.44	450	450	137,887.82	-	137,887.82	-	10	13,500	124,388	$ 100.00	$ 159.98	$ 160.46	$ 3,019.50	$ 3,439.94
Nov-24	333.12	450	450	132,966.37	-	132,966.37	-	11	13,500	119,466	$ 100.00	$ 159.98	$ 154.11	$ 3,019.50	$ 3,433.59
Dec-24	328.32	450	450	147,002.28	-	147,002.28	-	12	13,500	133,502	$ 100.00	$ 159.98	$ 172.22	$ 3,019.50	$ 3,451.69
Jan-25	279.84	450	450	134,956.96	-	134,956.96	-	1	13,500	121,457	$ 100.00	$ 159.98	$ 156.68	$ 3,019.50	$ 3,436.15
Feb-25	274.56	450	450	114,358.09	-	114,358.09	-	2	13,500	100,858	$ 100.00	$ 159.98	$ 130.11	$ 3,019.50	$ 3,409.58
Mar-25	282.72	450	450	121,644.20	-	121,644.20	-	3	13,500	108,144	$ 100.00	$ 159.98	$ 139.51	$ 3,019.50	$ 3,418.98
Apr-25	310.08	450	450	123,616.30	-	123,616.30	-	4	13,500	110,116	$ 100.00	$ 159.98	$ 142.05	$ 3,019.50	$ 3,421.53
May-25	330.72	450	450	133,373.19	-	133,373.19	-	5	13,500	119,873	$ 100.00	$ 159.98	$ 154.64	$ 3,019.50	$ 3,434.11
											$ 1,200.00	$ 1,919.70	$ 1,963.01	$ 36,234.00	**$ 41,316.71**

Month	Metered Demand	Rated Output	Billed Demand	Usage	Bank Usage	Billed Usage	Bank	*month*	Block 1 kWh	Block 2 kWh	Customer Charge	Block 1 Charge	Block 2 Charge	Demand Charge	Distribution Total
Jul-23	115.28	450													
Aug-23	157.94	450													
Sep-23	158.44	450													
Oct-23	156.10	450													
Nov-23	105.47	450													
Dec-23	106.01	450													
Jan-24	93.37	450													
Feb-24	93.39	450													
Mar-24	103.55	450													
Apr-24	98.90	450													
May-24	117.51	450													
Jun-24	118.21	450	450	(3,201.41)	-	-	(3,201.41)	6	-	-	$ 100.00	$ -	$ -	$ 3,019.50	$ 3,119.50
Jul-24	161.95	450	450	(4,058.83)	-	-	(7,260.24)	7	-	-	$ 100.00	$ -	$ -	$ 3,019.50	$ 3,119.50
Aug-24	162.48	450	450	(11,128.01)	-	-	(18,388.25)	8	-	-	$ 100.00	$ -	$ -	$ 3,019.50	$ 3,119.50
Sep-24	160.08	450	450	(17,640.58)	-	-	(36,028.83)	9	-	-	$ 100.00	$ -	$ -	$ 3,019.50	$ 3,119.50
Oct-24	108.12	450	450	(8,843.13)	-	-	(44,871.96)	10	-	-	$ 100.00	$ -	$ -	$ 3,019.50	$ 3,119.50
Nov-24	108.72	450	450	(4,332.20)	-	-	(49,204.16)	11	-	-	$ 100.00	$ -	$ -	$ 3,019.50	$ 3,119.50
Dec-24	95.76	450	450	8,883.64	8,883.64	-	(40,320.52)	12	-	-	$ 100.00	$ -	$ -	$ 3,019.50	$ 3,119.50
Jan-25	95.76	450	450	(273.04)	-	-	(40,593.56)	1	-	-	$ 100.00	$ -	$ -	$ 3,019.50	$ 3,119.50
Feb-25	106.20	450	450	(9,195.44)	-	-	(49,789.00)	2	-	-	$ 100.00	$ -	$ -	$ 3,019.50	$ 3,119.50
Mar-25	101.40	450	450	(16,942.67)	-	-	(66,731.67)	3	-	-	$ 100.00	$ -	$ -	$ 3,019.50	$ 3,119.50
Apr-25	120.48	450	450	(14,231.33)	-	-	(80,963.00)	4	-	-	$ 100.00	$ -	$ -	$ 3,019.50	$ 3,119.50
May-25	121.20	450	450	(17,645.60)	-	-	(98,608.60)	5	-	-	$ 100.00	$ -	$ -	$ 3,019.50	$ 3,119.50
											$ 1,200.00	$ -	$ -	$ 36,234.00	**$ 37,434.00**

BEFORE

THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	**:**	
	:	
v.	**:**	**Docket No. R-2025-3054394**
	:	
Citizens' Electric Company of Lewisburg, PA	**:**	

SURREBUTTAL TESTIMONY

OF

NATHAN JOHNSON

ON BEHALF OF

CITIZENS' ELECTRIC COMPANY OF LEWISBURG, PA

AUGUST 28, 2025

BEFORE

THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	**:**	
	:	
v.	**:**	**Docket No. R-2025-3054394**
	:	
Citizens' Electric Company of Lewisburg, PA	**:**	

SURREBUTTAL TESTIMONY OF NATHAN JOHNSON
ON BEHALF OF CITIZENS' ELECTRIC COMPANY OF LEWISBURG, PA

Q. Please state your name and business address.

A. My name is Nathan (Nate) Johnson. My business address is 1775 Industrial Blvd., Lewisburg, Pennsylvania.

Q. Are you the same Nathan Johnson who previously submitted Direct Testimony in this proceeding on behalf of Citizens' Electric Company of Lewisburg, PA ("Citizens'" or "Company")?

A. Yes. Terms defined in my Direct Testimony or my Rebuttal Testimony have the same meaning in this Surrebuttal Testimony.

Q. What is the purpose of your Surrebuttal Testimony?

A. I will respond to the Rebuttal Testimony submitted by Zach Teti on behalf of the Office of Consumer Advocate ("OCA").

Q. Please summarize Mr. Teti's testimony.

A. Mr. Teti supports the Company's proposal to include a customer-generator’s generating capacity in the determination of Billing Demand but requested additional information regarding how Citizens' Generation Supply Service Rate 2 ("GSSR-2") operates. I am

providing a basic summary of our default service purchasing strategy as background to support the explanation of how the GSSR-2 operates.

Q. Please discuss the Company's default service procurement and retail pricing approach.

A. Under the Company's current Joint Default Service Plan ("DSP") with Wellsboro Electric Company ("Wellsboro"), the Commission authorized Citizens' and Wellsboro (collectively, "Companies") to conduct a joint Request for Proposal ("RFP") to obtain a single wholesale supplier for the default service load in each territory. The supplier provides Load-Following Full Requirements ("FR") service for each respective Company's default service customers under a 4-year contract for this supply (June 1, 2025 through May 31, 2029). The supplier serves as the PJM Load Serving Entity ("LSE") for the default service load. The wholesale service is priced as follows:

- Energy (as measured at the wholesale meter for the Citizens' or Wellsboro Aggregate Bus, less kWh for customers supplied by Electric Generation Suppliers ("EGS"):
  - Residential and Small Commercial and Industrial Default Service: The energy component is layered and periodically based on PJM West Hub on-peak monthly forward pricing on Trigger Dates determined by the Companies; the wholesale rate formula will assume a straight passthrough of the mathematical average of the monthly on-peak per MWh strip pricing for all MWh sold to customers during the twelve-month (12-month) pricing period. This results in a 'laddered approach' to attempt to mitigate against overly sharp pricing swings by relying on a twelve-month (12-month) average. The Companies use the Intercontinental Exchange ("ICE") to set the strip prices. The specific schedule for the layering is attached as Exhibit__(NJ-1SR).
  - Commercial and Industrial Hourly Default Service: The energy component of Hourly Priced Service ("HPS") will be the real-time hourly PJM Locational Marginal Price ("LMP") for the PJM West Hub.
- Capacity (Reliability Pricing Model, Locational Reliability, Capacity Performance): Passthrough of actual monthly costs for the default service load, without markup.

- Network Integrated Transmission Service ("NITS"): Passthrough of actual monthly costs for the default service load, without markup.

- Regional Transmission Expansion Plan/Transmission Enhancement Costs ("RTEP/TEC"): Passthrough of actual monthly costs for the default service load, without markup.

- Supplier Adder: Per-kWh charge applicable to both fixed and hourly energy supply that covers all other costs to deliver default service power to the Citizens' or Wellsboro Aggregate Bus, including congestion, marginal losses, Alternative Energy Portfolio Standards ("AEPS") Act compliance, and transmission losses, as well as all risks associated with default service customer usage variability, customer migration (switching to an EGS for supply service or returning to default service as permitted under the Companies' tariffs and Pennsylvania law) and deviations between the forward pricing and actual costs. The Supplier Adder may be different for each territory but remains fixed for the term of the wholesale contract.

Q. Is the Supplier Adder the same for all customer classes within a service territory?

A. Yes.

Q. How do the Companies choose the wholesale supplier for each territory?

A. The suppliers bid based on the Supplier Adder, with the contract going to the lowest qualified bidder in each territory.

Q. Please explain the pricing components of the Generation Supply Service Rate 1 ("GSSR-1")?

A. The GSSR-1 consists of: (1) projected Purchased Power Costs (the fixed energy rate (adjusted for distribution losses) + the Supplier Adder + (Projected NITS + Projected RTEP/TEC + Projected Capacity) Costs for the GSSR-1 class + Company Administrative Costs); plus or minus (2) the Reconciliation Period E-factor; divided by (3) projected metered sales to GSSR-1 default service customers; times (4) a Gross Receipts Tax ("GRT") gross-up. This rate is adjusted every 6 months, although the Supplier Adder would remain fixed throughout the 4-year DSP period. The fixed energy rate is based on the PJM

West Hub on-peak monthly forward pricing as measured on predetermined Trigger Dates. The GSSR-1 cost components are reflected in the existing Citizens' tariff.

Q. How does the Company project transmission costs?

A. The transmission costs for the GSSR-1 are projected by multiplying the Company's Transmission Obligation for the projected default services load by the Federal Energy Regulatory Commission ("FERC")-approved transmission rate applicable to the PPL Zone. A similar process occurs for RTEP/TEC.

Q. How do the Companies project the costs for capacity charges?

A. We pay for capacity daily, as determined by PJM. Our costs are based on: (1) the Company service territory’s PJM-assigned Capacity Obligation for the default service load; and (2) the Net Load Price for its Locational Deliverability Area as determined in the PJM Reliability Pricing Model ("RPM") auctions. Capacity also includes the Capacity Performance Costs (or credits). To project the costs for each six-month (6-month) pricing period, we multiply the anticipated Capacity Obligation for the Company's default service customers on the GSSR-1, by the Net Load Price (stated on a $/MW-day basis), and then by the number of days in the pricing period.

Q. How does PJM assign the Transmission Obligation and Capacity Obligation?

A. The Transmission Obligation and Capacity Obligation are determined based on the Company service territory's performance during the transmission and capacity peak hours. The Capacity Obligation is assigned based on the Company service territory's performance during the Regional Transmission Organization peak hours from June 1 through September 30. The obligation is provided to Citizens' in late November or December of the year. The

obligation will then apply for the following capacity delivery year, which runs from June 1 through May 31.

The Transmission Obligation is assigned based on the performance during the PPL Zonal peaks. These peaks can occur at any time during the year. In many years, those hours occur during the winter.

Attached as Exhibit__(NJ-2SR) is a compilation of the dates and hours that determined the obligations for Citizens' service territory for the last five years.

Q. How do the pricing components of the GSSR-2 differ from the GSSR-1?

A. The basic cost structure is similar, but the GSSR-2 was designed to recover actual costs rather than projections. First, the GSSR-2 includes a different energy component since commercial and industrial customers with a peak demand above 400 kW take Hourly Price Service ("HPS"), based on the real-time PJM LMP for the PJM West Hub. Also, while the GSSR-1 assigns a fixed per-kWh charge for NITS, Capacity, and RTEP/TEC based on projected kWh load, the GSSR-2 passes through NITS, Capacity, and RTEP/TEC costs on a per-kW basis, reflecting the individual PJM allocations for each customer. Accordingly, the GSSR-2 costs are made up of: (1) the real-time HPS rate as calculated by PJM for the PJM West Hub (adjusted for distribution losses); **plus** (2) the per-kWh Supplier Adder; **plus** (3) the per-kWh Company Administrative Costs; **plus** (4) a per-kW Transmission, RTEP/TEC and Capacity charge based on the applicable PJM rates and each customer's PJM NITS and Capacity obligations; **plus** (5) the GSSR-2 E-factor; **times** (6) a GRT gross-up. The kWh charges will be billed using the customer's metered hourly usage.

Q. How does Citizens' calculate the Transmission and Capacity obligations for each GSSR-2 account?

A. We do this based on the account's performance during the same hours that PJM uses to calculate the service territory Transmission and Capacity Obligations. Each GSSR-2 account is assigned an obligation based on its individual average contribution to system demand for each of the five capacity or transmission peak hours, adjusted for losses and PJM scaling/reconciliation.

Q. Mr. Teti asked how a net-metered customer on the GSSR-2 default service rate will be charged for generation service. Please discuss.

A. Due to the hourly variability of the GSSR-2 rate, the Company must first determine charges for all consumed energy as described below. Credit for net-metered generation exports will be calculated and applied separately, which I will address later in my testimony. GSSR-2 Charges are determined as follows:

- Energy Charge per kWh: The customer will be charged for each hour of net consumption at the real-time LMP for that hour.

- Capacity Charge: The customer will be charged for capacity each month based on their prior-year peak load contribution.

- Transmission Charge: The customer will be charged for transmission each month based on their prior-year Network Service Peak Load ("NSPL") contribution.

- Regional Transmission Expansion Plan/Transmission Enhancement Charge: The customer will be charged for RTEP/TEC each month based on their prior-year NSPL contribution.

- GSSR-2 E-Factor: The GSSR-2 E-Factor is applied to all hours of net consumption by the customer-generator. The E-Factor is per-kWh rate based on under- or over-collected GSSR-2 revenues from the prior reconciliation period, divided across projected kWh consumption by the GSSR-2 rate class for the current reconciliation period.

- GSSR-2 Administrative Charge: The GSSR-2 Administrative Charge is applied to all hours of net consumption by the customer-generator.

Q. For clarity, will a net-metered account on GSSR-2 pay a transmission and/or capacity charge?

A. This answer depends on what the account status is during the peak hours that determine the capacity and transmission obligations. If the average performance during the peaks results in a positive demand being consumed, then the account will have the transmission and/or capacity charge for the subsequent year. If the average performance during the peaks does not result in a positive demand being consumed, then the account will have a zero obligation, and no capacity and/or transmission charges the subsequent year.

Q. Why are the account-level obligations either zero or a positive charge?

A. For retail accounts, PJM recognizes only positive (or zero) obligations. All of our customers have the ability to shop for generation supply. When that happens, we transfer the responsibility for that account at PJM to the EGS. We cannot transfer a negative capacity or transmission obligation to the EGS.

Q. Please respond to Mr. Teti's request for an explanation of how the net metering process will be administered for the GSSR-2 account?

A. The Company proposes to credit the customer-generator for each hour of net export during the billing period at the real-time LMP for that hour. Credit will be applied against the hourly LMP charges on the customer's bill for the current billing period. If the hourly export credit exceeds the hourly consumption charges for a billing period, the excess credit will be 'banked'—carried forward—for credit against future hourly consumption charges. If any credit remains following the last bill of the energy year (May), a credit will be issued to the customer-generator for that amount, and the customer-generator will start the new energy year with a zero balance in their generation "bank."

The customer-generator also receives a credit applied to the kWh-based distribution charges on its bill. That kWh-based distribution credit can carry forward from month-to-month as it currently does with existing GSSR-1 customers.

Q. Do you agree with Mr. Teti's discussion of the "risk premium" associated with keeping medium and larger customer-generators on the GSSR-1 rate?

A. Yes, however, the impact would be more directly reflected in the wholesale costs for the GSSR-1 rate, rather than the wholesale supplier's basis that they bid in the RFP. Compensating the larger customer-generators at the GSSR-1 rate does not incentivize the customer-generator to maximize its exports during the peak hours that determine the capacity and transmission obligations. From an economic standpoint and depending on the wholesale capacity and transmission rates, the customer-generator may benefit more by withholding its generation during those peaks, thus increasing the capacity and transmission obligations for the GSSR-1 class and increasing the GSSR-1 Price to Compare. This risk premium can be avoided by treating customer-generators with Gross Generator Ratings over 400 kW as GSSR-2 customers, where similar energy-consuming customers are placed.

Q. Is Mr. Teti correct in his assertion that 'Residential Customers with DER' will be substantially unaffected by proposed billing demand methodology?

A. I interpret Mr. Teti's statement as confirmation that the proposed billing demand methodology will not adversely affect residential customers, which I agree with. The proposal applies only to non-residential accounts. In addition, as discussed in both Mr. Teti's and my testimony, residential accounts—which are all served under the GSSR-1

rate—pay higher default service rates as a result of net metering refunds for excess generation. The proposed billing demand methodology will remove this burden.

Q. Does this conclude your Surrebuttal Testimony?

A. Yes.

BEFORE

THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	**:**	
	:	
v.	**:**	**Docket No. R-2025-3054394**
	:	
Citizens' Electric Company of Lewisburg, PA	**:**	

EXHIBITS

OF

NATHAN JOHNSON

ON BEHALF OF

CITIZENS' ELECTRIC COMPANY OF LEWISBURG, PA

AUGUST 28, 2025

Citizens' Statement No. 4RJ

BEFORE

THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	**:**	
	:	
v.	**:**	**Docket No. R-2025-3054394**
	:	
Citizens' Electric Company of Lewisburg, PA	**:**	

REJOINDER TESTIMONY

AND EXHIBIT

OF

NATHAN JOHNSON

ON BEHALF OF

CITIZENS' ELECTRIC COMPANY OF LEWISBURG, PA

September 3, 2025

BEFORE

THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	**:**	
	:	
v.	**:**	**Docket No. R-2025-3054394**
	:	
Citizens' Electric Company of Lewisburg, PA	**:**	

REJOINDER TESTIMONY OF NATHAN JOHNSON
ON BEHALF OF CITIZENS' ELECTRIC COMPANY OF LEWISBURG, PA

Q. Please state your name and business address.

A. My name is Nathan (Nate) Johnson. My business address is 1775 Industrial Blvd., Lewisburg, Pennsylvania.

Q. Are you the same Nathan Johnson who previously submitted Direct Testimony in this proceeding on behalf of Citizens' Electric Company of Lewisburg, PA ("Citizens'" or "Company")?

A. Yes. Terms defined in my Direct Testimony, Rebuttal Testimony or Surrebuttal Testimony have the same meaning in this Rejoinder Testimony.

Q. What is the purpose of your Rejoinder Testimony?

A. I will respond to the Surrebuttal Testimony submitted by Brett Nolt and Kevin Lucas on behalf of the Solar Projects.

RESPONSES TO MR. NOLT

Q. In Mr. Nolt's Surrebuttal Testimony, page 6, Mr. Nolt claims that the Company relied entirely on the Commission's decision in the UGI Utilities, Inc. – Electric Division ("UGI") default service proceeding in submitting the proposal. Is this correct?

A. No. The Commission's UGI decision prompted us to look at the default service classification for customer-generators; however, we also relied on our own assessment of how customer-generators should be treated for both default service and distribution service cost recovery.

Q. Is it "reckless" for Citizens' to consider the implications of Commission decisions for other utilities?

A. No. We monitor many Commission decisions and statements issued at Public Meetings to assess how the Commission prefers to address rate and service issues. As a regulated utility, we try to be responsive to Commission trends, preferences and orders.

Q. On page 6, lines 17-19, Mr. Nolt claims that the Company is charging $22,000 per year (or $660,000 over the life of the system) for facilities that were paid in full by the customer before the generation was active. Is this accurate?

A. No. Mr. Nolt assumes a 30-year life for the solar generation. The facilities that are installed Year 1 on the Citizens' system, as well as existing facilities already in place that nonetheless still accommodate the new generation, require ongoing maintenance, including potential replacement if the equipment fails or becomes inoperable. The customer generator does not pay if we have to replace that equipment. The distribution rates charged to the customer-generator and others also cover ongoing maintenance of that specific equipment

as well as the other portions of the distribution system and services that are needed to serve the customer-generation.

Q. On pages 7 and 11, Mr. Nolt discusses that other Pennsylvania utilities operated distributed energy resource programs that look at power quality and grid reliability. Please discuss those programs.

A. The only program that I am aware of is a pilot program being conducted by PPL Electric Utilities Corporation ("PPL"). I reviewed the most recent program evaluation report submitted by PPL, which our counsel has marked as Exhibit__(NJ-1RJ).

Based on this report, the PPL program is very unique and is only a pilot program. Although PPL has claimed reduced capital and O&M expenditures, the upfront implementation costs are very substantial. PPL has over a million customers and 1000s of miles of distribution equipment, while we have only about 7,200 customers and less than 400 miles of line. Even if the PPL program is cost-effective, it is not clear that it will be scalable to our size.

Q. On page 8, Mr. Nolt claims that the GSSR-2 is not a retail rate. Do you agree?

A. No. It is charged to retail customers. It is not a wholesale rate, which is a sale for resale. Retail sales are subject to the PUC's jurisdiction and are subject to certain taxes. The GSSR-2 is such a rate.

Q. On pages 8-9, Mr. Nolt discusses virtual net metering by agricultural customers. Do you have any response?

A. Mr. Nolt discusses another way that a solar customer may be leaning on the distribution system to offset usage at other locations. In this situation, rather than the distribution system operating as a virtual storage bank for the later return of power, the excess is being virtually "wheeled" to other accounts. The aim of our distribution proposal is to apportion

distribution costs among various customers when the distribution system is being put to new uses such as this. We believe it is fair, just and reasonable to charge the customer-generator for its share of the distribution costs.

Q. On page 10, Mr. Nolt suggests that he could not request to get his deposits back. Please respond.

A. Mr. Nolt suggests that the only way his deposit could have been refunded was for Citizens' to return it in its entirety and strand ratepayers with the cost of unused facilities. This is incorrect; had Mr. Nolt requested to stop construction, the Company would have refunded him for any costs not yet incurred. We would also have reviewed the construction already completed and materials already purchased to determine if any construction or materials could be repurposed to provide benefits to other ratepayers, and credited Mr. Nolt accordingly.

RESPONSES TO MR. LUCAS

Q. On page 13 of his surrebuttal, Mr Lucas claims that customer generators cannot respond to price signals provided by the GSSR-2 tariff because it is a "real time" rate. Do you agree?

A. No. Day-ahead hourly pricing is available from PJM Interconnection, L.L.C ("PJM") that provides a good correlation to the actual real-time pricing the following day. PJM also issues maximum generation and load management alerts in advance that assist customers in peak-shaving or other responsive actions. Outside of PJM, electronic services are available that will provide the Locational Marginal Price ("LMP") on a constant basis during the day and project peak hours. It is not simply a price signal that is completely opaque to the customer when it is happening. Monitoring the information that is available

from PJM and third parties can provide the customer-generator with the directional trend for the pricing (up or down) so they can respond.

Q. Do the "needle peaks" in 5-minute LMP create substantial uncertainty for customers?

A. No. Using the integrated hourly LMP smooths the impact of the "needle peaks" cited by Mr. Lucas.

Q. On pages 14-15, Mr. Lucas suggests that a customer-generator could not intentionally act to withhold its generation during the capacity and transmission peaks because the peak hours are not published until after the fact. Do you agree?

A. No. Some larger customers pursue "peak shaving" strategies to reduce usage during the peak hours even though they do not know the precise hours in advance. If larger customers can predict those hours with relative accuracy to peak shave, then the customer-generators or their consultants can develop similar strategies for their operations.

Q. Mr. Lucas asserts that the cost impact of withholding on the customer-generator would not justify this strategy. Please comment.

A. That is highly dependent on the generator size and PJM capacity and transmission prices. The key takeaway, however, is that the GSSR-2 rate structure provides the customer-generator with better signals to be producing at the peaks than the GSSR-1 structure does.

Q. Is Mr. Lucas' explanation of the impact of the operation of the Company's GSSR-1 on page 17 correct?

A. No. Mr. Lucas ignores the impact of the customer-generators and net metering on the sales used to determine the GSSR-1 rates. Just because a customer-generator withholds its

exports during the peaks does not mean that account is importing extra energy from the Company during those times.

Q. On pages 18-20, Mr. Lucas refutes the assertion that customer-generators are manipulating the market price of capacity and transmission services. Did you make this claim in your Rebuttal Testimony?

A. No. Mr. Lucas has attempted to refute an argument that we did not make. It isn't clear why he needed to do so since we did not make that argument.

Q. Mr. Lucas claims that the billing demand proposal discriminates against customer-generators in favor of other customers. Please comment.

A. I would suggest that, without the billing demand proposal, the Commission will be discriminating in favor or the customer-generators at the expense of other GLP-1 and GLP-3 customers. Ultimately, the Commission must decide which side of the argument is accurate.

Q. Mr. Lucas, on page 25 of his Surrebuttal Testimony, claims that the Company has not performed an analysis in support of its proposal. Do you agree?

A. No. We analyzed the planning implications of the customer-generators and how the use is similar to a similarly-sized, use-only customer. In the seven (7) years that I have been employed by Citizens', planning and overseeing the distribution system have been my responsibility.

In addition, Mr. Lucas lists several inaccurate or misleading suggestions regarding analysis for the proposal. Mr. Gorman will address why incremental cost studies and marginal cost studies are not relevant to his case. He also will explain that the absence of a "cost of

service study comparing the cost responsibility using actual metered energy flows or its GGR Billing Demand methodology" is not dispositive.

Mr. Lucas' statement that the customer-generator must pay for a study and may be required to pay for system upgrades to safely interconnect ignores the other ongoing costs, maintenance and equipment replacements that are required over the 30-year life of the generation. In addition, although the peak demand on our feeders has not been increased to date, this does not mean that we admit that a customer-generator could not increase the peak demand on a feeder.

Finally, the fact that other utilities do not use this definition of Billing Demand is not dispositive. Until the Commission approved the UGI settlement, the same could be said for UGI's proposal.

Q. Mr. Lucas disputes that customer-generators would be confused if the Billing Demand for the generation and distribution were calculated using two different definitions. Do you have any comments?

A. Mr. Lucas notes that there are 15 non-residential customer-generators on our distribution system. As I explained in my testimony, once the Commission issued the decision in the UGI case, we believed that following that definition would reduce confusion. We are also willing to use the bi-directional demand for those customers and have agreed with the Office of Consumer Advocate, Bureau of Investigation and Enforcement, and the Office of Small Business Advocate to a non-unanimous settlement in this matter that uses bi-directional demand.

Q. Please explain the difference between the originally proposed use of 'Gross Generator Rating' for billing demand and the Company's revised proposal to use 'bi-directional metered demand.'

A. A customer-generator's 'Gross Generator Rating' is the rated maximum output of the generation system and is essentially fixed (unless the customer-generator changes their output and reapplies for interconnection) for the life of the generator. Bi-directional metered demand—which will require programming changes to the Company's AMI system—measures the actual peak power flows of both imports and exports and provides the single highest peak for the billing calculation. This is a dynamic measurement and will likely change both seasonally and over the life of a generation system.

Q. So, do you agree with Mr. Lucas' Surrebuttal Testimony at page 11 that it is feasible to use the bi-directional demand for both the distribution billing and determining the default service classification?

A. Yes, and under the settlement, we are willing to either reprogram the existing meters to measure the bi-directional demand or procure meters with this additional functionality for the non-residential customer-generators on the system.

Q. On page 30 of Mr. Lucas' Surrebuttal, he indicates that the existence of net metered customer-generators did not impact the most recent default service solicitation, as evidenced by the negative supplier basis that resulted. Do you agree?

A. The bidders were given historic load information for the default service solicitation as of January 2025. That historic load information would not have included four of Mr. Nolt's projects, which are quite sizable. The load information for future solicitations will begin to incorporate Mr. Nolt's data.

Based on our analysis, the negative supplier adder reflects two factors. First, there is generally a negative correlation between the PJM West wholesale pricing that is used in the GSSR-1 and GSSR-2 rate mechanisms and the real time pricing at our Aggregate Bus. In other words, the hourly pricing at the Citizens' location is generally lower than the hourly pricing at PJM West hub.

Second, the wholesale supplier is able to use Financial Transmission Rights ("FTRs") for our default service load. This enables them to make money at PJM that offsets their costs to provide the wholesale supply for our load.

Q. Finally, on page 47 of his Surrebuttal Testimony, Mr. Lucas suggests that the Commission delay its consideration of this proposal until the Company's next default service proceeding. Do you agree?

A. Absolutely not. We filed this proposal on April 30, 2025. Mr. Nolt and Mr. Lucas had ample opportunity to explore the proposal for both the distribution and generation proposals prior to submitting their Direct Testimony. In my Surrebuttal Testimony, I addressed Mr. Teti's concerns raised in the Rebuttal Testimony stage of this proceeding. Waiting an additional three or four years to litigate this issue to a decision is not appropriate and will only magnify the impact of large customer-generators on our system.

Q. Does this conclude your Rejoinder Testimony?

A. Yes.

BEFORE

THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	**:**	
	:	
v.	**:**	**Docket No. R-2025-3054394**
	:	
Citizens' Electric Company of Lewisburg, PA	**:**	

EXHIBIT

OF

NATHAN JOHNSON

ON BEHALF OF

CITIZENS' ELECTRIC COMPANY OF LEWISBURG, PA

September 3, 2025

PPL Electric Utilities Corporation

2025 DER Management Report

to the

Pennsylvania Public Utility Commission

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Introduction

PPL Electric Utilities Corporation ("PPL Electric" or the "Company") hereby submits this annual report for Program Year 3 ("PY3") of its Distributed Energy Resource ("DER") Management Pilot Program ("DER Pilot" or "Pilot"). The DER Pilot is the first of its kind in North America, communicating with and managing DERs down to the individual residential installation level for the purposes of improving power quality, safety, and hosting capacity, expanding operational awareness, and avoiding otherwise necessary capital or maintenance expenses. The DER Pilot's goal has been to understand, demonstrate, and quantify the benefits of active management, their associated costs, and the overall impact on the distribution system and DERs' performance. The Pennsylvania Public Utility Commission's ("Commission" or "PUC") authorization of this program has yielded significant benefits and will continue to enable the growth of clean energy in Pennsylvania while maintaining system reliability, power quality, and affordability.

During the DER Pilot's PY3, which spanned March 22, 2024, to March 21, 2025, the Company achieved significant progress in the integration and management of DERs, pursuant to the goals of the Pilot. PY3 continued the DER Pilot's success in executing DER interconnection and management processes, along with thorough analysis, documentation, and forecasting of the Pilot's benefits. Over PY3, the Company's service territory saw 3,976 new solar DER installations with a total nameplate capacity of 74.1 MW. 2,772 of those solar DERs, which have a combined nameplate capacity of 42.5 MW, became participants in the DER Pilot. From the Pilot's inception through PY3, a total of 9,678 DERs have become Pilot participants while 7,154 other DERs have interconnected but not become participants in the Pilot. Overall, PPL Electric's DER Pilot showcases a successful model of integrating DERs in a manageable, scalable manner that benefits the Company, its customers, solar developers, and the Commonwealth.

Specifically, based on the data gathered through PY3, PPL Electric has calculated that the DER Pilot could reduce planned capital expenditure by approximately $18.7 million and operation and maintenance expenses by approximately $51.4 million.[1] By comparison, the total capital costs and operation and maintenance expenses associated with the DER Management device costs were approximately $12.3 million and $986,000, respectively. When considering the additional start-up costs associated with the DER Pilot, the total capital costs and operation and maintenance expenses were approximately $17 million and $3.7 million, respectively. Therefore, the DER Pilot has produced substantial benefits compared to its costs. The DER Pilot has improved the reliability and performance of the distribution system, increased DER hosting capacity, and facilitated the interconnection of more DERs, all the while reducing the Company's capital costs and expenses that would be passed onto customers. Furthermore, PPL Electric's continued learning and adaptations have allowed additional program savings related to the overall cost of the DER Management device installation and provisioning.

PPL Electric continues to evaluate methods to expand the benefits produced by DER management, particularly to adopt to higher levels of DER penetration in the future. The Company's analyses are detailed within 19 whitepapers and include the use cases set forth in the DER Pilot's Pilot Implementation Plan.[2] The continued analysis of current and potential application of active management and monitoring has been a critical component of the DER Pilot and will help develop and expand on ways to facilitate and encourage DER deployments, while maintaining and improving the safety, reliability, and adequacy of electric service.

For example, DER hosting capacity increases continue to help interconnection a greater number of DERs at a reduced cost to interconnection applicants. At the conclusion of PY3, hosting capacities for monitored, autonomous, and active

[1] The DER Pilot has increased hosting capacity by an estimated 98 MW. If that additional 98 MW were fully utilized as of March 21, 2025, it would have produced additional generation and reduced distribution and transmission losses valued at approximately $11.3 million.
[2] https://www.puc.pa.gov/pcdocs/1694930.pdf.

management were calculated to be 63 MW, 80 MW, and 98 MW respectively, demonstrating one of the key, incremental benefits of active management compared to relying solely on inverters' autonomous functions.

In addition, PPL Electric continues to expand the number of approved inverters that can be safely connected to and used with the Company's DER Management devices. As of March 21, 2025, PPL Electric's Approved Inverter List has 309 inverters from 18 different manufacturers, up from 241 inverters and 12 different manufacturers as of April 22, 2024. Also, inverters from 5 manufacturers are currently undergoing the review and approval processes. PPL Electric reviews and approves inverters expeditiously. Therefore, as new inverters come to market, PPL Electric can review and approve them for use so long as they meet the applicable requirements. Taken together, the high volume of DER installations and continued availability of many inverter models show that the Company is committed to facilitating DER interconnections.

PPL Electric's DER Pilot also showcases the significant benefits of active management in achieving dynamic grid optimization. Unlike autonomous systems that operate on predefined rules and have limited adaptability, active management of DERs facilitates real-time operational adjustments. This dynamic approach optimizes grid performance in response to changing conditions, enhancing grid reliability, safety, and affordability. Moreover, actively managed DERs boast scalability and flexibility because they are capable of being adjusted for growth without the need for extensive in person reprogramming or physical changes required by autonomous systems.

This active management strategy has yielded notable customer benefits within PPL Electric's Pilot. PPL Electric expects these benefits to grow as more actively managed DERs connect to the distribution system. Key to this success is the implementation of power factor management, which has resulted in shorter durations and lower magnitudes of voltage violations on feeders with actively managed DERs. As more actively managed DERs are incorporated, customer outcomes on these feeders improve in tandem, highlighting the effectiveness of PPL Electric's voltage management approach. Contrasting with the limitations of autonomous curves, which only react to local voltage conditions, PPL Electric's active management of the DERs optimizes all available resources. This improves power quality for customers with minimal impact on the ability for such customers to generate real power, underlining the additional benefits of active management in enhancing grid performance.

In sum, active management and monitoring of DERs is crucial as the proliferation of DER and electrification technologies continues. The ongoing application of DER monitoring and management not only effectively improves interconnection capacity but also plays a pivotal role in reducing both infrastructure and interconnection costs for customers. This forward-looking approach emphasizes PPL Electric's commitment to innovatively addressing the evolving needs of the energy grid and its users.

DER and Management Device Installations

Per Implementation Plan Section G.1.1 -The number of DERs Installed and the Number of DER Management Devices Installed

PPL Electric has enrolled 9,678 DER participants from the start of the DER Pilot through PY3. DER adoption continues to increase annually, beyond the limits of the Pilot. Under the Commission-approved Settlement establishing the Pilot, no more than 3,000 DER Management devices can be installed in a calendar year. PPL Electric hit that annual cap in 2023 and 2024. Any DERs placed in-service during the calendar year after the annual cap is hit are not enrolled in the Pilot and do not have DER Management devices installed for them.

- Control Group 1 (CG1)
  - PY3 participants: 342
  - Installed within the first 75 participating feeders
  - Does not include any Pilot DER assigned within the Active Management control group
- Control Group 2 (CG2)
  - PY3 participants: 0
  - Consists of the first 1,000 Pilot participants and includes participants within Control Group 1, until threshold has been achieved
  - In total there are 999 Pilot participants within Control Group 2, with 205 being also assigned within Control Group 1
- Active Management Group (AM)
  - PY3 participants: 2,429
  - All DER Pilot participants that have DER Management devices installed and can have their DERs actively managed
- Non-Pilot Participants or Grandfathered
  - PY3 installations: 1,204
  - No DER Management devices installed

Communications Methodology

At the DER Pilot's inception, PPL Electric utilized ConnectDER devices to monitor and actively manage DERs participating in the Pilot. PPL Electric added its Cellular Gateway devices in September 2023, expanding Pilot participation to include IEEE 2030.5-compliant devices. Before the addition of the Cellular Gateway devices, DERs' inverters that were only compatible with this communications standard were excluded from the Pilot.

A detailed list of Pilot participating DERs and initially programmed Volt-VAR Curves (VVC) is set forth in Appendix A.

DER Management Device Installations

From the DER Pilot's start through PY3, a total of 9,678 DER Management devices have been installed at participating DERs, representing slightly more than 100 MW of nameplate capacity. During PY3, a total of 2,789 DER Management devices were installed, as detailed within Table 1.

Table 1. DER Management Devices Installed per Year

	Year 1	Year 2	Year 3	Total
ConnectDER Generation 1 DER Management Device	1,197*	1	0	**1,198**
ConnectDER Bridge	2,769	2,688	1,936	**7,393**
Cellular Gateway	0	234	853	**1,087**
Total	**3,966**	**2,923**	**2,789**	**9,678**

*The total number of ConnectDER Generation 1 DER Management devices installed within PY1 has been updated to 1,197, as opposed to the 1,219 listed in the PY1 and PY2 Annual Reports. This update was made after the Company reconciled the data in its internal records and its Work Management Systems.

DER Management Pilot Participant Programming

Per Implementation Plan Section G.1.2 - A list of participating DERs that includes for each DER: (a) a unique customer identifier; (b) the nameplate capacity; (c) the initial settings established for that DER's smart inverter; and (d) the type of DER (e.g., solar, solar plus storage)

A full list of participating DERs, along with the applicable DER attributes and the assigned Volt/VAR curves, has been provided in Appendix A.

Autonomous DER Management Parameters

PPL Electric has created unique Volt-VAR Curves ("VVC") for each DER Pilot participant. These curves consider the influence of the transmission system, distance from the substation, and the observed variations in the customer's voltage. From the results of the VVC analysis, unique curve points are assigned, similar to those indicated within the sample curve, Figure 1, *infra*. These unique values correspond to the following:

- Points X1 - X6
    - Each of these values corresponds to specific per unit voltage values, progressing from low voltage (X1) to high voltage (X6).
    - These values represent the calculated transition points of the VVC.
- Points Y1 - Y6
    - Each of these values corresponds to the required reactive power output values of the inverter.
    - Note: the maximum and minimum inverter output is fixed at +/- 44%.

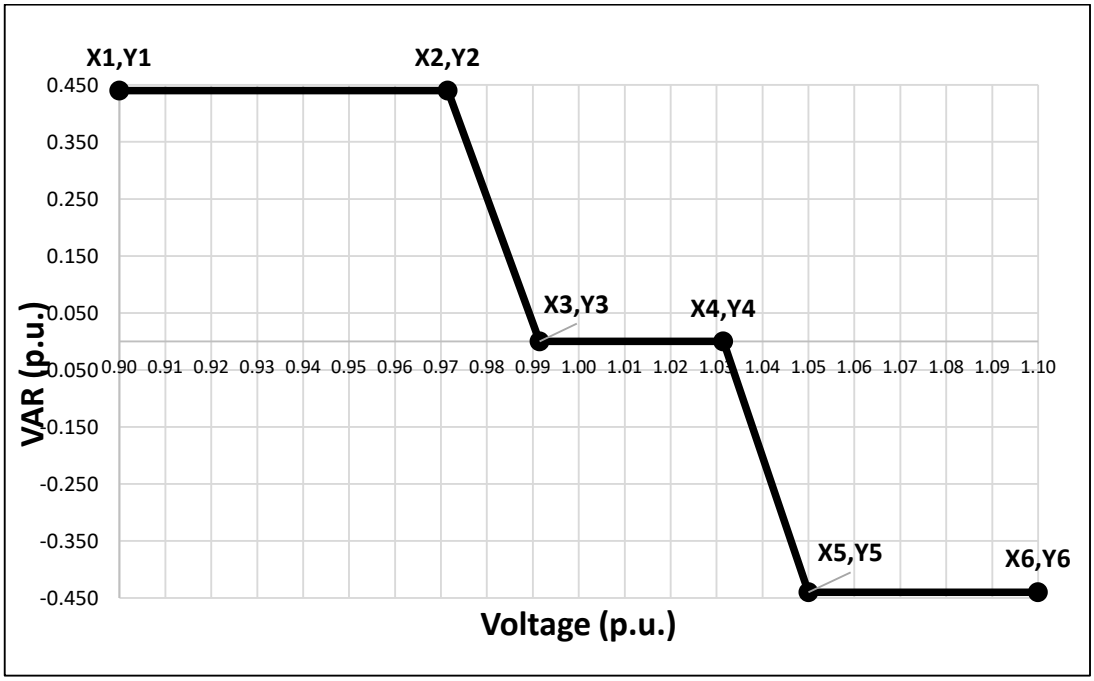

Figure 1. Sample Volt-VAR Curve (VVC)

Ride-Through Curve Parameters

All participating DERs are programmed with the latest approved standardized voltage and frequency ride-through parameters. Revisions to these settings, once initial programming has been completed, are only permitted for actively managed DERs. The latest revision of these parameters was approved in 2023. The actively managed DERs' inverters have had their ride-through curve parameters updated to the latest revision in order to improve their response to voltage and frequency variations.

DER Pilot participants in Control Groups 1 and 2 are only permitted to be programmed with the then-current ride through parameters at the time of initial programming. All non-Pilot participating DERs are not required to utilize PPL Electric-specific ride through settings, but they may be required to follow the minimum guidelines as detailed within PJM Guideline for Ride Through Performance of Distribution-Connected Generators[3] (2019).

Current PPL Electric Standard Ride-Through Curve Points

As noted previously, PPL Electric's current standard ride-through parameters were approved in 2023. The following tables detail those parameters.

Table 2. Current Standard Under Voltage Requirements

Under Voltage Requirements *Shall Ride Through* and *Shall Trip* curves are identical (overlapping) and defined in this table.		
Shall Trip Function	Voltage (p.u. of nominal voltage)	Time (sec)
UV1	0.88	2.1
UV2	0.5	0.6

[3] https://www.pjm.com/-/media/DotCom/planning/plan-standards/pjm-guideline-for-ride-through-performance.ashx

Table 3. Current Standard Over Voltage Requirements

Over Voltage Requirements *Shall Ride Through* and *Shall Trip* curves are identical (overlapping) and defined in this table.		
Shall Trip Function	Voltage (p.u. of nominal voltage)	Time (sec)
OV1	1.1	2.1
OV2	1.2	0.2

Table 4. Current Standard Under Frequency Requirements

Shall Trip – Under Frequency Requirements		
Shall Trip Function	Frequency (Hz)	Clearing Time (sec)
UF1	58.5	301
UF2	56.5	0.2

Table 5. Current Standard Over Frequency Requirements

Shall Trip – Over Frequency Requirements		
Shall Trip Function	Frequency (Hz)	Clearing Time (sec)
OF1	61.2	301
OF2	62	0.2

Legacy Ride-Through Parameters

As noted previously, because PPL Electric is not permitted to modify the ride-through settings of existing inverters within Control Groups 1 and 2, there are some systems which still utilize the legacy ride-through settings identified below. All such systems are marked accordingly in the "Legacy Ride Through" column in Appendix A.

Table 6. Legacy Under Voltage Requirements

Under Voltage Requirements *Shall Ride Through* and *Shall Trip* curves are identical (overlapping) and defined in this table.		
Shall Trip Function	Voltage (p.u. of nominal voltage)	Time (sec)
UV1	0.88	2.0
UV2	0.5	0.5

Table 7. Legacy Over Voltage Requirements

Over Voltage Requirements *Shall Ride Through* and *Shall Trip* curves are identical (overlapping) and defined in this table.		
Shall Trip Function	Voltage (p.u. of nominal voltage)	Time (sec)
OV1	1.1	2.0
OV2	1.2	0.16

Table 8. Legacy Under Frequency Requirements

Shall Trip – Under Frequency Requirements		
Shall Trip Function	Frequency (Hz)	Clearing Time (sec)
UF1	58.5	300
UF2	56.5	0.16

Table 9. Legacy Over Frequency Requirements

Shall Trip – Over Frequency Requirements		
Shall Trip Function	Frequency (Hz)	Clearing Time (sec)
OF1	61.2	300
OF2	62	0.16

Pilot Expenditures

Per Implementation Plan Section G.1.3 - Capital costs and expenses associated with the purchase, installation, ownership, and maintenance of DER management devices

The capital costs and expenses associated with the purchase, installation, ownership, and maintenance of the DER management devices utilized throughout the Pilot are presented in Tables 10 and 11, *infra*. These capital costs and expenses cover the start of the DER Pilot on January 1, 2021, through March 21, 2025.

Table 10. Pilot Total DER Management Device Purchase and Installation Costs

Purchase Costs	Pilot Total
ConnectDER Simple Collar	$ 98,559.60
ConnectDER Generation 1 DER Management Device	$ 856,535.34
ConnectDER Bridge Device	$ 4,842,744.21
Cellular Gateway	$ 1,231,241.75
Sub Total (Purchase)	***$ 7,029,080.90***
Installation Costs	
ConnectDER Simple Collar	$ 76,576.09
ConnectDER Generation 1 DER Management Device	$ 300,598.68
ConnectDER Bridge Device	$ 3,847,150.80
Cellular Gateway	$ 1,065,784.07
Sub Total (Installation)	***$ 5,290,109.64***
Total Capital Costs	**$ 12,319,190.54**

Table 11. Total Maintenance Costs

Maintenance Costs	Pilot Total
ConnectDER Simple Collar	$ 84.00
ConnectDER Generation 1 DER Management Device	$ 195,929.98
ConnectDER Bridge Device	$ 500,122.25
Cellular Gateway	$ 62,903.39
IT	$ 227,001.26
Total Maintenance (Expense)	**$ 986,040.88**

The average per unit cost of each DER Management device has been detailed within Table 12. These costs consider the total material, labor (installation and troubleshooting), and maintenance costs, divided by the total number of the respective devices currently installed, as detailed within Table 1.

Table 12. Average Total Cost per Unit by Device Type (Materials, Labor, Maintenance)

Device Type	Average Total Cost Per Unit
ConnectDER Generation 1 DER Management Device	$ 1,152.88
ConnectDER Bridge Device	$ 1,265.67
Cellular Gateway	$ 2,194.49

PPL Electric notes that the average per unit cost of the ConnectDER Generation 1 device has decreased compared to the PY2 Annual Report, while the average per unit cost of the Bridge and Cellular Gateway has increased. Those increases were driven by higher labor costs for installing the Bridge and Cellular Gateway devices in PY3. PPL Electric is actively investigating potential ways to reduce those labor costs, including a decreased reliance on contractors to install the DER Management devices.

Additionally, the Company is phasing out the current generation of the Bridge and Cellular Gateway devices later in 2025. The new versions of the devices will be significantly cheaper to procure. Specifically, the per-unit procurement cost for the new Bridge device will likely be at least 40% cheaper, while the per-unit procurement cost of the new Cellular Gateway device will likely be at least 60% cheaper. By moving to these new and less expensive versions of the devices, PPL Electric will significantly reduce the procurement costs for the devices.

DER Management Device Intervention

Per Implementation Plan Section G.1.4 - Number of times, locations, and duration for active management

Through the DER Pilot, PPL Electric Pilot participants, within the active management control group, have been able to be centrally managed, via the Advanced Distribution Management System's ("ADMS") Load and Voltage Management ("LVM") module. In addition to being centrally managed, the programmed settings of a subset of these participants have also been able to be updated, as indicated within Table 13.

Table 13. Grid Support Function - Total Event Counts, by Pilot Year

	Year 1 (Jan 21 - Mar 23)	Year 2 (Mar 23 – Mar 24)	Year 3 (Mar 24 – Mar 25)
Volt-VAR Curve Overrides	0	12	0
Power Factor Setting Changes	768	221,394	298,391
Ride-through Setting Changes	0	4,138	0
Remote On/Off	0	0	0
Volt-Watt Curve Overrides (where applicable)	0	0	0

The year-over-year increase in the number of power factor management events can be attributed to: (1) the continued refinement of PPL Electric's ADMS and Distributed Energy Resource Management System ("DERMS"); and (2) an increase in the number of actively managed DERs. Appendix B details the average duration of each power factor adjustment event, by distribution feeder, with the total number of events identified within Table 13 above. Further, each indicated event accounts for all actively managed DERs within an event. This results in potential variances between the total number of events listed within Table 13 and Appendix B.

Currently, in the Pilot's Active Management Group, each participant has a maximum fixed power factor duration, prior to restoring its autonomous functionality. For a large portion of these DERs, the maximum duration has been established at 10 hours. During PY3, 298,391 events occurred, of which 94,670 returned the DERs to unity power factor, restoring

autonomous functionality. The return to unity power factor is not intended to provide grid benefits; rather, it acts as a failsafe to ensure customers do not experience excessive generation curtailment if the DER Management device were to fail to return the system to Volt/VAR management mode as programmed. A-10-hour reset time was selected to restore the inverter to unity power factor after a full day of daylight operation. A power factor management event occurring as a result of this function does not indicate that the device failed, but rather that PPL Electric's failsafe to protect customers is working as intended.

Observed DER Management Benefits

PPL Electric's DER Pilot continues to showcase the significant benefits of the integration of autonomous DER functionality and centralized active management, providing dynamic grid optimization. Throughout the DER Pilot, PPL Electric has increased the total number of DERs that can positively impact distribution system voltage and power factor. This dynamic approach optimizes grid performance in response to changing conditions, cost-effectively enhancing electric reliability, safety, and power adequacy. As a result, the Pilot has yielded notable customer benefits that are anticipated to continue, as more DER Management devices are interconnected with the distribution system. With these additional devices, opportunities to leverage all participating DERs to further address power quality issues will be possible. Continued implementation of power factor management is a key to future DER Management success and will result in a reduction in instances, durations, and severity of voltage violations.

Autonomous Benefits

The use of autonomous VVC has enabled participating DERs to help maintain PPL Electric's distribution system voltage within mandated voltage ranges.[4] As noted previously, within the description of Figure 1, each DER begins to adjust its kVAR output- once the measured voltage extends outside of the deadband range (X3 – X4) according to the programmed VVC. Each inverter's influence on overall distribution system voltage is dependent on the programmed VVC and its ability to restore system voltage within the deadband area. Through these efforts, each DER's programmed VVC is tailored to its location in order to provide the maximum support necessary without sacrificing DER output.

Validating autonomous benefits is more difficult to quantify than those detailed within active management interventions. This is due to the instantaneous influence occurring via the programmed VVCs, versus the centralized commands issued by PPL Electric to actively managed DERs. Near real time autonomous response can occur via the observed voltage at the DER and the anticipated location within each VVC. The impact of each inverter's output can be assessed against the observed feeder voltage violations by utilizing the Company's smart meter data.

Active Management Benefits

Per Implementation Plan Section G.1.5 - Grid benefits achieved for each instance of active management

PPL Electric's DER Pilot continues to showcase the significant benefits of active management in achieving dynamic grid optimization. Unlike autonomous systems, operating on predefined rules, DER active management utilizes a centralized overview of a feeder to facilitate near real-time operational adjustments, of inverter outputs. Active management swiftly responds to larger events, beyond the capabilities of an autonomous DERs, through a centralized overview and

[4] *See* 52 Pa. Code § 57.14.

simulation of potential power factor adjustment iterations before enacting them. As a result, PPL Electric can modify DER power factors to respond to a global requirement, providing a coordinated response to an event.

Through PPL Electric's DER Pilot, the Company has defined the parameters of grid benefits for each instance of active management intervention. As with the results detailed in the PY2 Annual Report, the Company has seen continued improvements in system voltage event resolution. While not all violation events are fully resolved, the use of actively managed DERs continues to help reduce the number, duration, and severity of voltage violations. Continued growth in actively managed DERs will support a greater number of voltage violations being resolved and provide additional support towards resolution of events that were not previously able to be resolved.

The Company defines "grid benefits achieved" for real-time constraint mitigation as the change in the number or severity of voltage violations present on the system in the time intervals before and after the active management of one or more DERs. The intent is to capture observed changes which result directly from the influence of an active management on a per-event basis. Voltage is also influenced by a multitude of factors that can contribute to each customer's observed voltage within an interval. The variability of these factors can mask the attribution of the positive impact of actively managed DER. This is particularly true within feeders and substations whose actively managed DERs are only a small portion of the total DERs present. As noted previously, isolating the portion of observed voltage change attributed to each specific actively managed DER is not currently possible at scale.

Further, the change in customer observed voltage violations, for each active management event, is calculated by evaluating the reported average smart meter voltages for the reporting interval immediately preceding and immediately following the active management event. Each active management event may include one or more DERs supplied from the same distribution bus. Also, the total number of events may differ between the number of DER power factor settings changes and the identified violations indicated elsewhere within this report. Additionally, PPL Electric's ADMS/DERMS estimates the number of voltage violations resolved, due to the active management of each DER. A description of these calculations and the results can be found within the active management operational descriptions section of this report. The complete table of grid benefits achieved for each instance of active management has been compiled as Appendix C.

Manually modeling the specific effects of each active management event is impractical, due to the volume and scale of analysis that would be required. However, several specific events have had comprehensive studies completed. The results of these studies are detailed within the Use Case section of the report below.

Active management has established the ability to incorporate telemetered DER data and leverage each participating DER's output into future control system strategies, yielding notable customer benefits. Through continued DER penetration growth, these benefits are anticipated to continue to grow. This will enable an increase in the opportunity to leverage all participating DERs to contribute to resolving voltage issues, power quality issues, or both on the grid. As noted previously, a key observation to the continued successful implementation of centralized DER output management is a reduction in the number, duration, and severity of voltage violations on feeders with actively managed DERs. As more actively managed DER are incorporated, it is anticipated that these results will continue to improve, highlighting the effectiveness of PPL Electric's centralized voltage management approach.

Contrasting with the limitations of autonomous curves, which only react to local voltage conditions, PPL Electric's active management of DER optimizes all available resources, locally and globally. This improves power quality for customers with minimal impact on their ability to generate real power, underlining the additional benefits of active management in enhancing grid performance.

Net DER Generation Impact Due to Active Management

Per Implementation Plan Section G.1.6 - Net generation gain or loss due to active management

PPL Electric has created a detailed report capturing the net generation loss or gain due to PPL Electric's active management of grid support functions, for each device intervention. That report can be found in Appendix D. The total active power generation reduction identified, as a result of these active management events, continues to represent a very small portion of overall system generation capabilities.

Specifically, on average, actively managed DERs experienced a net generation reduction of 0.099465kWh per event, totaling 29,679 kWh across 298,391 events.

Distribution Capital Investment Avoidance Due to DER Hosting Capacity

Among other benefits, PPL Electric's DER Pilot helps avoid distribution system upgrades by increasing distribution circuits' hosting capacity. Based on the data collected through PY3, the Pilot has increased available DER hosting capacity by 98 MW.

To derive that amount, PPL Electric utilizes a nodal analysis approach, whereby the Company evaluates the maximum amount of DERs that can be added to each feeder node without triggering any violation criterion (i.e., device overload, voltage violation, potential islanding etc.). The results have been compiled within Appendix E.

In addition to the detailed nodal DER hosting capacity, the maximum DERs permitted to interconnect on each substation's 12 kV bus has also been compiled. These indicated values, within this second portion of the analysis, represent the point at which reverse power flow occurs on the 12 kV bus or violates load and voltage criteria. These values are also contained within Appendix E, under Columns F and G (Nameplate – Max Hosting Capacity (kW) and Monitored – Max Hosting Capacity (kW)).

PPL Electric has also calculated an estimated maximum DER hosting capacity for nameplate and monitored scenarios. This total was calculated by identifying the largest amount of DERs that could be accommodated on each substation transformer bus, when supplying more than one feeder, and adding these values for all non-parallelled substation buses. These buses are generally independent of each other, as tie switches, and breakers, are normally open. Thus, the calculated values represent a reasonable approximation of the system-level DER hosting capacity, assuming no constraints are observed within the transmission system.

An overview of the hosting capacity results is provided in Table 14. As seen in that table, active management continues to prove beneficial and reduce or avoid capital investments in the distribution system.

Table 14. DER Hosting Capacity Results, by Reporting Year (in MW)

	Year 1	Year 2	Year 3
Nameplate vs Monitored	6.6	18.1	63
Monitored vs Autonomous	1.4	5.7	17
Autonomous vs Actively Managed	1.0	4.9	18
Monitored vs Actively Managed	9.0	28.8	35

Capital Investment Avoidance Attributed to Increased DER Hosting Capacity - Monitoring

Per Implementation Plan Section G.1.7 - Distribution system upgrades avoided due to increased hosting capacity attributed to monitoring

PPL Electric is required to develop a report which compares the computed circuit hosting capacity when all DERs are evaluated at nameplate kW only versus the hosting capacity of each circuit with actual kW output, gained via monitoring, while keeping Grandfathered DERs at nameplate kW. Results indicate that the availability and use of actual DER system production data results in a noticeable increase in a circuit's calculated hosting capacity in most cases. Cost-effective increases in hosting capacity are critical to enabling the renewable energy transition by reducing and avoiding costs for future interconnections of renewable resources.

As of the end of PY3, PPL Electric's ability to monitor DERs has resulted in an increase of 63 MW of DER hosting capacity.

Capital Investment Avoidance Attributed to DER Hosting Capacity – Autonomous Functions

Per Implementation Plan Section G.1.8 - Distribution system upgrades avoided due to increased hosting capacity attributed to autonomous grid support functions

PPL Electric has developed a report which compares the computed circuit hosting capacity with actual kW gained via monitoring only versus the scenario where those DERs are equipped with autonomous grid support functions, while keeping grandfathered DERs at nameplate kW. Autonomous functions provide additional benefits in the form of improved hosting capacity by allowing DERs to respond to local voltages to help mitigate high or low voltage constraints.

As of the end of PY3, the utilization of PPL Electric-calculated VVCs has resulted in an estimated 17 MW of DER hosting capacity.

Capital Investment Avoidance Attributed to DER Hosting Capacity – Active Management Functions

Per Implementation Plan Section G.1.9 - Distribution system upgrades avoided due to increased hosting capacity attributed to active management

PPL Electric has developed a report which compares the computed circuit hosting capacity when all DERs are evaluated at the nameplate kW only, without any monitoring or active management, versus the hosting capacity of each circuit with actual kW output gained via active management, while keeping grandfathered DERs at nameplate kW. Active management shows additional improvements in feeder hosting capacity when compared to autonomous only scenarios. This results from the ability of active management to utilize DER to respond to voltage violations holistically, rather than relying on DERs to adjust themselves based on local measurements.

As of the end of PY3, PPL Electric's ability to actively manage DERs has increased DER hosting capacity by 18 MW when compared to autonomous functions and by 35 MW when compared to monitored results.

Reliability Improvements

Per Implementation Plan Section G.1.10 - System operation comparisons of circuits under autonomous inverter grid support functions versus active management

PPL Electric has compiled customer meter voltage data and has developed observations pertaining to customer meter voltage performance between DER Pilot participants and non-participants. The non-participants have been identified as grandfathered ("GF"), whereas Pilot participants are classified further as Control Group 1 ("CG1"), Control Group 2 ("CG2"), and Active Management Group ("AM"). Through these initial observations, the Company has developed a comparison of customer voltage between each DER control group at the customer point-of-interconnection. PPL Electric completed a further comparison of all customer meter data between feeders with actively managed DERs versus those with CG1 DERs. Within the feeder comparison, GF DERs may also exist.

PPL Electric's voltage performance metrics have been designed to improve overall understanding of distribution system voltage performance, while closely following industry established reliability practices. In particular, PPL Electric based its voltage metrics on System Average Interruption Frequency Index ("SAIFI") and System Average Interruption Duration Index ("SAIDI"). While SAIFI and SAIDI are outage focused, the Company utilized these standardized metrics to create its own voltage metrics: System Average Voltage Violation Frequency Index ("SAVVFI") and System Average Voltage Violation Duration Index ("SAVVDI"). The calculation of these metrics utilizes the following datapoints:

> SAVVFI = (Total number of voltage violation events experienced by all customers in a set) / (total number of customers in the set)
> SAVVDI = (Total duration in minutes of voltage violation events experienced by a set of customers) / (total number of customers in the set)

In addition to the frequency (SAVVFI) and duration (SAVVDI) metrics previously detailed, PPL Electric also developed additional metrics to quantify the severity of voltage violations observed within each control group, (non) pilot participant. Within this context, a voltage violation's severity is the relative difference between the measured customer meter voltage and the permissible voltage range, per the Commission's regulations (0.95 to 1.05 per unit).[5]

For DER Point of Interconnection ("POI") analysis, SAVVDI, SAVVFI, and voltage severity values have been calculated separately for the GF, CG1, CG2, and AM groups. Pilot participants identified as CG12, who were assigned to both CG1 and CG2 control groups, will be included within CG1 and CG2 analysis. All calculations within this analysis only consider daylight hours.

DER POI SAVVDI and SAVVFI Historical Trends

Prior to completing an examination of the DER POI voltage violation data, the Company reviewed historical voltage violation trends that had been present before and the participating DER had been installed. The data within Figure 3 shows the SAVVDI and SAVVFI trends, at customer metering locations, before any Pilot DERs were interconnected. Pilot participants, as well as grandfathered DERs, interconnected by December 31, 2024, encompass the dataset for the results presented in Figure 2. Within these results, it is evident that a number of voltage violations were present in each

[5] *See* 52 Pa. Code § 57.14.

Pilot group (CG1, CG2, and AM) prior to any DER Management devices being installed. The use of these periods can be utilized as pre-Pilot baselines and used as a measure of comparison going forward.

Similarly, within this analysis, the DERs identified as grandfathered are those that have been installed after the Pilot commenced but are non-Pilot participants. Continued analysis of these DER, in the future, can also consider this data set as a pre-installation baseline, like the aforementioned Pilot participants. The remaining grandfathered DERs, which were installed prior to the Pilot, have been excluded from the remaining analysis detailed below.

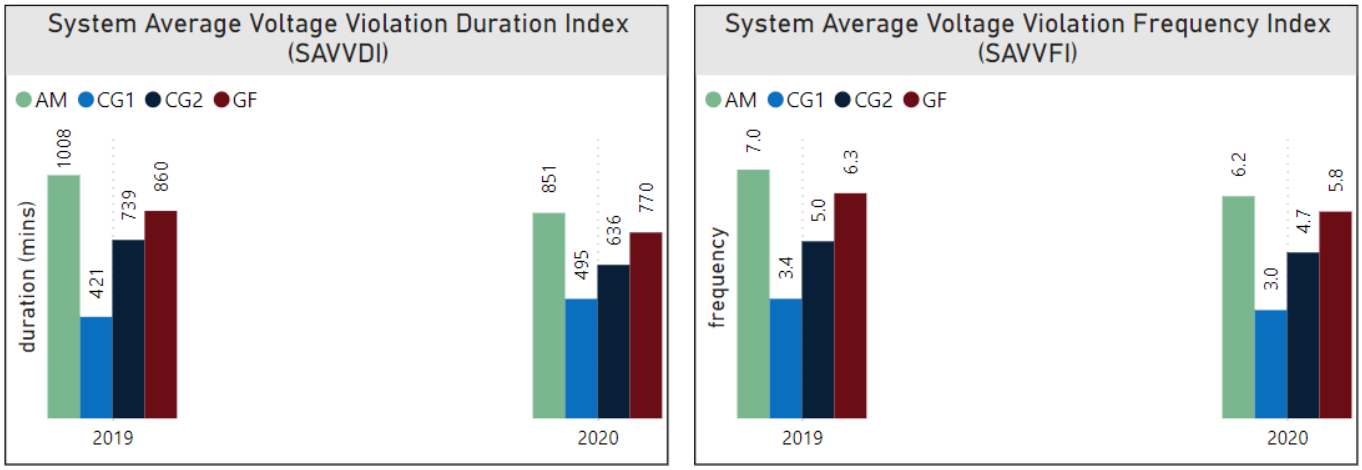

Figure 2. DER Customer Historical SAVVFI & SAVVDI by Calendar Year

Figure 3 and Figure 4 present a continuation of the trends depicted in Figure 2, as the DER Pilot commenced. However, it is important to recognize that voltage violation data for the GF, CG1, CG2, and AM groups starts being collected for each customer location from the date that the DER is connected and (in the case of AM and control group DERs), programmed with a VVC. As a result, the corresponding SAVVDI and SAVVFI results have an upward trend, as additional customer meter data is included within the analysis. The Pilot participating DERs (CG1, CG2, and AM groups) have a smaller impact on the SAVVDI and SAVVFI calculations, while the non-Pilot participating GF DERs have had a significant increase in both SAVVDI and SAVVFI. There continues to be significant increases in the number of Pilot participating DERs within the AM group, with the ability to positively impact voltage violations. DERs assigned within the AM group function autonomously via their uniquely assigned VVCs until ADMS/DERMS intervention.

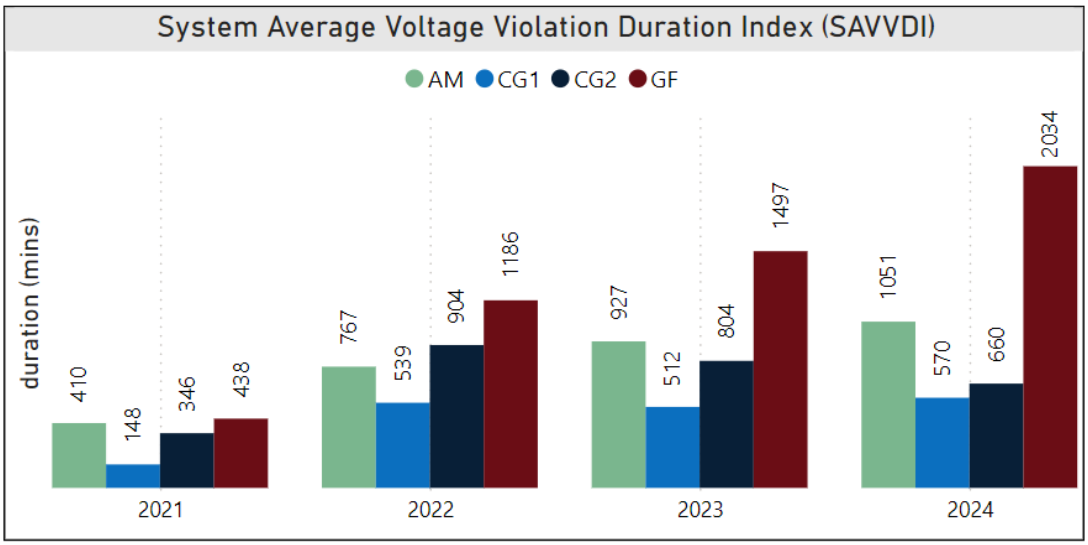

Figure 3. DER Customer SAVVDI with Fixed Customer Set by Calendar Year

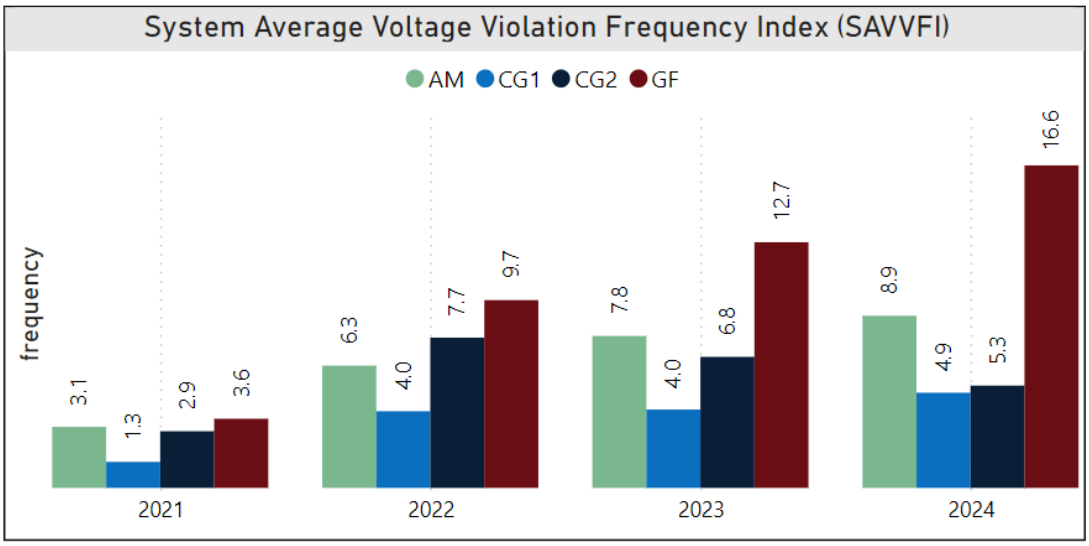

Figure 4. DER Customer SAVVFI with Fixed Customer Set by Calendar Year

On its own, the voltage data at the DER customer location does not paint a complete picture of the impact of VVCs and active management on customer voltages and power quality. To capture the full impact, the voltages at all customer locations, both those with and those without DERs, must be considered. Both PPL Electric's VVC design process and the execution of active management consider both the local DER customer voltage as well as the impacts to voltage elsewhere on the system. The existence of CG1 provides a more direct way of evaluating the impact of active management capabilities on customer voltage violations. In Figures 9 and 10 later in this report, SAVVFI and SAVVDI have been calculated for all customers on CG1 feeders as well as for all customers on feeders with actively managed DERs. Because this data considers each meter on a given set of feeders (CG1 or AM), low sample size is not an issue, even for relatively smaller numbers of actively managed DERs because those DERs are spread across many different feeders and, consequently, a high volume of voltage measurement datapoints.

DER POI SAVVDI and SAVVFI Throughout Pilot

PPL Electric also completed an analysis that directly compares voltage trends and performance of non-Pilot participating DERs installed before the Pilot started (assigned within the grandfathered control group) versus Pilot participating DERs (assigned within CG1, CG2 and AM groups). Similar to the previous analysis, smart meter voltage data, for customers within each dataset, was collected and assessed. An overview of the modifications to the previous analysis includes:

1. Inclusion of pre-Pilot DERs, within the GF group, i.e., placed in-service to the January 1, 2021 start of the Pilot.
2. Inclusion of all Pilot participating DERs (CG1, CG2, and AM groups).

Note: The number of Pilot participants continued to grow throughout this analysis, whereas the number of GF group members was constant.

In the first year of the DER Pilot, the number of Pilot participants was relatively small. Due to the initial small sample set, the 2021 results are significantly lower than subsequent years and may be excluded in the development of any long-term trend analysis. Additionally, no DERs were assigned to the AM group in 2021. After Q2 2022, the AM group's size and ability to influence the distribution system voltage grew significantly, as illustrated within Figure 5 and Figure 6.

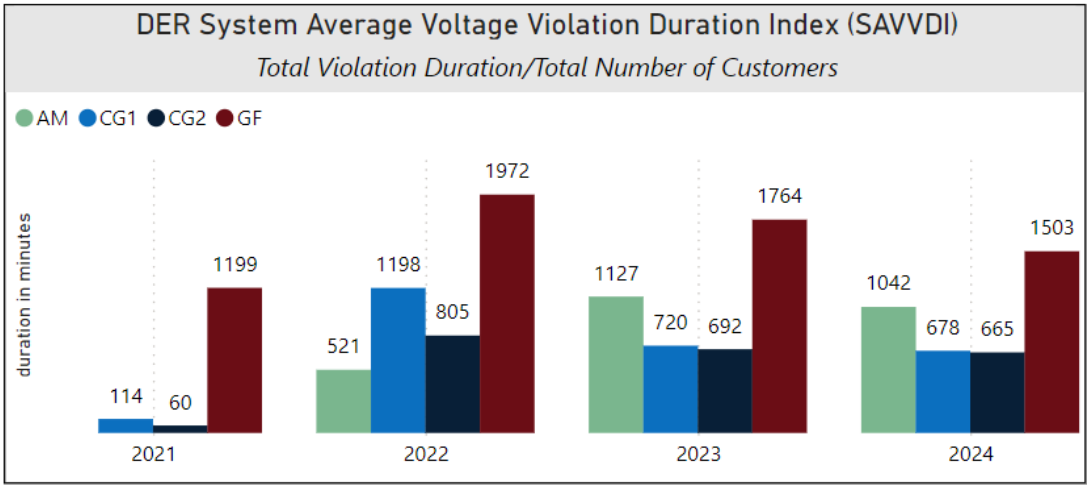

Figure 5. DER Customer SAVVDI Results by Calendar Year

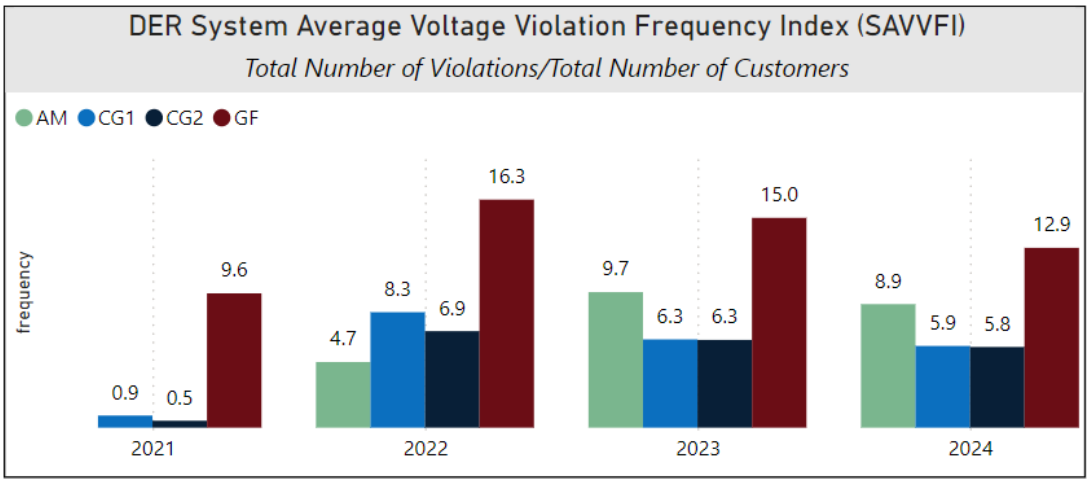

Figure 6. DER Customer SAVVFI Results by Calendar Year

DER POI Voltage Violation Severity

PPL Electric has continued to expand on its SAVVDI and SAVVFI analysis by adding a metric depicting the voltage violation severity, as a percentage, at the POI. The compilation of this data is limited to daylight hours and details the number of customer meter readings within each depicted percentage band. By compiling the metered data, voltage violations have been observed to occur less at Pilot participating customer meters, than non-participating meters. Additionally, the overall recorded voltage violations represent an extremely small portion of customer meter readings for Pilot and non-Pilot participants.

The compilation of these results is set forth in Figure 7.

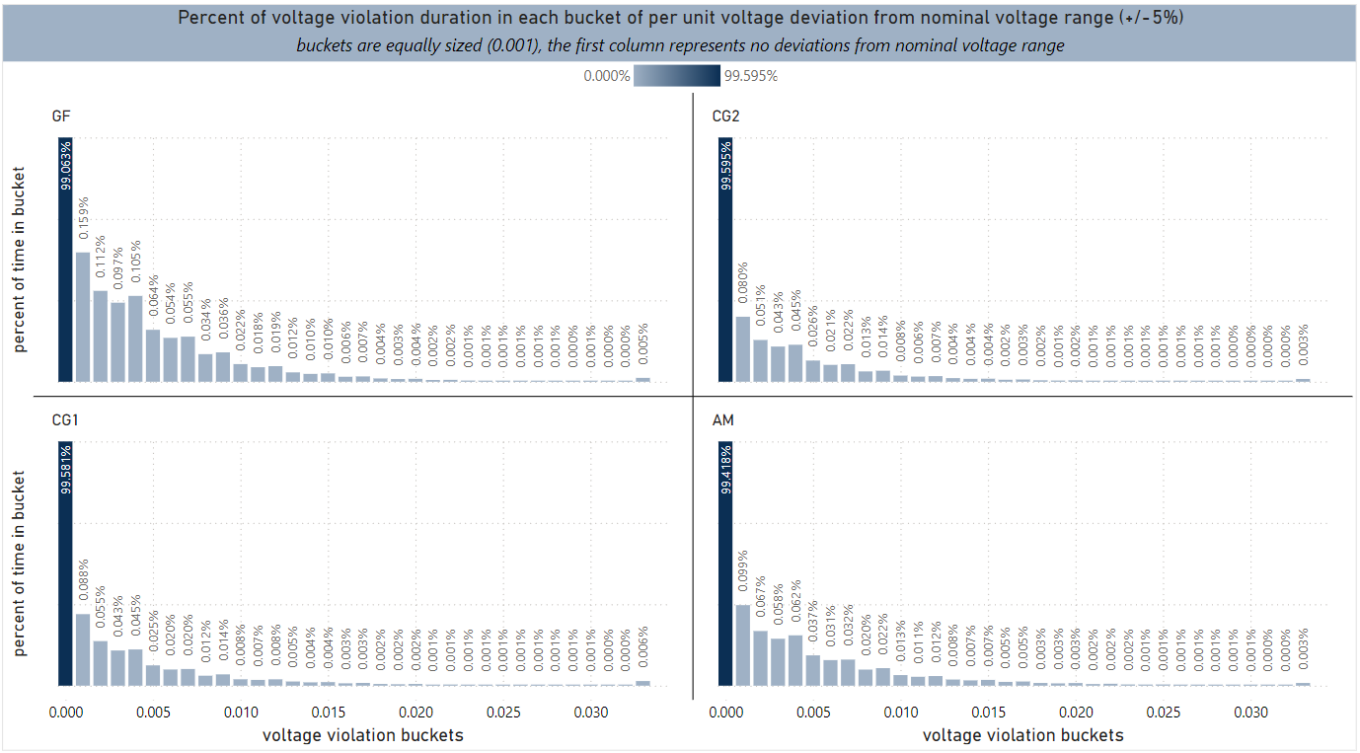

Figure 7. Voltage Severity Results by Pilot Group

Presenting the voltage violation severity results in a different form, Figure 8 excludes the customer meter periods without any voltage violations. The remaining data points have been converted to percentages. Through this revision of the data presentation, the cumulative number of periods in which a customer's voltage has fallen within each area of violation severity have been accumulated as a percentage of the total voltage violations observed. Non-pilot participating DERs (GF) tend to have higher voltage violation severities, for a larger number of periods, than Pilot participants (CG1, CG2, and AM). Accordingly, participation in the DER Pilot appears to have reduced the overall severity of voltage violations.

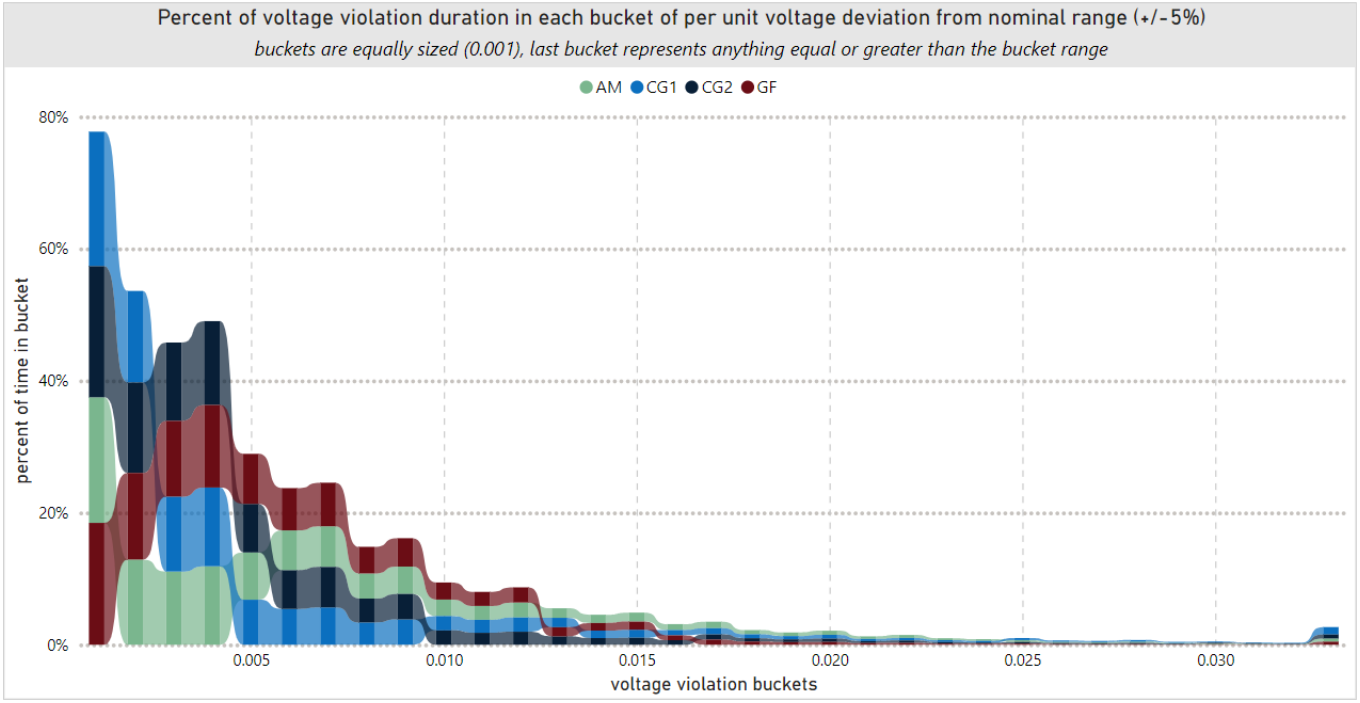

Figure 8. Voltage Severity Comparative Results by Pilot Group, Y-axis is stacked by size from smallest to largest percentage

From the analysis presented within Figure 7Figure 7 and Figure 8Figure 8, participation in the DER Pilot has helped reduce voltage violation severity, when compared against non-Pilot participating DERs. As non-Pilot participating DERs are most likely present on all feeders with Pilot participating DERs, the impact of Pilot participation may be potentially masked by the influence of the non-Pilot participating DERs.

Pilot Feeder SAVVDI and SAVVFI - Historical Trends

While customer meter voltage data, on its own, indicates the performance of each DER (participants and non-participants of the Pilot alike), such data does not fully encompass the voltage performance throughout the supplying feeder. Improving the overall understanding requires examining the DER penetration rate and all other parameters potentially influencing the feeder's overall voltage performance. When accounting for the DER penetration rate, the Company's data shows that DERs participating in the Pilot can improve the feeder's overall voltage performance. Further, the inclusion of those components reveals the influence and effectiveness of uniquely assigned VVCs and active management of DERs.

PPL Electric collected customer meter data to demonstrate the improvements of SAVVFI and SAVVDI performance on feeders in the DER Pilot. The data was parsed into AM and CG1 feeders. The annual SAVVFI and SAVVDI calculations are presented within Figure 9 and Figure 10. Unlike the previous analysis iterations, the data presented includes all Pilot feeders, from pre-Pilot implementation through to the end of 2024. As noted previously, DER adoption has continued to increase throughout the Pilot's duration. Through this increase, participation within the DER Pilot has increased to the maximum annual threshold from 2023 onward. With the increase in Pilot participation, the positive impact of VVCs and active management have demonstrated their influence in resisting voltage variations, as observed within the SAVVDI and SAVVFI calculations presented in Figure 9 and Figure 10 below.

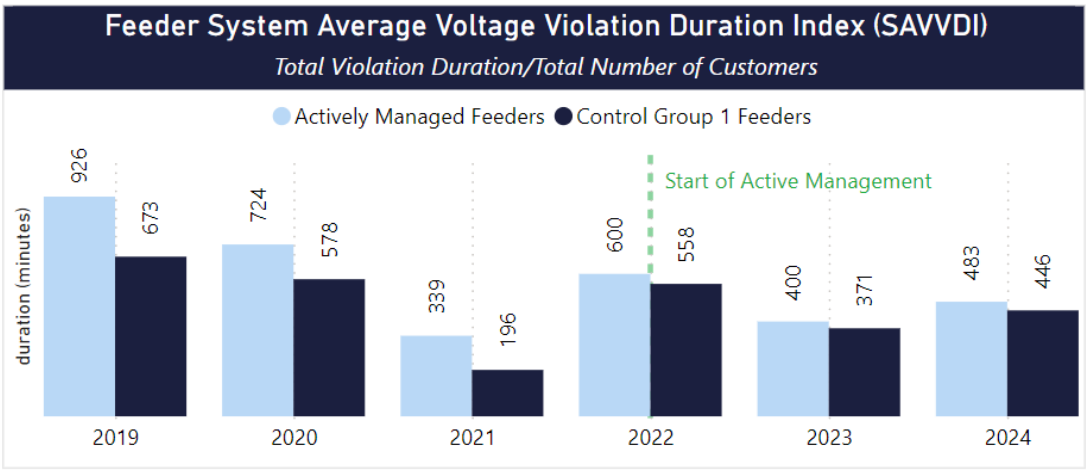

Figure 9. Feeder-Level SAVVDI Comparison Results by Calendar Year

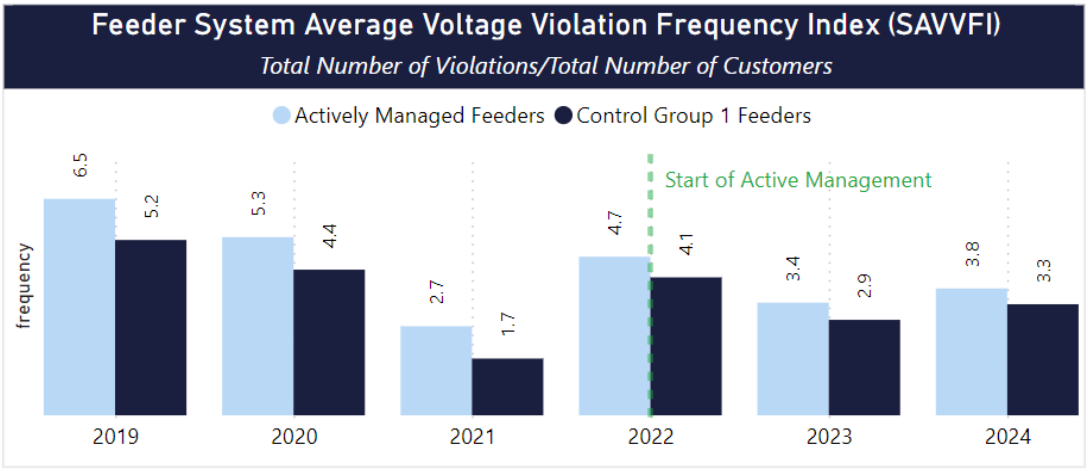

Figure 10. Feeder-Level SAVVFI Comparison Results by Calendar Year

In summary, Figure 9 and Figure 10 illustrate SAVVDI and SAVVFI for each feeder group and the incremental improvements seen, starting prior to the-Pilot's commencement (2019-2020) through observed DER penetration increases (2023 onwards). Figure 11 is an extension of Figure 9 and Figure 10 and demonstrates the difference within the SAVVDI and SAVVFI calculations between the two feeder groups, throughout the review period. From these three figures, the average system voltage violation has reduced more for actively managed feeders than it has for the CG1 feeders, following the commencement of DER active management in 2022. This highlights the anticipated benefits of active management in maintaining system voltage.

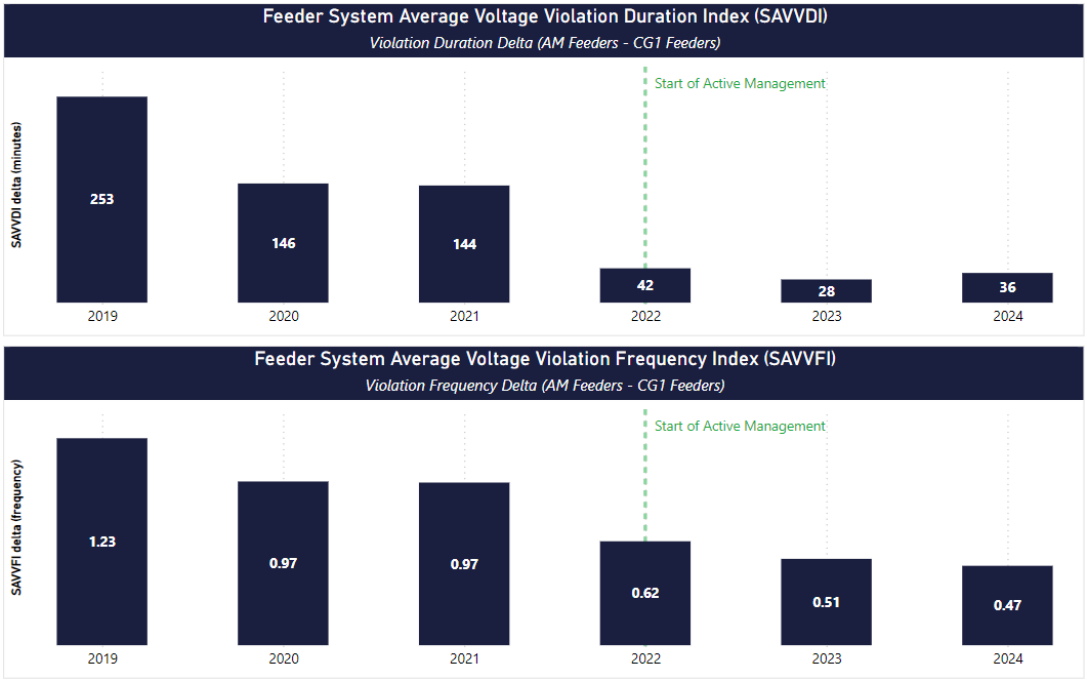

Figure 11. Feeder- SAVVDI & SAVVFI Comparison By Control Method by Calendar Year

Feeder Voltage Violation Severity

As a continuation of the SAVVDI and SAVVFI calculations above, calculating voltage violation severity at a feeder level provides a more significant comparison between CG1 feeders and those with DERs that can be actively managed. A review of the impact of autonomous only feeders (CG1) versus autonomous and AM illustrates the cumulative impact of integrating both Pilot management types, as seen within Figure 12. While CG1 feeders demonstrate the benefit of autonomous functions, AM feeders demonstrate the added benefit of active management.

As noted previously, through the inclusion of each of these feeder categories, from the Pilot's inception forward, the total nameplate capacity of DERs has continued to increase. Further, DER installations continue to increase on the AM feeders at a larger rate than observed amongst the 75 feeders comprising CG1. Non-Pilot participating DERs continue to be interconnected and disbursed throughout PPL Electric's distribution system, potentially influencing the results of both examined feeder categories.

As denoted within Figure 12, prior to the start of active management events in 2022, customers on feeders with actively managed DERs experienced a relatively lower incidence of the most severe voltage violations when compared to their peers on CG1 feeders. This gap widened by the end of 2023 due to the number of actively managed DERs and active management events significantly increasing. Although this gap narrowed in 2024, PPL Electric's Pilot data has shown that active management can have a clear impact on customer power quality.

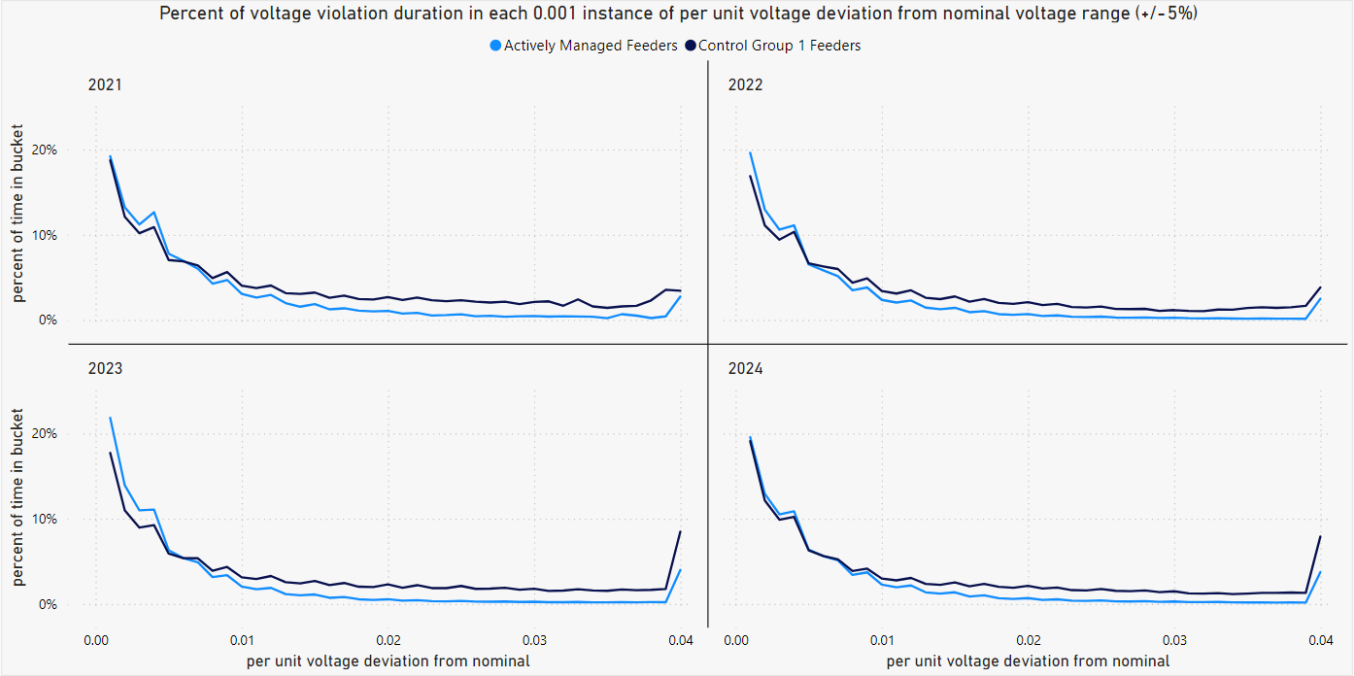

Figure 12. Feeder Level Voltage Severity Results Comparison

Voltage Violation Conclusions

Key takeaways from the comprehensive review of the figures in this section and their associated explanations are

1. **Trend of Shorter and Less Frequent Violations:** The Grandfathered Group has longer and more frequent voltage violations than Control Group 1, Control Group 2, and the Active Management Group. The trend of shorter and less frequent voltage violations for the latter three groups demonstrates that the DER Pilot is improving grid conditions.

2. **Historical Challenges in Actively Managed Feeders:** Feeders with actively managed DER historically faced a higher frequency of voltage violations, compared to those in CG1. However, the disparity in violation frequency between these groups has started to decrease beginning in 2022, showcasing how actively managing the DERs has gradually improved the feeders' performance.

3. **Response vs. Prevention:** PPL Electric's systems, including ADMS/DERMS, are configured more towards responding to existing voltage violations, rather than preventing them. This reactive approach results in less pronounced impacts on violation frequency, as interventions are primarily aimed at resolving the current sustained issues or preventing a recurrence within the same day. However, with DER management, the potential exists for significant enhancements in how voltage violations are managed through advancements in operational forecasting. With better predictive capabilities, it may become feasible to proactively manage and reduce the frequency of voltage violations before they occur, shifting from a reactive to a preventative management style.

4. **Quantifying Severity:** The development of new metrics to understand the severity of voltage violations adds another layer of depth to grid management. These metrics help quantify the delta between the permissible

range and the voltage measured, providing a clearer picture of the feeder's health and the effectiveness of voltage regulation strategies.

5. **Understanding Impact Over Time:** The analysis of severity across different times and conditions (such as daylight time intervals) helps in understanding the dynamic nature of voltage violations and the operational effectiveness of DER management across different scenarios.

Operational Efficiency Improvements Attributed to Active Management

Active management commands are communicated to the required devices via PPL Electric's ADMS and its accompanying LVM module. Through LVM, several scenarios are simulated, based on the incoming SCADA telemetry and customer meter data, to assess the needs of the distribution system. The resulting LVM solution is an optimally selected scenario and specifies the number of actively managed DERs to be included. Through the execution of these scenarios, a portion of the reported voltage violations is anticipated to be resolved.

Further analysis of these resolutions has led to the development of a metric indicating the number of potential technician site visits reduced, due to the resolution of voltage violations. Within each LVM plan period, a portion of impacted customers is anticipated to have their voltage violations resolved. With this, the number of customers with at least one voltage violation resolved, within an LVM plan period, is multiplied by the completion rate of LVM plans, which is currently 84.3%. The completion of an LVM plan includes the initiation and resolution of planned actions. Customer count is used rather than violation count to avoid counting multiple resolutions for a single customer as multiple truck rolls, and because not all resolutions are directly attributable to active management.

The completion rate is then multiplied by 75%, which is the frequency that PPL Electric deploys a truck and personnel in response to a voltage violation complaint based on the Company's power service problem ("PSP") data. The resulting figure is then multiplied by the cost PPL Electric incurs per truck roll to resolve a voltage violation. This provides an estimate of the overall cost effectiveness of active management in identifying, mitigating, and resolving voltage violations.

Table 15. Avoided Truck Roll Cost, per year, Attributed to DER Management Influence

Year	Truck Roll Rate	Voltage Violations that could have resulted in Truck Rolls	Total Cost to Respond to Voltage Violations that were Avoided
2022	$711	796	$565,956.00
2023	$535	13,586	$7,268,510.00
2024	$656	17,624	$11,561,493.00
2025*	$263	3,062	$603,935.00
Total			**$19,999,894.00**

*2025 values are inclusive of the end of PY3, March 21,2025.

DER Management Functions and Operations

Active Management Functionality and Operation

Per Implementation Plan Section G.1.11 - Operational descriptions of how active management was executed and implemented

PPL Electric has compiled a report of data captured from the ADMS/DERMS system. This report identifies the operational issues face, the active management action taken, and the expected resulting impact of the action for each instance of active management. As noted previously, within Active Management Benefits portion of this report, the data has been exported from the ADMS/DERMS event logs and presented within Appendix F. The data indicates the number and severity of voltage violations present before and after ADMS/DERMS executes the management plan. In contrast to the approach detailed previously within the Active Management Benefits, smart meter measured data is utilized but does not determine the relative role of each DER.

Prior to the execution of an active management event, ADMS/DERMS completes an iterative simulation of the impacted feeder to determine which devices will be included and their necessary power factor adjustments. The results reflect the best information available at the time the management action was taken and incorporates some voltage and load measurements received through SCADA but does not include measured smart meter voltages.

When the ADMS/DERMS is managing system voltage, it identifies voltage violations within the operational model, determines an optimal plan to mitigate voltage violations, and then calculates the hypothetical future state expected to result from that plan. The pre- and post-plan calculated values are recorded within the event log files, as well as the participating DERs and issued commands. From the pre and post event data, the estimated number of voltage violations, resolved by the ADMS/DERMS action, are calculated.

The calculated voltage violations resolved are higher than the observed voltage violations resolved, due to a variety of factors. Slight variances between the simulated and measured results are to be expected. ADMS power flow calculations incorporate real time data and utilize trend data for very near-term forecasting to project the simulated results in study area. Most observed voltage violations occur slightly outside of permissible voltage limits, as presented in Figure 8. Through the integration of the power flow solution within the active management simulations, an overestimation (and sometimes underestimation) of event responses may occur. Each power flow and optimization cycle, currently occurring approximately every 15 minutes, is largely independent from the previous cycle, potentially resulting in the same set of customer voltage violations resolutions being attributed to multiple system interventions. Additionally, the estimated voltage violation resolutions do not account for any failed communication with a participating DER Management device, resulting in a decrease in anticipated participation and subsequently realization of anticipated benefits. Finally, the power flow solution does not fully account for the actions of autonomously operating devices outside of the system's control, such as switchable capacitors and voltage regulators, which are capable of changing state or position independently of the scheduled system intervention of DER Management devices. The ability to operate independently between the pre-and post-plan results further adds to the variance between anticipated and actual voltage violation resolutions.

ADMS/DERMS also attempts to reduce the severity of voltage violations, as part of the voltage management process. While there may not yet be sufficient penetration of actively managed DERs to resolve voltage violations in all areas, ADMS/DERMS still utilizes the available resources to improve system voltage conditions. The results of these actions are also presented within Appendix F, on a per event basis.

Active Management Validation

To validate the performance of the ADMS/DERMS in addressing voltage violations, PPL Electric has compared DERMS plan logs to the observed customer voltages impacted during the 15-minute meter intervals prior to and after the execution of the planned event. The customer meter data has been sourced via the smart meter data repositories. Given the fluidity of the distribution system within each smart meter 15-minute interval, there are a multitude of contributing factors influencing distribution system, as well as customer service voltages, thereby increasing the difficulty in attributing the resolution of a voltage violation solely to DER management. It is possible, however, to assess whether the ADMS/DERMS plans generally align with and support voltage changes that are needed to improve voltage violation conditions.

Successful DER management utilizes DERs to positively impact customer and distribution system voltages during periods of high and low voltages. This has contributed to a reduction in observed customer voltage violations. PPL Electric has examined the ADMS/DERMS event logs to identify events in which a portion of participating DERs had been directed to influence the observed voltage, in the same direction so as to resist the violation. From these events, customer smart meter voltages, on the same feeder and phase as the managed DERs, are examined pre and post event to determine the influence of the subject planned event.

Due to the complexity and factors impacting the distribution system's voltage, certain events involve a mixture of DER management actions; with a portion of the DERs increasing kVAR absorption and others increasing the kVAR injection. These multi-directional events are difficult to analyze at scale and have been excluded from this analysis, to increase the clarity and understanding of DER Management action effectiveness. The results illustrated in Figure 13 below exclude said complex events.

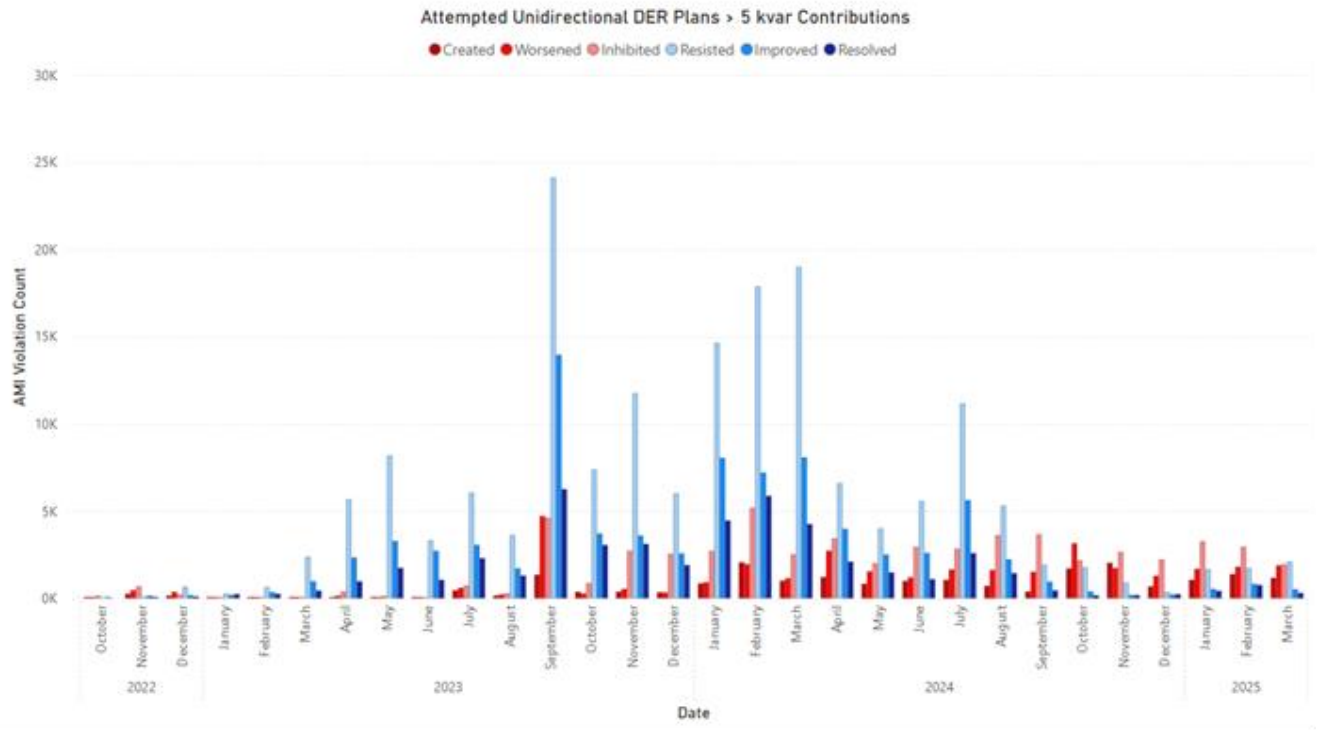

Figure 13. DER Management Plan Contribution Results

Within Figure 13, the contribution of each DER management's contribution to the change of voltage violation was categorized as follows:

- *Created*: A new voltage violation has been observed after the execution of a DER management plan, at the end of a smart meter reporting period, that did not exist prior to the management action
    - Ex: A participating DER injects kVAR which would raise system voltage, and a customer's voltage changes from 1.049 per unit to 1.051 per unit
- *Worsened*: A voltage violation was more severe in the direction of the DER management planned voltage contribution, at the end of a smart meter reporting period, than prior to the management action
    - Ex: A participating DER injects kVAR which would raise the voltage, and a customer's voltage changes from 1.051 to 1.052 per unit
- *Inhibited*: A voltage violation was less severe at the end of a smart meter reporting period, but the DER management plan's voltage contribution was in the opposite direction
    - Ex: A participating DER injects kVAR which would raise the voltage, and a customer's voltage changes from 1.052 to 1.051 per unit.
- *Resisted*: A voltage violation was more severe at the end of a smart meter reporting period, despite the DER management plan's voltage contribution in the direction opposite the violation
    - Ex: A participating DER absorbs kVAR which would lower the voltage, and a customer's voltage changes from 1.051 to 1.052 per unit.
- *Improved*: A voltage violation was less severe at the end of a smart meter reporting period in the direction of the DER management plan's voltage contribution
    - Ex: A participating DER absorbs kVAR which would lower the voltage, and a customer's voltage changes from 1.052 to 1.051 per unit.
- *Resolved*: A voltage violation existed at the start of a smart meter reporting period that did not exist at the end of the period and attributed to the DER management plan's voltage contribution
    - Ex: A participating DER absorbs kVAR which would lower the voltage, and a customer's voltage changes from 1.051 to 1.049 per unit.

Within one of the incremental software updates PPL Electric's ADMS/DERMS had received, modified the allowable minimum power factor for actively managed DERs. The ADMS/DERMS restricted impacted devices from operating outside of +/-90% power factor. Due to this process revision, the subject DERs were removed from operating autonomously, via their unique VVC, and issued power factor adjustment commands, to raise (or lower) their power factor to the +/-90% threshold, reducing available kVAR support. Previously, these DERs would have remained following their autonomous VVC settings and been permitted to contribute (or absorb) kVAR up to the programmed 44% of the kW nameplate rating, as outlined within IEEE 1547-2018. Through the issuance of these power factor adjustments, the subject DERs' contribution to local voltage violations had been reduced, resulting in the potential to contribute to an increase in the observed voltage violations, as presented within Figure 13, after September 2024. This and other potential contributing factors are currently being examined by PPL Electric, with solutions forthcoming.

Through the DER Pilot, participating DERs help support the distribution system's voltage autonomously, via unique VVCs and active management. As DER penetration continues to increase, the intertwined DER management effectiveness has become evident. Through each Pilot DER's autonomous VVC settings, DER are capable of instantaneously resisting any voltage variations outside of the individual VVC deadbands. Through this resistance to voltage changes, each DER attempts to restore the measured voltage, at the inverter, within the deadband range. During periods of excessive and/or sustained voltage outside of the DER's VVC deadband, the Company's ADMS/DERMS can intervene and establish a suitable solution and include additional actively managed DERs, if necessary. Through these solutions, commands are dispatched to DERs to improve the observed voltage and resist further voltage variances, while influencing attempts to restore the distribution system voltage within its permissible limits. Through the use of autonomous and active management techniques, PPL Electric's participating DERs have aided in the resolution of observed voltage violation conditions, improved voltage violation magnitudes (severity), and resisted other factors that contribute to the

occurrence of or increase the severity of voltage violations. While creating, worsening, or inhibiting the resolution of voltage violations are not generally desirable, nor the intention of the DER Pilot, the optimization of the distribution system is very complex and can result in trade-offs, with overall net positive results continuing to be observed. For example, creating one new voltage violation with a relatively small magnitude in order to resolve five voltage violations elsewhere on the system is a significant net positive from the system perspective.

The results of active management provided to date are a direct result of the growth in number and nameplate of actively managed DERs. As DER penetration continues to increase, the total amount of available reactive power support will continue to increase as well. While the existing DER penetration throughout PPL Electric's distribution system varies, those areas that have transitioned from low to medium, or medium to high, penetration throughout the Pilot have increased their resiliency because of the additional support provided through actively managing DERs. Active management has contributed to a decrease in instances, duration, and severity of voltage violations, as the use of fixed power factors provides a larger area of influence than available with autonomous scenarios. From Figure 14 below, most of the executed DERMS plans resulted in less than 20 kVAR, of change within the managed DER. This is attributed to the average active management DER participant's nameplate being slightly less than 16.3 kW.

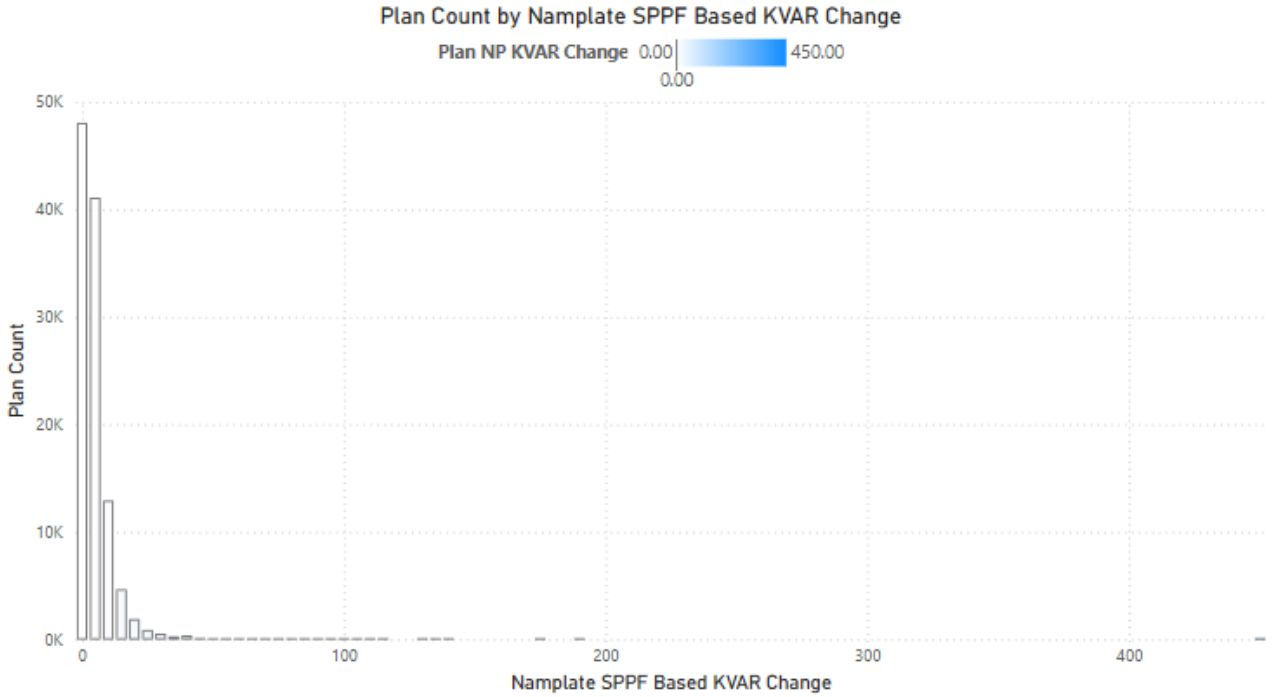

Figure 14. Relative Frequency of Total Planned kVAR Change

Active Management Communications Performance Measures

Per Implementation Plan Section G.1.12 - Performance measures related to active management

PPL Electric has developed performance tracking metrics to monitor communication reliability and overall data quality for each DER Management device installation. PPL Electric's communication systems continue to perform at a high level, even as the number of DER Management devices has increased. As noted within Table 1, the total number of device installations at the end of PY3 has reached 9,678. PPL Electric remains committed to maintaining and improving the reliability of its AMI network.

PPL Electric monitors communication between each participating customer's communication device and the AMI head-end system, ensuring overall reliability and performance of the AMI network layer. Within the AMI network, commands are transmitted via the AMI head-end system to the endpoint devices, and each endpoint device responds to the head-end system's command. One execution of this cycle is called a "round trip." The AMI layer of communications reliability and performance is measured by the percentage of successful round trips. PPL Electric strives to maintain an overall communications success rate of 95% between the AMI head-end system and DER Management devices.

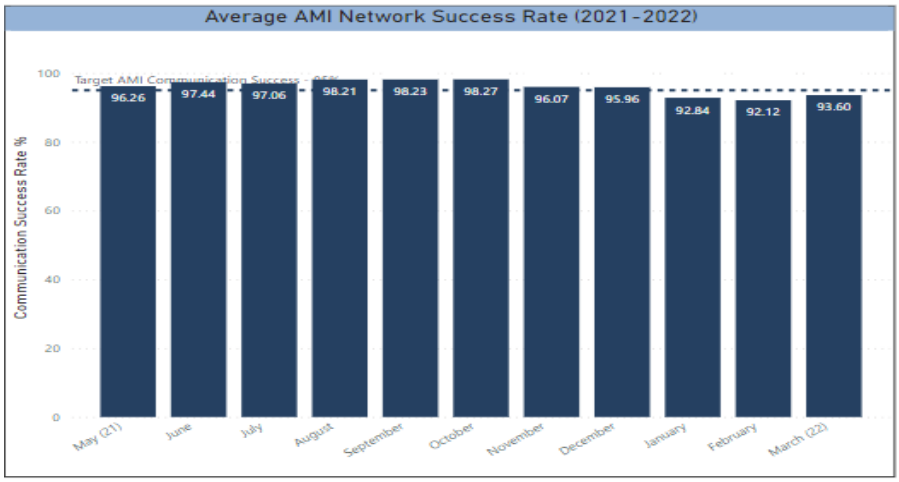

Figure 15. Average AMI Communication Success Rate by Month, 2021-2022

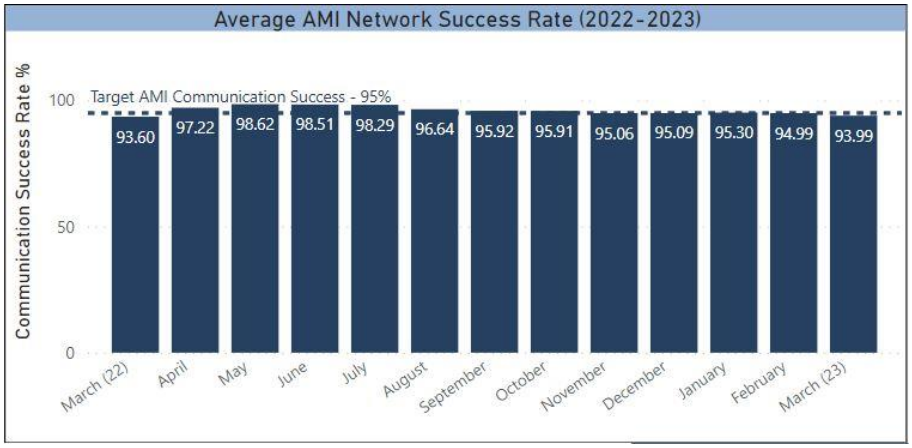

Figure 16. Average AMI Communication Success Rate by Month, 2022-2023

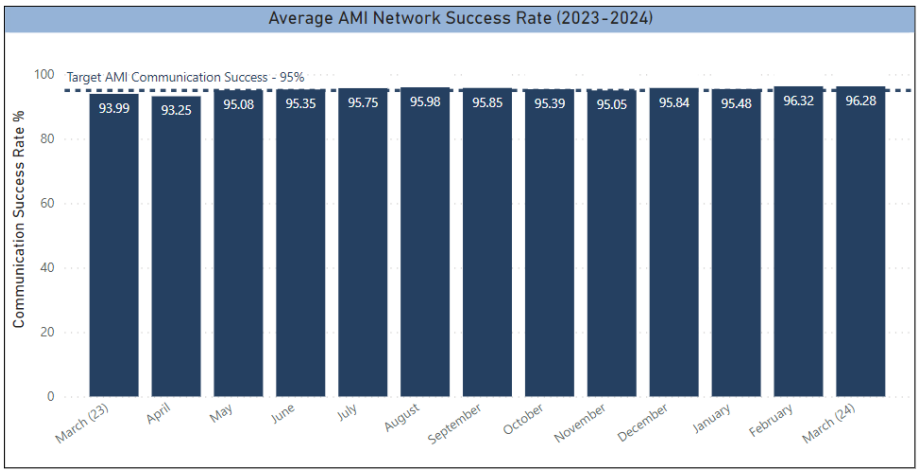

Figure 17. Average AMI Communication Success Rate by Month, 2023-2024

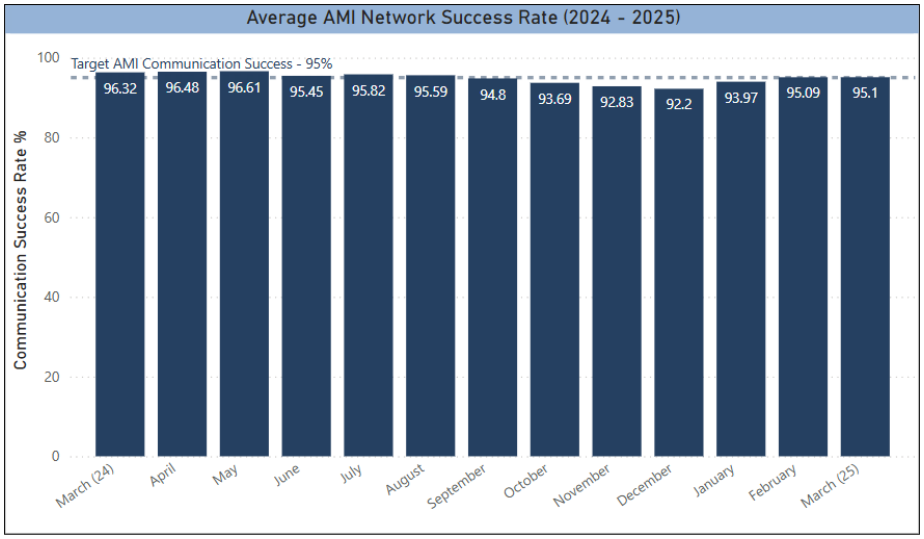

Figure 18. Average AMI Communication Success Rate by Month, 2024-2025

Within Figure 15 to Figure 18 above, the AMI communication success data excludes locations where AMI communication could not be established, as their performance is not indicative of overall network performance. As of March 2025, 587 devices have been removed from this data set. This accounts for 6.07% of DER installations enrolled in the Pilot. These locations are being investigated by PPL Electric.

Another important AMI network performance indicator is Average Round-Trip Time. This indicator measures the amount of time it takes for a command to be sent from the head-end system and the response to be returned by the radio. PPL Electric strives to maintain 60 seconds as a maximum duration of the average round trip time, to ensure reliable communications performance. Based on historical performance data, an improved target of 30 second round trip time target had been implemented for the 2023-2024 reporting timeframe and beyond. Through these decreases, round trip time monitoring continues to indicate no significant changes in network performance have occurred.

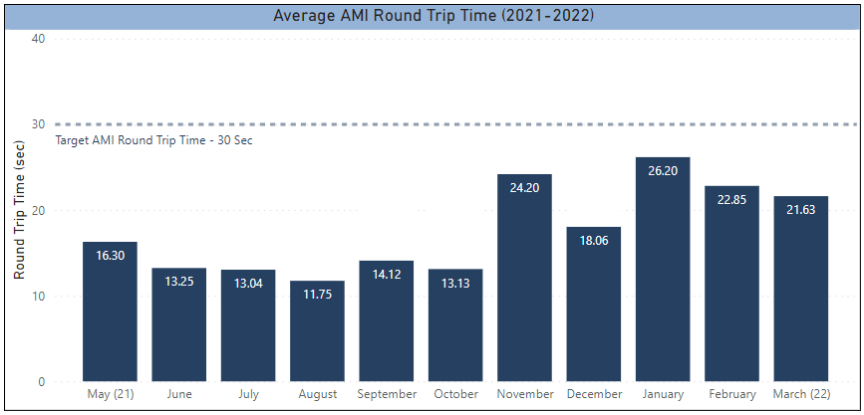

Figure 19. Average AMI Round Trip Time by Month, 2021-2022

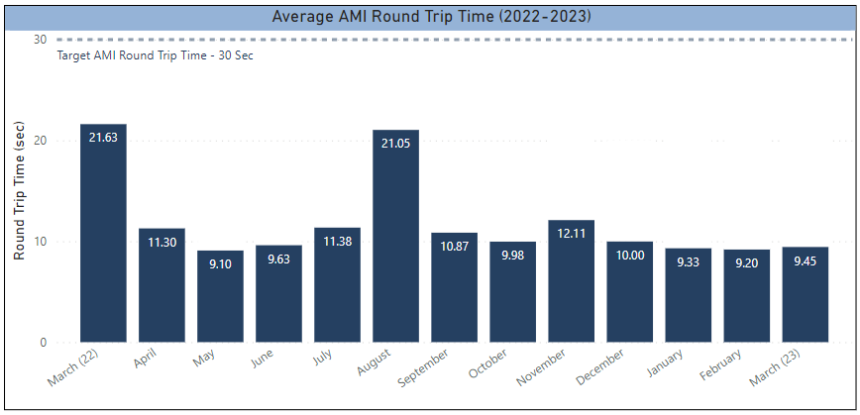

Figure 20. Average AMI Round Trip Time by Month, 2022-2023

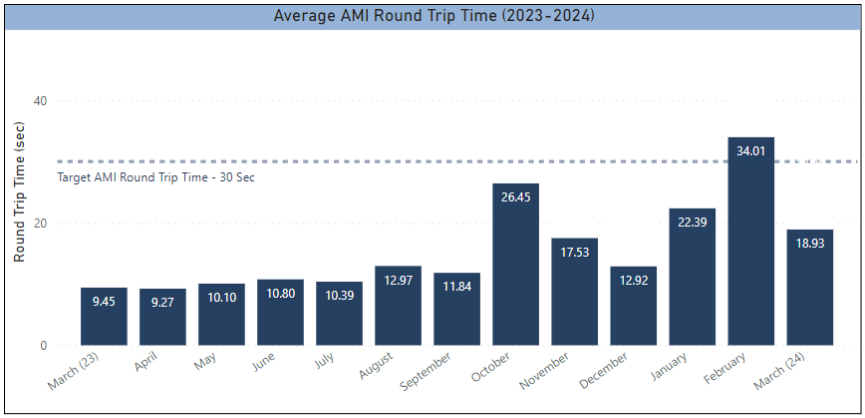

Figure 21. Average AMI Round Trip Time by Month, 2023-2024

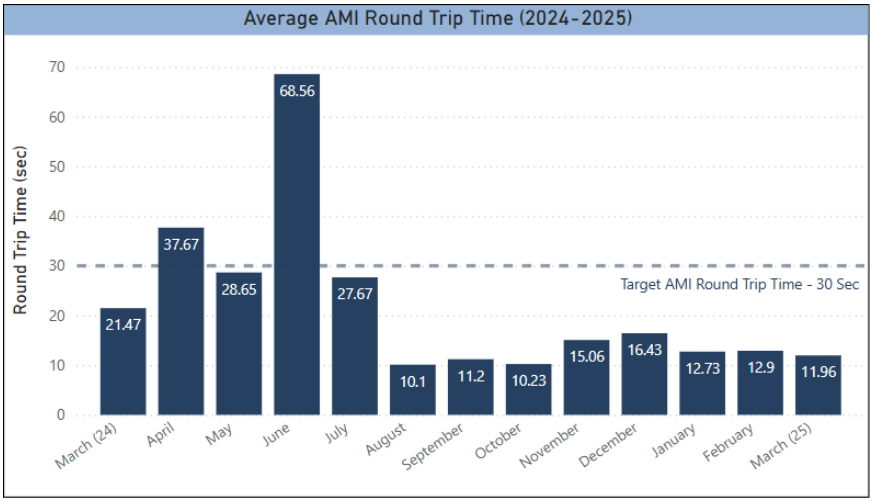

Figure 22. Average AMI Round Trip Time by Month, 2024-2025

Each DER Management device provides 5-minute interval data, increased from customer smart meters' 15-minute interval. Through this increased sampling rate, data quality is pivotal to overall communications health. With respect to active DER management, a communications interval is determined to be a "quality" interval when at least one reading within any 15-minute interval during daylight hours (5AM – 9PM) is received and the data is within reasonable limits for key parameters (i.e. voltage, kW, Volt-VAR curve points, etc.). Within the historical DER data, a new challenge had been observed: a number of inverters reported real power measurements above their rated nameplate, at times exceeding the nameplate by more than 10%. This has potential to negatively impact data quality, despite other parameters being within expected ranges.

Quality data intervals, between March 22, 2024, and March 21, 2025, decreased to 86.50% of communications intervals, from the 89.93% previously reported. PPL Electric continually monitors data quality and has identified and implemented enhancements to improve overall data quality and is committed to continuing these efforts for the foreseeable future.

Use Case Findings and Details

Per Implementation Plan Section G.1.13 - Findings and information on PPL Electric's use cases

PPL Electric has continued to compile and investigate information within each of the eight use case areas identified in the Pilot Implementation Plan. Additional investigations have also been completed, providing support for future DER Management Plan iterations. Each investigation includes a comparison of benefits between Pilot and non-Pilot participation, with related benefits detailed. Through the completion of each study, PPL Electric's knowledge base continues to expand, enhancing the Company's the benefits of active management.

The total number of uses cases, per category and reporting year, are presented in Table 16 below. As noted previously, additional detailed studies have been completed. Those studies pursued further areas of Pilot-related study but do not fall within the defined categories.

Table 16. DER Management Pilot Supporting Use Cases by Program Year

	Year 1	Year 2	Year 3
Use Case 1	0	0	
Use Case 2	6	9	10
Use Case 3	0	2	3
Use Case 4	0	1	2
Use Case 5	0	1	1
Use Case 6	4	5	3
Use Case 7	3	3	
Use Case 8	0	0	
Supplemental	0	2	3

Use Case #1 – Voltage Violation at DER Point of Interconnection (POI)

PPL Electric must maintain its distribution voltage within the parameters set forth by the Commission's regulations.[6] The threshold voltages detailed are similar to those indicated within ANSI C84.1. Maintaining the distribution system voltage within these limits is a component of ensuring safe and reliable power quality for customers. As DER penetration continues to increase, there is potential for the distribution system voltage to be negatively influenced, particularly at the POI, leading to customer voltage falling outside the allowable limits, for periods of time. The introduction of DER Management devices has increased PPL Electric's overall visibility of its distribution system. Through continuous monitoring of distribution system and customer meter voltages, PPL Electric has been able to observe and detail the benefits each Pilot group has contributed to the distribution system's voltage performance, including aiding in the mitigation of voltage violations.

For the PY3 period, 40,409 voltage violations were recorded at the meters of Pilot participants (i.e., CG1, CG2, and AM groups). As noted previously, as the number of Pilot participants increases, the number of documented POI voltage violations is anticipated to increase, based on the increasing sample sizes year over year.

Table 17. POI Voltage Violation Counts by Program Year

	Year 1	Year 2	Year 3
POI Voltage Violations	6,559	39,156	40,409

Use Case #2 – Voltage Violation Mitigated by DER on the Circuit

As noted previously, increased DER penetration can create or intensify voltage issues, particularly if no measures are in place help mitigate them. As DER penetration continues to increase, system operations and planning engineers will continue to struggle with the challenges associated with various levels of DER penetration throughout PPL Electric's distribution system. Through DER Pilot, the Company has increased visibility and management capabilities throughout its distribution system.

The Company has conducted detailed reviews of past voltage events to determine the measurable impact of active DER management. Most of these examinations have considered the integration and impact of all existing DERs. Additionally, detailed examinations of DERMS operations have detailed the influence of specific DERMS actions on the observed voltage violations.

[6] *See* 52 Pa. Code § 57.14.

As of March 21, 2025, 10 whitepapers focusing on this use case have been completed. From Table 18, 8 of these studies show a total of 887 potential voltage violations being mitigated through the application of autonomous VVCs and an additional 878 voltage violations being mitigated via active management. Additionally, PPL Electric has conducted a detailed examination of one DER management event by comparing the DERMS-calculated voltage violation mitigation estimates against the actual smart meter data readings over the same intervals. This examination indicated 3 voltage violations were mitigated via active management intervention, during the intervals identified within the DERMS calculation.

Table 18. Use Case 2 - Voltage Violation Studies, Program Year 3

	Trigger	Customers Violations	Violations Resolved - Autonomous	Additional Resolved – Active Management
WP-0050	Switching	136	90	46
WP-0053	High Voltage	436	78	289
WP-0055	High Bus Voltage	743	439	113
WP-0060	Switching	151	34	117
WP-0061	Ride Through Settings	n/a	n/a	n/a
WP-0063	High Bus Voltage	152	49	103
WP-0064	Low Voltage	202	194	8
WP-0065	High Voltage	223	3	199
WP-0066	LVM Review	49		3
WP-0072	Customer Reporting	n/a	n/a	n/a

Use Case #3 – Voltage Violation During Planned Switching

Portions of the distribution system must be reconfigured routinely under planned switching events. Through these events, all or a portion of a feeder may be transferred from its normally assigned source to an alternate, placing the impacted areas in an abnormal state. These events enable planned maintenance and upgrade activities to be completed and can allow for portions of the distribution system to be de-energized.

Through each planned switching event, all interconnected DERs within the transferred area are transferred to the new source. These transfers may increase the potential for an increase in observed voltage violations. Before these events are executed, PPL Electric completes proactive switching reviews to identify any loading and voltage issues that may be anticipated and determines the paths to mitigate these issues. Attempts to mitigate these are assessed based on the complexity of implementation (i.e., adjustments to voltage and power factor correcting device settings, phase balancing, additional load transfers, etc.).

The DER Management team may further examine these studies in detail to assess the potential impact DER Pilot participants may have in providing an alternate or supportive function in resolving the anticipated voltage issues. Through these examinations, both autonomous and active management functions are assessed to determine their potential impact throughout the abnormal configuration period.

As of March 21, 2025, 3 studies have been completed that have identified the ability to utilize DER Management participants to reduce anticipated voltage violations and aid in the reduction of additional reconfigurations or installation of temporary voltage and power factor correcting devices. Through these examinations, a potential reduction of $499,000 in planned switching costs has been determined, as illustrated in Table 19.

Table 19. Potential Cost Savings Attributed to Use Case 3 – Voltage Violations During Planned Switching Studies, Program Year 3

	Trigger	Potential Cost Savings
WP-0049	Substation Maintenance	$154,000
WP-0051	Substation Maintenance	$ n/a
WP-0052	Substation Maintenance	$345,000

Use Case #4 – System Restoration

If an outage occurs for a period longer than the programmed ride-through settings (as detailed within Ride-Through Curve Parameters, above), all IEEE 1547-2018 compliant devices are programmed to disconnect from the distribution system in order to avoid potential unintentional islanding. Currently, all Pilot participating DERs are programmed with a 5-minute delay, upon restoration occurring, while non-Pilot participants do not have this delay programmed. During this restoration window, the feeder/substation is required to supply all customer load, via the supplying transmission system, without any support from the aforementioned DERs. Therefore, the observed cold load pick-up at the point of restoration is dependent on the outage duration and includes the native load, without DER masking, and a reduction in load diversity.

Throughout PY3, PPL Electric has not identified any system restoration events that have resulted in overloaded equipment attributed to the inclusion of masked load (load masked by DERs) during cold load pick-up periods. Analysis has been completed on several feeders, with an emphasis on assessing potential risks in the future due to these conditions. A further examination considering the impact of residential EV charging during system restoration, has also been examined, as highlighted within Table 20 below.

Table 20. Use Case 4 – System Restoration Switching Studies, Program Year 3

	Driver
WP-0067	Evaluation of masked loading towards ability to defer capital investments
WP-0071	System Restoration with consideration of residential EV charging

Use Case #5 – Masked Load Impact on Load Forecasting

PPL Electric reviews each feeder's summer and winter peak loading to assess potential device overloading risks. In addition to these semi-annual assessments, a review of the current load masked by DERs, throughout the distribution system, is conducted. The assessment of masked load is required within native load calculations and determines non-telemetered DERs' contributions to the distribution system. The calculated masked load, along with the telemetered DERs and measured load, comprise the native load. The completion of native load calculations within load forecasting helps ensure that capital investments are appropriately timed, particularly for periods when DERs may not be available.

As of the end of PY3, PPL Electric has calculated 38.8 MW of masked load, during system peak loading period, July 2024. This value was calculated by monitoring the output data from 64.08 MW of DER nameplate capacity at the system peak. Detection of the masked load has resulted in 25.28 MW of additional system capacity during these peak loading periods. PPL Electric has also performed analysis on several feeders to evaluate the potential impact of masked load on future load forecasting, with these results detailed within the associated studies referenced within Table 21.

Table 21. Use Case 5 - Masked Load Impact on Load Forecasting White Paper Results, Year 3

	Driver
WP-0067	Evaluation of masked loading towards ability to defer capital investments
WP-0069	Evaluation of masked loading towards ability to defer capital investments

Use Case #6 – DER Management Impact on Voltage Management

PPL Electric's DER Pilot has increased the overall number of telemetered devices deployed throughout the distribution system. With the addition of these new telemetered devices and the previous deployment of smart meters, PPL Electric can better study and monitor its distribution system's operation. In particular, the addition of these devices has increased the resolution within reliability focused investigations and has enabled a greater overall understanding of each feeder's profile.

PPL Electric's DER Pilot also enables the Company to assess participating DERs' impact on feeder and substation voltage. Based on this analysis, participating DERs have reduced the overall number, duration, and severity of voltage violations. As DER penetration continues to increase, the ability for participating DER to positively impact the distribution system voltage will continue.

As part of each interconnection and DER management study, PPL Electric investigates DERs' impacts on distribution system voltage. Modeling accuracy has continued to increase by integrating DER Pilot telemetered data as well as smart meter data for each participating DER customer location. This has enabled a greater number of scenarios to be examined, reducing the deviation between simulated/anticipated results and observed results. Within these studies, the assignment of existing and new DERs into the appropriate group enables further assessment of anticipated impacts throughout a variety of situations.

At the conclusion of DER Pilot's PY3, 3 studies have been completed, assessing potential interconnection capital investment reductions, attributed to DERs becoming Pilot participants. An overview of each of these studies, and corresponding potential capital avoidance, can be found in Table 22 below.

Table 22. Use Case 6 - DER Management Impact on Voltage Management White Paper Results, Program Year 3

	Trigger	Avoided Capital	Violation Reduction
WP-0048	3MW DER Addition	$105,000	34
WP-0057	3MW DER Addition	$900,000	n/a
WP-0059	21MW DER Addition	$560,440	153

Use Case #7 – DER Active Management Impact on Hosting Capacity Increase and Deferral of Capital Upgrade

Hosting capacity is the amount of DERs that can be added to a portion of the distribution system before system reinforcements are needed to prevent a load or voltage violation. The cumulative value for each feeder and/or substation bus represents the total DER hosting capacity available, based on the dates and times selected for the completed analysis. Currently, DER hosting capacity is calculated annually, in support of preparing this report. Through the DER Pilot, PPL Electric has increased the total number of DER telemetry points available and has improved each successive iteration of the DER hosting capacity calculations as well as DER system impact examinations.

The DER hosting capacity compares four iterations of DER output and management to assess variances: DER nameplate capacities, monitored output, autonomous functions and active management. While the first iterations of the

comparison utilize all PV DER within the calculations, the latter two iterations are dependent on the DER Pilot group assignments, as not all DERs are Pilot participants.

Based on customer DER interconnection applications, the scenarios detailed above are utilized to determine whether participating DERs can alleviate interconnection restrictions or reduce potential customer funded capital investment requirements. At the conclusion of PY3, only one study has been completed, within this use case category.

Table 23. Use Case 7 - DER Active Management Impact Study Results, Year 3

	Trigger	DER Hosting Capacity Increase – Autonomous	DER Hosting Capacity Increase – Active Management
WP-0072	Year 3 DER Hosting Capacity	18 MW	35 MW

Use Case #8 – DER Operations in Emergency Conditions and in Active Work Zones

Every utility needs to be prepared to respond to emergency situations, as they arise. Through PPL Electric's preparedness, field personnel are dispatched to investigate and support the resolution of reported fires, gas leaks, downed conductor, etc. Through these responses, portions of the distribution system may need to be de-energized, to ensure public and equipment safety, during this time. With the DER Pilot, PPL Electric system operators can remotely disconnect Pilot participants, within these work areas, reducing the potential for areas to be accidentally re-energized. While reductions in potential safety hazards may be possible within work areas, continued vigilance and safety measures are still necessary.

There were 1,723 outage events during PY3, where DER Pilot participants were present and potentially presented a risk of unintentional islanding, though continued operation. Because of Pilot participation, the status of the impacted DERs was able to be verified, and no instances of unintentional islanding were detected. Also, in PY3, there were no instances where a participating DER was intentionally disconnected through communications with the inverter.

Additional Study: Flexible Interconnection

In addition to the studies detailed within the Pilot Implementation Plan, 3 flexible interconnection investigations were completed. Each of these studies examined the integration of DERs with additional parameters beyond those currently available under the DER Pilot. The future integration of flexible interconnection will enable an increase in local DER penetration, while avoiding costly capital investments, by reducing participating DERs' output during peak distribution congestion periods. An overview of the results of these studies can be found in Table 24 below.

Table 24. Additional Areas of Study - Flexible Interconnection Study Results

	Driver	Avoided Capital Investment
WP-0058	10 MW DER Addition	$1,480,000
WP-0062	2.5 MW DER Addition	$365,000
WP-0068	21 MW DER Addition	$560,440

Appendix A: Volt-VAR Curve Programming

Appendix B: Aggregate Active Management Event Count

Appendix C: Grid Benefits Achieved in Each Instance of Active Management

Appendix D: Generation Loss or Gain Event Table

Appendix E: DER Hosting Capacity

Appendix F: Active Management Operational Implementation Event Logs

Citizens' Statement No. 5

BEFORE

THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	**:**	
	:	
v.	**:**	**Docket No. R-2025-_____**
	:	
Citizens' Electric Company of Lewisburg, PA	**:**	

DIRECT TESTIMONY

AND EXHIBITS

OF

KATHY STAUDER

ON BEHALF OF

CITIZENS' ELECTRIC COMPANY OF LEWISBURG, PA

APRIL 30, 2025

BEFORE

THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	**:**	
	:	
v.	**:**	**Docket No. R-2025-_____**
	:	
Citizens' Electric Company of Lewisburg, PA	**:**	

DIRECT TESTIMONY OF KATHY STAUDER
ON BEHALF OF CITIZENS' ELECTRIC COMPANY OF LEWISBURG, PA

Q. Please state your name and business address.

A. My name is Kathy Stauder, and my business address is 1775 Industrial Blvd., Lewisburg, Pennsylvania.

Q. By whom are you employed and in what capacity do you serve at Citizens' Electric Company of Lewisburg, PA?

A. I am employed by C&T Enterprises, Inc. ("C&T"), and assigned to Citizens' Electric Company of Lewisburg, PA ("Citizens'" or "Company") as Treasurer.

Q. Please describe your duties in this capacity.

A. My duties are to organize, direct, and coordinate the financial department. I provide administrative direction and oversight for billing for electric service to consumers. I also advise the President & CEO of the financial aspects of the company, manage the financial record keeping, coordinate the budget, coordinate with computer services, and coordinate with consumer services.

Q. Please describe your employment and educational background.

A. I have an Accounting and MBA degrees from Bloomsburg University. Before joining C&T, I was Vice-President of Finance at Remmey Pallet Company and Director of Finance at Playworld Systems.

Q. What are your responsibilities with respect to this filing?

A. As Treasurer, I am responsible for coordinating with our auditors and representatives of Company witness Mr. Gorman to ensure that historic and test year expenses, taxes, revenues, and rate base are appropriately reflected.

Q. Are Citizens' records regularly audited by a licensed accounting firm?

A. Yes. The accounting firm of FORVIS MAZARS, LLP ("FORVIS") audits the Company's financial records. They prepare an annual report of the Company operations and assist Company personnel with specific PUC filings, such as our State Tax Adjustment Surcharge ("STAS") filings. They also prepare our tax returns. A copy of our Annual Report for the year ended December 31, 2024, is attached as Exhibit__(KS-1). Our most recent Federal and State tax returns are included in Volume III of the filing as Joint Confidential Exhibit 4 and Citizens' Confidential Exhibit 3.

Q. Is Citizens' proposing to roll-in its STAS?

A. Yes. Mr. Gorman has reflected the current levels of state taxes in his analysis. As a result, the current STAS is being rolled-into base rates. When the new rates take effect, we will adjust the then-applicable STAS rate to reflect any difference between the then-applicable tax levels and the ones that were rolled-into base rates. Our most recent STAS filing is included as Exhibit__(KS-2).

Q. Do you have any comments regarding the future test year expenses?

A. Yes. Attached as Exhibit__(KS-3) is a table showing the operating expenses for the Historic Test Year ("HTY"), Future Test Year ("FTY") and Fully-Projected Future Test Year ("FPFTY"). The table includes our actual FTY expenses through March 31, 2025. Our expenses are tracking as we would expect through March 31, 2025. We will continue to update this information on a quarterly basis during the proceeding.

Q. Did you compile a similar comparison of future test year plant?

A. Yes. Attached as Exhibit__(KS-4) is a table showing the utility plant for the HTY, FTY and FPFTY, as well as actual plant as of March 31, 2025.

Q. What depreciation changes is the Company proposing for this filing?

A. We are proposing to reduce the useful life of our computer equipment and software from 5 years to 3 years. This is consistent with the replacement cycle for IT equipment that we follow, and is also consistent with the warranty period on new equipment. If this change is accepted by the Commission, we will make it going forward in 2026.

Q. Is it unusual for Citizens' expenses and plant by Account to vary from quarter to quarter during the year?

A. No. For many of our Accounts, our actual expenses vary quarter-to-quarter based on the activities that our workers and contractors are doing. Over the entire year, there can be some overall variation if more of our work is done on projects that are expensed rather than projects that are capitalized. Mr. Johnson will explain how the types of projects and focus of our workers may vary during the various quarters of the year. The expenses can also vary due to unexpected weather or other circumstances.

Q. How did the Company develop the financial data provided to HSG Group?

A. The HTY data is based on actual experiences during the historic test year ending December 31, 2024. The FTY data is based largely on our operating budget for the year ending December 31, 2025, with updates for any known and measurable changes that we have identified between the date that budget was approved by our Board of Directors and April 2025 when we are submitting this filing. The FPFTY data is based on our projections for the year ending December 31, 2026.

Q. Please discuss the major expense categories for Citizens'.

Citizens' expenses are budgeted and tracked in the following categories: (1) Labor & Overheads, including C&T Shared Services; (2) Transportation; (3) Materials & Supplies (4) Administrative & General; (5) Outside Services; (6) Uncollectibles; (7) Depreciation & Amortization; (8) Regulatory Fees; and (9) Taxes. Citizen's also reports by account, corresponding to the FERC chart of accounts. Each Operating and Maintenance includes (as appropriate) costs for Labor, Overhead, Material and Transportation. The information provided to Mr. Gorman is by FERC account, with subaccounts for Labor, Overhead, Material and Transportation.

Q. What is the largest expense category?

A. Labor & Overheads constitute the largest expense item. This category includes our employees and the various benefits that we provide (health, dental, vision, retirement, etc.). To develop the projected 2025 costs for Labor & Overheads, we examined the wages and benefits for our employees. This included the impacts of the Wage & Salary Study discussed by Mr. Johnson and the annual compensation adjustment discussed by Ms. Sullivan. In doing so, we made several adjustments to the prior year to reflect positions

that were open and also to reflect new positions that we will be adding during 2025. Ms. Sullivan's testimony discusses the C&T Shared Services and insurance benefits.

Q. Have you prepared an exhibit showing the impact of the salary changes and the position changes for the FTY and FPFTY?

A. Yes. Attached as Exhibit__(KS-5) is an analysis that supports that impact. The impact of these changes are distributed among the various FERC accounts that Mr. Gorman reflects in his analysis according to where the employee's time is booked (based on activities performed).

Ms. Sullivan's testimony discusses the 2025 and projected 2026 C&T base compensation adjustments. Ms. Sullivan also discusses the C&T Shared Services that are included in our Labor & Overheads for 2024, 2025 and 2026.

Q. Please discuss the Transportation projections.

A. This item reflects the costs of our vehicles and other equipment, including fuel and maintenance expenses. For 2025 and 2026, we are projecting vehicle and equipment purchases, including a $425,000 bucket truck in 2025.

Q. Is Citizens' projecting increased Materials and Supplies costs?

A. Yes. The various materials and supplies for our business have increased consistent with general inflation of many items. We included a 3% increase for office supplies. Mr. Johnson will address the increases in our materials.

Q. Please discuss the costs incurred by Citizens' for Administrative and General.

A. The items in this category include the general costs to heat, furnish and maintain our office space and warehouses.

Q. What costs are included in Outside Services?

A. Outside Services includes the charges by various vendors for their service. This includes attorneys, accountants, auditors, consultants, cleaning vendors and contractors that we hire for capital projects. Most of the construction contractor expense would be capitalized rather than expensed.

Q. Could costs in the other categories that you addressed above be capitalized rather than being expensed?

A. Yes. As part of this filing, we have made assumptions regarding the portion of Labor & Overheads, Transportation, Materials & Supplies and Administrative & General that will be capitalized rather than expensed. We have done this based on both historic experience and projected 2025 and 2026 capital projects.

Q. How did Citizens' develop the Uncollectible expenses?

A. Uncollectible expense is based on historical experience.

Q. Please discuss the Depreciation and Amortization expense reflected in the filing.

A. Depreciation expense is developed by Mr. Gorman, Exhibit__(HSG-1), Schedule C3 and explained in his testimony.

Q. Finally, what Regulatory Fees and Taxes are reflected in the filing?

A. These are developed by Mr. Gorman, Exhibit__(HSG-1), Schedule C1-3, and explained in his testimony.

CITIZENS' FINANCING ACTIVITIES

Q. Please explain the Company's financing arrangements.

A. Citizens' primary source of financing is its parent company, C&T Enterprises, Inc., which obtains long-term loans, lines of credit and letters of credit on Citizens' behalf through the National Cooperative Servicing Corporation ("NCSC"). Each long-term loan is

supported by a Securities Certificate approved by the Commission. Ms. Sullivan provides an exhibit with details of each loan. We also have access to a short-term line of credit through C&T, as described by Ms. Sullivan.

Finally, we maintain a local banking relationship with Mifflinburg Bank & Trust Company.

AFFILIATE CHARGES

Q. Does Citizens' have any affiliate charges in the HTY, FTY or FPFTY in addition to the ones with C&T that are discussed by Ms. Sullivan?

A. No.

Q. Does this conclude your testimony at this time?

A. Yes.

Citizens' Statement No. 5

BEFORE

THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	**:**	
	:	
v.	**:**	**Docket No. R-2025-_____**
	:	
Citizens' Electric Company of Lewisburg, PA	**:**	

EXHIBITS

OF

KATHY STAUDER

ON BEHALF OF

CITIZENS' ELECTRIC COMPANY OF LEWISBURG, PA

APRIL 30, 2025

Citizens' Electric Company of Lewisburg, Pa.

Independent Auditor's Report, Financial Statements and Supplementary Information

December 31, 2024 and 2023

Citizens' Electric Company of Lewisburg, Pa.
Contents
December 31, 2024 and 2023

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Forvis Mazars, LLP
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St. Louis, MO 63102
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Independent Auditor's Report

Board of Directors
Citizens' Electric Company of Lewisburg, Pa.
Lewisburg, Pennsylvania

Opinion

We have audited the financial statements of Citizens' Electric Company of Lewisburg, Pa. (Company), which comprise the balance sheets as of December 31, 2024 and 2023, and the related statements of income, stockholder's equity, and cash flows for the years then ended, and the related notes to the financial statements.

In our opinion, the accompanying financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2024 and 2023, and the results of its operations and its cash flows for the years then ended in accordance with accounting principles generally accepted in the United States of America.

Basis for Opinion

We conducted our audits in accordance with auditing standards generally accepted in the United States of America (GAAS). Our responsibilities under those standards are further described in the "Auditor's Responsibilities for the Audit of the Financial Statements" section of our report. We are required to be independent of the Company and to meet our other ethical responsibilities, in accordance with the relevant ethical requirements relating to our audits. We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Responsibilities of Management for the Financial Statements

Management is responsible for the preparation and fair presentation of the financial statements in accordance with accounting principles generally accepted in the United States of America, and for the design, implementation, and maintenance of internal control relevant to the preparation and fair presentation of financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the financial statements, management is required to evaluate whether there are conditions or events, considered in the aggregate, that raise substantial doubt about Company's ability to continue as a going concern within one year after the date that these financial statements are available to be issued.

Auditor's Responsibilities for the Audit of the Financial Statements

Our objectives are to obtain reasonable assurance about whether the financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditor's report that includes our opinion. Reasonable assurance is a high level of assurance but is not absolute assurance and therefore is not a guarantee that an audit conducted in accordance with GAAS will always detect a material misstatement when it exists. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control. Misstatements are considered material if there is a substantial likelihood that, individually or in the aggregate, they would influence the judgment made by a reasonable user based on the financial statements.

In performing an audit in accordance with GAAS, we:

- Exercise professional judgment and maintain professional skepticism throughout the audit.

- Identify and assess the risks of material misstatement of the financial statements, whether due to fraud or error, and design and perform audit procedures responsive to those risks. Such procedures include examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements.

- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of Company's internal control. Accordingly, no such opinion is expressed.

- Evaluate the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluate the overall presentation of the financial statements.

- Conclude whether, in our judgment, there are conditions or events, considered in the aggregate, that raise substantial doubt about Company's ability to continue as a going concern for a reasonable period of time.

We are required to communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit, significant audit findings, and certain internal control-related matters that we identified during the audit.

Supplementary Information

Our audits were conducted for the purpose of forming an opinion on the financial statements that collectively comprise the Company's basic financial statements. The supplementary information listed in the table of contents is presented for purposes of additional analysis and is not a required part of the basic financial statements. Such information is the responsibility of management and was derived from and relates directly to the underlying accounting and other records used to prepare the basic financial statements.

The information has been subjected to the auditing procedures applied in the audit of the basic financial statements and certain additional procedures, including comparing and reconciling such information directly to the underlying accounting and other records used to prepare the basic financial statements or to the basic financial statements themselves, and other additional procedures in accordance with auditing standards generally accepted in the United States of America. In our opinion, the information is fairly stated in all material respects in relation to the basic financial statements as a whole.

The basic financial statements of Citizens' Electric Company of Lewisburg, Pa. for the years ended December 31, 2022, 2021, and 2020, (none of which is presented herein) were audited by us in accordance with auditing standards generally accepted in the United States of America, and we expressed an unmodified opinion on those basic financial statements. In our opinion, the information for 2022, 2021, and 2020, presented on page 19 is fairly stated, in all material respects, in relation to the basic financial statements as a whole.

Forvis Mazars, LLP

St. Louis, Missouri
March 12, 2025

Citizens' Electric Company of Lewisburg, Pa.
Balance Sheets
December 31, 2024 and 2023

	2024	2023
ASSETS		
Utility Plant, at Cost		
Electric plant in service	$ 30,802,761	$ 29,509,881
Accumulated depreciation	(15,229,615)	(14,740,113)
	15,573,146	14,769,768
Construction work in progress	119,314	175,214
Net utility plant	15,692,460	14,944,982
Other Assets and Nonutility Property		
Nonutility property	21,704	21,704
Goodwill, net	3,978,203	3,978,203
Regulatory assets	112,581	172,817
Cash surrender value of life insurance	175,925	160,044
Other	70,346	67,040
Total Other Assets and Nonutility Property	4,358,759	4,399,808
Current Assets		
Cash and cash equivalents	553,348	551,746
Accounts receivable		
Customers, net of allowance 2024 and 2023 - $35,000	1,173,451	1,456,491
Unbilled revenues	1,100,909	1,020,029
Other	101,732	81,514
Advances, affiliates	90,700	90,700
Inventories	303,686	295,406
Prepaid expenses and other	31,769	38,219
Under collected power costs	263,044	138,131
Total Current Assets	3,618,639	3,672,236
Total Assets	$ 23,669,858	$ 23,017,026

See Notes to Financial Statements

	2024	2023
LIABILITIES AND STOCKHOLDER'S EQUITY		
Stockholder's Equity		
Common stock, par value $10 per share; authorized 200,000 shares; issued 139,472 shares; outstanding 134,702 shares	$ 1,394,720	$ 1,394,720
Paid-in capital	1,236,168	1,236,168
Retained earnings	11,728,535	11,443,312
	14,359,423	14,074,200
Treasury stock, at cost; 4,770 shares	(376,830)	(376,830)
Total Stockholder's Equity	13,982,593	13,697,370
Long-Term Debt	1,540,746	1,649,104
Finance Lease Liabilities	432,598	255,939
Current Liabilities		
Current maturities of long-term debt	108,359	145,289
Current maturities of finance lease liabilities	90,626	57,584
Line of credit	3,300,000	2,600,000
Accounts payable		
Trade	136,305	155,972
Related party	229,797	218,124
Due for purchased electricity	839,832	883,855
Accrued expenses	291,139	286,863
Customer deposits	299,385	257,839
Accrued taxes, net	38,360	307,082
Total Current Liabilities	5,333,803	4,912,608
Deferred Charges and Other Liabilities		
Deferred income taxes	1,645,300	1,698,300
Accrued postretirement cost	555,864	613,934
Regulatory liability	176,954	187,771
Deferred benefits	2,000	2,000
Total Deferred Charges and Other Liabilities	2,380,118	2,502,005
Total Liabilities and Stockholder's Equity	$ 23,669,858	$ 23,017,026

Citizens' Electric Company of Lewisburg, Pa.
Statements of Income
Years Ended December 31, 2024 and 2023

	2024	2023
Operating Revenues	$ 16,378,412	$ 20,412,472
Operating Expenses		
Power	9,682,484	13,730,344
Distribution expenses		
Operation	981,866	978,730
Maintenance	644,907	691,018
Customer accounts	536,671	531,968
General and administrative	1,198,237	1,167,441
Depreciation	1,126,433	1,066,173
Taxes, other than income	978,426	1,285,061
	15,149,024	19,450,735
Operating Income Before Interest and Other Expenses	1,229,388	961,737
Other Income (Expenses)		
Interest expense	(307,972)	(268,687)
Acquisition debt expense	(556,189)	(556,189)
Other income	54,873	87,604
Other expense	(23,767)	(24,587)
	(833,055)	(761,859)
Income Before Income Taxes	396,333	199,878
Provision (Credit) for Income Taxes	68,810	(76,523)
Net Income	$ 327,523	$ 276,401

Citizens' Electric Company of Lewisburg, Pa.
Statements of Stockholder's Equity
Years Ended December 31, 2024 and 2023

	Common Stock	Paid-in Capital	Retained Earnings	Treasury Stock	Total
Balance, January 1, 2023	$ 1,394,720	$ 1,236,168	$ 11,207,311	$ (376,830)	$ 13,461,369
Net income	-	-	276,401	-	276,401
Dividends	-	-	(40,400)	-	(40,400)
Balance, December 31, 2023	1,394,720	1,236,168	11,443,312	(376,830)	13,697,370
Net income	-	-	327,523	-	327,523
Dividends	-	-	(42,300)	-	(42,300)
Balance, December 31, 2024	$ 1,394,720	$ 1,236,168	$ 11,728,535	$ (376,830)	$ 13,982,593

See Notes to Financial Statements

Citizens' Electric Company of Lewisburg, Pa.
Statements of Cash Flows
Years Ended December 31, 2024 and 2023

	2024	2023
Operating Activities		
Net income	$ 327,523	$ 276,401
Items not requiring (providing) cash		
Depreciation and amortization	1,212,725	1,188,013
Deferred income taxes	(53,000)	(166,500)
Increase in cash surrender value of life insurance	(15,881)	(18,321)
Changes in		
Accounts receivable	181,942	353,560
Inventories	(8,280)	(74,693)
Regulatory assets and liabilities	(36,873)	(36,120)
Prepaid expenses and other assets	3,144	4,966
Accounts payable and accrued expenses	(3,776)	(40,686)
Due for purchased electricity	(44,023)	(651,150)
Customer deposits	41,546	33,865
Accrued postretirement costs	(58,012)	(38,431)
Accrued taxes, net	(268,722)	159,776
Over collected power costs	(124,913)	29,866
Net Cash Provided by Operating Activities	1,153,400	1,020,546
Investing Activity		
Additions to utility plant, net	(1,599,214)	(1,673,153)
Net Cash Used in Investing Activity	(1,599,214)	(1,673,153)
Financing Activities		
Borrowings under line of credit agreement	1,800,000	3,000,000
Repayments under line of credit agreement	(1,100,000)	(1,900,000)
Principal payments on finance lease liabilities	(64,996)	(110,652)
Principal payments on long-term debt	(145,288)	(140,866)
Dividends paid	(42,300)	(40,400)
Net Cash Provided by Financing Activities	447,416	808,082
Increase in Cash and Cash Equivalents	1,602	155,475
Cash and Cash Equivalents, Beginning of Year	551,746	396,271
Cash and Cash Equivalents, End of Year	$ 553,348	$ 551,746
Supplemental Cash Flows Information		
Interest paid	$ 307,972	$ 268,687
Income taxes paid	$ 113,000	$ 113,000
Right-of-use asset obtained in exchange for new finance lease liability	$ 274,697	$ -

Citizens' Electric Company of Lewisburg, Pa.
Notes to Financial Statements
December 31, 2024 and 2023

Note 1. Nature of Operations and Summary of Significant Accounting Policies

Nature of Operations

Citizens' Electric Company of Lewisburg, Pa. ("Company"), a wholly-owned subsidiary of C&T Enterprises, Inc. ("C&T"), is a regulated public utility distributing electric service to customers in parts of Union and Northumberland Counties, Pennsylvania. The Company's operations are regulated by the Pennsylvania Public Utility Commission ("PUC"). The Company extends unsecured credit to its customers.

Basis of Accounting

The Company maintains its accounting records in accordance with the Federal Energy Regulatory Commission's ("FERC") uniform system of accounts for public utilities as modified and adopted by the PUC. The accompanying financial statements and the related notes have been prepared on the basis of U.S. generally accepted accounting principles ("GAAP").

In accordance with FERC guidelines, the Company also maintains its accounts in accordance with Codification Topic 980, *Regulated Operations*. On a regular basis, the Company reevaluates its application of accounting for regulated operations. The Company has determined that regulatory assets and liabilities should continue to be accounted for under provisions of Codification Topic 980 because it is reasonable to assume that the Company will continue to be able to charge and collect its cost of service-based rates.

Purchased Power

The Company purchases power under a default service plan that utilizes a third party generator to fulfill its requirements under the current plan. The plan, which was approved by the PUC, allows for full recovery of the cost of energy supply and all related costs, including legal and consulting fees and allows adjustments to rates to reflect current market conditions. Power costs can be different than what is recovered in base charges, resulting in over or under collected power costs.

Use of Estimates

The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates. Significant estimates include unbilled revenues, depreciation, goodwill and postretirement benefits.

Cash and Cash Equivalents

The Company considers all liquid investments with original maturities of three months or less to be cash equivalents. At December 31, 2024 and 2023, cash equivalents consisted primarily of a daily investment fund account.

At December 31, 2024, the Company's cash accounts did not exceed federally insured limits.

Accounts Receivable

Accounts receivable include billed and unbilled amounts for services provided to customers for which the Company has an unconditional right to payment. The Company provides an allowance for credit losses, which is based upon a review of outstanding receivables, historical collection information and existing economic conditions adjusted for current conditions and reasonable and supportable factors.

Accounts receivable are ordinarily due 20 days after the issuance of the invoice. Accounts that are unpaid after the due date bear interest at 1.50% per month. Accounts past due more than 30 days are considered delinquent. Interest continues to accrue on delinquent accounts until the account is no longer classified as delinquent.

Delinquent receivables are written off based on individual credit evaluation and specific circumstances of the customer.

During the years ended December 31, 2024 and 2023, credit loss expense related to doubtful accounts receivable, where collectability is not reasonably assured, was approximately $27,000 and $32,000, respectively.

Inventories

Inventories consist of materials and supplies and are stated at the lower of cost or net realizable value. Cost is determined based on average cost.

Utility Plant

Utility plant and equipment are carried at cost. Additions to utility plant and replacements of property are capitalized at cost. Retirements of electric plant or replacements are removed from electric plant accounts at cost and these costs plus cost of removal less salvage are charged to accumulated depreciation. Assets under finance lease obligations are amortized over the shorter of the lease term or respective estimated useful lives. Depreciation of utility plant is provided over the estimated useful life of the respective assets on a straight line basis as follows:

Utility Plant	Years
Distribution plant	25
General plant	33
Equipment	8-15

Maintenance and repairs of property and replacements are charged to expense.

Nonutility Property

Nonutility property consists of land not currently used for utility purposes.

Cash Surrender Value of Life Insurance

The Company has purchased a life insurance policy on a certain individual. Company owned life insurance is recorded at the amount that can be realized under the insurance contract at the balance sheet date, which is the cash surrender value adjusted for other charges or other amounts due that are probable at settlement.

Impairment of Long-Lived Assets

The Company reviews the carrying amount of an asset for possible impairment whenever events or changes in circumstances indicate that such amounts may not be recoverable. If a long-lived asset is tested for recoverability and the undiscounted estimated future cash flows expected to result from the use and eventual disposition of the asset is less than the carrying amount of the asset, the asset cost is adjusted to fair value and an impairment loss is recognized as the amount by which the carrying amount of a long-lived asset exceeds its fair value. No asset impairment was recognized during the years ended December 31, 2024 and 2023.

Goodwill

Goodwill is evaluated annually for impairment or more frequently if impairment indicators are present. The quantitative impairment test consists of calculating the fair value of a reporting unit and comparing it to the carrying amount, including goodwill. The goodwill impairment loss, if any, is measured as the amount by which the carrying amount of a reporting unit, including goodwill, exceeds its fair value. Subsequent increases in goodwill value are not recognized in the consolidated financial statements.

The Company did not record any impairment charges for 2024 or 2023.

Income Taxes

The Company is included in the consolidated federal income tax return filed by C&T. The Company files its own tax return in Pennsylvania. The Company's federal income tax expense is computed using the separate return method for intercorporate tax allocation.

The Company accounts for income taxes in accordance with income tax accounting guidance (Financial Accounting Standards Board ("FASB") Accounting Standards (ASC) 740, *Income Taxes*). The income tax accounting guidance results in two components of income tax expense: current and deferred. Current income tax expense reflects taxes to be paid or refunded for the current period by applying the provisions of the enacted tax law to the taxable income or excess of deductions over revenues. The Company determines deferred income taxes using the liability (or balance sheet) method. Under this method, the net deferred tax asset or liability is based on the tax effects of the differences between the book and tax bases of assets and liabilities, and enacted changes in tax rates and laws are recognized in the period in which they occur. Deferred income tax expense results from changes in deferred tax assets and liabilities between periods. Deferred tax assets are reduced by a valuation allowance if, based on the weight of evidence available, it is more likely than not that some portion or all of a deferred tax asset will not be realized.

Tax positions are recognized if it is more likely than not, based on the technical merits, that the tax position will be realized or sustained upon examination. The term more likely than not means a likelihood of more than 50%; the terms examined and upon examination also include resolution of the related appeals or litigation processes, if any. A tax position that meets the more likely than not recognition threshold is initially and subsequently measured as the largest amount of tax benefit that has a greater than 50% likelihood of being realized upon settlement with a taxing authority that has full knowledge of all relevant information. The determination of whether or not a tax position has met the more likely than not recognition threshold considers the facts, circumstances and information available at the reporting date and is subject to the management's judgment.

The Company recognizes interest and penalties on income taxes as a component of income tax expense.

Regulatory Matters

The Company is subject to the authoritative accounting guidance applicable to rate-regulated organizations. The Pennsylvania PUC has full authority to establish electric rates. Certain items collected in rates have been recorded as regulatory liabilities. These amounts will be recognized as revenue in future periods as costs for which the amounts have been collected are incurred, or when authorized by the Pennsylvania PUC. Certain expenses have been recorded as regulatory assets, and management believes these amounts are probable of future rate recovery.

Revenue Recognition

Revenues from the sale of electricity are recognized as electricity is delivered to customers. Revenues also include amounts receivable from or payable to customers through purchased power clauses, which are adjusted semi-annually.

Costs that are recoverable or refundable in future periods through purchase power recovery are deferred. Costs that are refundable or recoverable in future periods through purchased power recovery rates are subject to audit and approval by the appropriate regulatory body. Changes to the related asset or liability amounts that result from these audits are recorded as a charge to current operations.

The amount and timing of revenue recognition varies based on the nature of the goods or services provided and the terms and conditions of the customer contract. Unbilled revenues of $1,100,909 and $1,020,029 at December 31, 2024 and 2023, respectively, represent amounts delivered through December 31 and not billed to the members until the following month. Customer deposits of $299,385 and $257,839 at December 31, 2024 and 2023, respectively, represent amounts received in advance of services provided. See Note 11 for additional information about the Company's revenue.

For significant financing components, the Company elected a practical expedient, which allows an entity to recognize the promised amount of consideration without adjusting for the time value of money if the contract has a duration of one year or less, or if the reason the contract extended beyond one year is because the timing of delivery of the product is at the customer's discretion. As the Company's contracts are typically less than one year in length and do not have significant financing components, the Company has not presented revenue on a present value basis.

Leases

The Company determines if an arrangement is a lease or contains a lease at inception. Leases result in the recognition of right-of-use (ROU) assets and lease liabilities on the balance sheets. ROU assets represent the right to use an underlying asset for the lease term, and lease liabilities represent the obligation to make lease payments arising from the lease, measured on a discounted basis. The Company determines lease classification as operating or finance at the lease commencement date. The ROU asset for finance leases are included in utility plant in our balance sheets.

At lease commencement, the lease liability is measured at the present value of the lease payments over the lease term. The ROU asset equals the lease liability adjusted for any initial direct costs, prepaid or deferred rent, and lease incentives. The Company has made a policy election to use a risk-free rate (the rate of a zero-coupon U.S. Treasury instrument) for the initial and subsequent measurement of all lease liabilities. The risk-free rate is determined using a period comparable with the lease term.

The lease term may include options to extend or to terminate the lease that the Company is reasonably certain to exercise. Lease expense is generally recognized on a straight-line basis over the lease term.

The Company has elected not to record leases with an initial term of 12 months or less on the balance sheets. Lease expense on such leases is recognized on a straight-line basis over the lease term.

Treasury Stock

Common stock shares repurchased are recorded at cost. Cost of shares retired or reissued is determined using the first-in, first-out method.

Taxes Collected from Customers and Remitted to Governmental Authorities

Sales and gross receipts taxes collected from customers and remitted to governmental authorities are presented in the accompanying statements of income on a net basis.

Note 2. Leases

Nature of Leases

The Company has entered into the following lease arrangements:

Finance Leases

These leases mainly consist of vehicles for the use of the Company. Termination of the leases generally are prohibited unless there is a violation under the lease agreement.

All Leases

The Company has no material related-party leases. The Company's lease agreements do not contain any material residual value guarantees or material restrictive covenants.

Quantitative Disclosures

The lease cost and other required information for the years ended December 31, 2024 and 2023 are:

	2024	2023
Lease cost		
Finance lease cost		
Amortization of right-of-use asset	$ 89,922	$ 76,700
Interest on lease liabilities	14,931	13,927
Short-term lease cost	530	520
Total lease cost	$ 105,383	$ 91,147
Other information		
Cash paid for amounts included in the measurement of lease liabilities		
Financing cash flows from finance leases	$ 64,996	$ 110,652
Weighted-average remaining lease term		
Finance leases	2.38 years	1.78 years
Weighted-average discount rate		
Finance leases	5.51%	4.95%

See Note 6 for future minimum lease payments and reconciliation to the balance sheet at December 31, 2024.

Note 3. Utility Plant

Utility plant consists of the following at December 31:

	2024	2023
Electric plant in service		
Distribution plant	$ 27,120,698	$ 25,895,278
General plant	1,099,144	1,042,086
Equipment	2,582,919	2,572,517
	30,802,761	29,509,881
Construction work-in-progress	119,314	175,214
	30,922,075	29,685,095
Accumulated depreciation	(15,229,615)	(14,740,113)
	$ 15,692,460	$ 14,944,982

Citizens' Electric Company of Lewisburg, Pa.
Notes to Financial Statements
December 31, 2024 and 2023

Note 4. Regulatory Assets and Liability

Regulatory assets consist of the following at December 31:

	2024	2023	Amortization Period
Rate case - 2022	$ 80,155	$ 147,203	3 years
POLR/PJM - 2021	7,533	25,614	3 years
POLR/PJM - 2024	24,893	-	* 3 years
	$ 112,581	$ 172,817	

* Amortization period has not begun

For the years ended December 31, 2024 and 2023, the Company recorded a regulatory liability of $176,954 and $187,771, respectively, for other postretirement benefits that resulted from unrecognized gains. The Company expects to recover the deferred other postretirement benefits consistent with the anticipated income recognition of other postretirement income.

Amortization expense was $86,292 and $106,756 for the years ended December 31, 2024 and 2023, respectively.

Note 5. Line of Credit

The Company has a $4,000,000 revolving line of credit with C&T payable on demand. At December 31, 2024 and 2023, there was $3,300,000 and $2,600,000 borrowed against this line, respectively. Interest varies based on the CoBank quoted variable rate. The rate was 6.39% and 7.41% on December 31, 2024 and 2023, respectively, and is payable monthly.

While the line of credit above is due on demand, the Company utilizes the financing for long-term operating purposes and does not have liquid funds available to repay the balance. The borrowings are available as a result of a line of credit agreement that C&T has with a third party, which is due in July 2026. C&T has no intentions of calling the debt before July 2026.

Citizens' Electric Company of Lewisburg, Pa.
Notes to Financial Statements
December 31, 2024 and 2023

Note 6. Long-Term Debt and Finance Lease Liabilities

	2024	2023
Note payable, C&T, quarterly principal and interest payments of $22,323; interest at 2.37%; collateralized by substantially all Company assets, due June 2025	$ 41,016	$ 121,606
Note payable, C&T, quarterly principal and interest payments of $19,117; interest at 3.925%; collateralized by substantially all Company assets, due December 2041	945,319	983,737
Note payable, C&T, quarterly principal and interest payments of $13,660; interest at 4.175%; collateralized by substantially all Company assets, due December 2041	662,770	689,050
Finance lease liabilities for equipment, requiring monthly principal and interest payments ranging from $620 to $3,280; collateralized by leased equipment, payments due in varying amounts through August 2031	523,224	313,523
	2,172,329	2,107,916
Less current maturities	198,985	202,873
	$ 1,973,344	$ 1,905,043

Aggregate annual maturities of long-term debt and payments on finance lease liabilities at December 31, 2024 are:

	Long-Term Debt	Finance Lease Liabilities
2025	$ 108,359	$ 115,017
2026	70,096	106,153
2027	72,962	112,219
2028	75,945	97,039
2029	79,049	39,361
Thereafter	1,242,694	134,276
	$ 1,649,105	604,065
Less amount representing interest		80,841
Present value of future minimum lease payments		$ 523,224

Transportation equipment under finance lease liabilities is as follows:

	2024	2023
Transportation equipment	$ 728,483	$ 724,293
Accumulated depreciation	(268,878)	(430,125)
	$ 459,605	$ 294,168

C&T has a Master Letter of Credit agreement with National Cooperative Services Corporation. This Letter of Credit is for $7,000,000 and expires October 2029. The Company has the ability to post letters of credit with wholesale electric suppliers under the terms of this agreement. As of December 31, 2024 and 2023, the Company had no outstanding letters of credit.

Note 7. Income Taxes

The provision (credit) for income taxes includes these components:

	2024	2023
Taxes currently payable	$ 121,810	$ 89,977
Deferred income taxes	(53,000)	(166,500)
Income tax expense (benefit)	$ 68,810	$ (76,523)

A reconciliation of income tax expense at the statutory rate to the Company's actual income tax expense (benefit) is shown below:

	2024	2023
Computed at the statutory rate (21%)	$ 83,230	$ 41,974
Increase resulting from		
State income taxes	5,893	(7,427)
Utilization of federal net operating losses	-	(166,500)
Other	(20,313)	55,430
Actual tax expense (benefit)	$ 68,810	$ (76,523)

The tax effects of temporary differences related to deferred taxes shown on the balance sheets were:

	2024	2023
Deferred tax assets		
Allowance for credit losses	$ 9,600	$ 9,700
Post retirement benefits	183,300	202,100
Other	95,700	98,500
	288,600	310,300
Deferred tax liabilities		
Depreciation	(1,894,400)	(1,950,100)
Other	(39,500)	(58,500)
	(1,933,900)	(2,008,600)
Net deferred tax liability	$ (1,645,300)	$ (1,698,300)

At December 31, 2024 and 2023, the Company had no allocation of C&T consolidated unused federal operating loss carryforwards.

Note 8. Pension and Postretirement Plans

Multiemployer Pension Plans

C&T is a member of the National Rural Electric Cooperative Association ("NRECA") Retirement Security Plan ("RS Plan"), a defined benefit pension plan qualified under Section 401 and tax-exempt under Section 501(a) of the Internal Revenue Code. It is a multiemployer plan under the accounting standards. The Plan sponsor's Employer Identification Number is 53-0116145 and the Plan Number is 333.

A unique characteristic of a multiemployer plan compared to a single-employer plan is that all plan assets are available to pay benefits of any plan participant. Separate asset accounts are not maintained for participating employers. This means that assets contributed by one employer may be used to provide benefits to employees of other participating employers.

C&T contributions to the RS Plan in 2024 and 2023 represented less than 5% of the total contributions made to the plan by all participating employers. C&T made contributions to the plan of $3,497,266 and $3,441,415 for years ended December 31, 2024 and 2023, respectively. The Company reimbursed C&T $476,390 and $495,173 for its share of the contributions for the years ended December 31, 2024 and 2023, respectively. There have been no significant changes affecting the comparability of the 2023 and 2023 contributions.

In the RS Plan, a "zone status" determination is not required, and therefore not determined, under the *Pension Protection Act* ("PPA") of 2006. In addition, the accumulated benefit obligations and plan assets are not determined or allocated separately by individual employer. In total, the RS Plan was over 80% funded on January 1, 2024 and 2023, based on the PPA funding target and PPA actuarial value of assets on those dates.

Because the provisions of the PPA do not apply to the RS Plan, funding improvement plans and surcharges are not applicable. Future contribution requirements are determined each year as a part of the actuarial valuation of the plan and may change as a result of plan experience.

C&T is also a member of the NRECA SelectRE Pension Plan. C&T makes a matching contribution of 200% of the employees' contributions up to 2.5% of compensation. The Company reimbursed C&T $89,357 and $85,819 for its share of contributions for the years ended December 31, 2024 and 2023, respectively.

Other Postretirement Benefit Plans

C&T has a postretirement health care plan covering substantially all employees. The Plan is unfunded. The estimated costs that will be paid after retirement are generally being accrued over the employees' active service periods to the dates they are fully eligible for benefits. The Company expects to contribute $32,000 to the Plan in 2025. The following table sets forth the Plan's funded status and the amounts of accrued benefit cost of the C&T plan and the Company's allocation based on an actuarial valuation as of December 31, 2024 and 2023.

Citizens' Electric Company of Lewisburg, Pa.
Notes to Financial Statements
December 31, 2024 and 2023

	2024	2023
C&T's benefit obligation	$ 5,587,931	$ 5,725,208
Company's allocation of benefit obligation	$ 669,250	$ 727,262
C&T's accrued benefit cost	$ 5,587,931	$ 5,725,208
Company's allocation of accrued benefit cost	$ 669,250	$ 727,262
Amounts recognized in the Company's balance sheets		
Current liability, included in accrued expenses	$ 113,386	$ 113,328
Non-current liability	555,864	613,934
	$ 669,250	$ 727,262
C&T's benefit expense	$ 472,064	$ 480,148
Company's allocation of benefit expense	$ 42,284	$ 42,284

The Company uses a December 31 measurement date for the plans. For measurement purposes, a 6.50% annual rate of increase in the per capita cost of covered health care benefits was assumed in 2024. The rate was assumed to decrease gradually to 4.75% in 2030 and remain at that level thereafter.

The benefit obligation was calculated assuming a weighted average discount rate of 5.15% and 5.10% in 2024 and 2023, respectively.

The amount of net gain and net prior service cost expected to be recognized by the Company during 2025 is $7,801 and $-0-, respectively.

Benefits expected to be paid by the Company in each of the next five years and in the aggregate for the five years thereafter are as follows:

2025	$ 113,386
2026	$ 91,048
2027	$ 84,731
2028	$ 87,596
2029	$ 111,884
2030-2034	$ 107,841

Because the Company is subject to regulation in the states in which it operates, it is required to maintain its accounts in accordance with the regulatory authority's rules and regulations, which may differ from other authoritative accounting pronouncements. In those instances, the Company follows the guidance of accounting for regulated operations. Based on prior regulatory practice, and in accordance with the related guidance, the Company recorded an unfunded postretirement obligation, which otherwise would be recognized as other comprehensive income, as a regulatory asset, and expects to recover those costs in rates charged to customers.

Note 9. Related Party Transactions

The Company has a contract for services with C&T to purchase all employee services. The contract automatically renews annually unless terminated by either party.

In the ordinary course of business, the Company's activities involve significant transactions with C&T. The activity between the Company and C&T for the years ended December 31, 2024 and 2023, and the effected account balances at December 31, 2024 and 2023, were as follows:

	2024	2023
Allocation of overhead recorded as operating expense	$ 473,098	$ 434,514
Other costs in accounts receivable - other	$ 43,800	$ 43,800
Accounts payable - related party	$ 229,797	$ 218,124
Accrued vacation liability in accrued expenses	$ 173,588	$ 167,762
Payroll costs paid in advance and included in advances, affiliate	$ 90,700	$ 90,700
Interest expense	$ 280,375	$ 256,329
Acquisition debt expense	$ 556,189	$ 556,189

The Company paid C&T $2,057,330 and $2,000,621 for payroll and $920,419 and $883,969 for benefits in 2024 and 2023, respectively.

Note 10. Commitments and Contingencies

The Company has guaranteed payments on notes payable that are obligations of C&T. At December 31, 2024, the amounts outstanding on these obligations are $5,803,792, of which $1,649,105 is recorded by the Company, see Note 6. These obligations are being repaid in quarterly payments of principal and interest through 2041. The amounts outstanding that are not recorded by the Company are being repaid through acquisition debt expense. The Company would be required to perform under this guarantee if C&T were to default under the notes payable and the bank were to demand the Company's performance.

Note 11. Revenue from Contracts with Customers

Performance Obligations

The Company's revenues are derived primarily from the sale of electric power to customers. Customers consist of commercial, industrial and residential accounts within dedicated territories in and around Lewisburg, Pennsylvania.

Rates charged for electric power sales to customers are established by the Pennsylvania PUC. The Company provides energy and capacity to customers as one stand-ready performance obligation. Electric power revenue is recognized by the Company upon transfer of control of promised services to customers in an amount that reflects the consideration expected to be received in exchange for those services.

The Company transfers control of the electric power to customers at each customer's meter point and the customers simultaneously receive and consume the benefits of the energy provided. Electric power provided to customers is accounted for as a series of performance obligations. Progress towards completion is measured using the output method [kilowatt hour (kwh) received by the customer], meter readings are taken at the end of

the month for billing purposes, the quantity of energy transferred is determined after the meter readings. Payments from customers are received in accordance with each customer's contract, which is ordinarily 20 days from the invoice date.

Revenue associated with the electric power performance obligation to customers are recorded as sales of electric energy and capacity to customers in the accompanying statements of income.

The Company has determined that the nature, amount, timing and uncertainty of revenue and cash flows are primarily affected by factors that impact demand.

Contract Balances

The following table provides information about the Company's accounts receivable and customer deposits from contracts with customers:

	2024	2023
Accounts receivable - customers, beginning of year	$ 1,456,491	$ 1,470,719
Accounts receivable - customers, end of year	$ 1,173,451	$ 1,456,491
Unbilled revenues, beginning of year	$ 1,020,029	$ 1,357,715
Unbilled revenues, end of year	$ 1,100,909	$ 1,020,029
Customer deposits, beginning of year	$ 257,839	$ 223,974
Customer deposits, end of year	$ 299,385	$ 257,839

Note 12. Subsequent Events

Subsequent events have been evaluated through March 12, 2025, which is the date the financial statements were available to be issued.

Supplementary Information

Citizens' Electric Company of Lewisburg, Pa.
Comparative Financial Statistics
Years Ended December 31, 2024, 2023, 2022, 2021, and 2020

	2024	2023	2022	2021	2020
Income Statistics					
Operating revenues	$ 16,378,412	$ 20,412,472	$ 17,029,076	$ 13,759,137	$ 13,654,824
Power purchased	9,682,484	13,730,344	10,987,752	7,890,338	8,165,083
Other operating expenses	5,466,540	5,720,391	5,139,130	4,810,283	4,751,385
Operating income	1,229,388	961,737	902,194	1,058,516	738,356
Other expense, net	(833,055)	(761,859)	(687,864)	(679,226)	(701,008)
Income before income taxes	396,333	199,878	214,330	379,290	37,348
Provision (credit) for income taxes	68,810	(76,523)	105,286	238,526	80,248
Net income (loss)	$ 327,523	$ 276,401	$ 109,044	$ 140,764	$ (42,900)
Balance Sheet Statistics					
Working capital	$ (1,715,164)	$ (1,240,372)	$ (466,530)	$ 104,966	$ 596,021
Total Stockholder's Equity	$ 13,982,593	$ 13,697,370	$ 13,461,369	$ 13,384,425	$ 13,263,961
Per Share Statistics					
Basic earnings per share	$ 2.43	$ 2.05	$ 0.81	$ 1.05	$ (0.32)
Book Value Per Share	$ 103.80	$ 101.69	$ 99.93	$ 99.36	$ 98.47

Citizens' Electric Company of Lewisburg, Pa.
Utility Plant and Accumulated Depreciation
Year Ended December 31, 2024

Acct. No.	Account	Utility Plant: Cost January 1, 2024	Additions	Retirements	Cost December 31, 2024	Accumulated Depreciation: Balance January 1, 2024	Retirements	Cost of Removals	Salvage Received	Depreciation Rate	Depreciation Amount	Balance December 31, 2024
	Distribution plant											
302	Franchises and consents	27	-	-	27	255	-	-	-	0.000	-	$ 255
360	Land and land rights	17,040	1,254	-	18,294	-	-	-	-	0.000	-	-
362	Station equipment	792,280	-	15,868	776,412	761,560	15,868	2,196	-	4.000	2,969	746,465
364	Poles, towers and fixtures	4,317,240	160,455	31,694	4,446,001	3,128,994	31,694	56,949	3,912	4.125	184,754	3,229,017
365	Overhead conductors and devices	8,043,524	462,968	66,108	8,440,384	1,985,151	66,108	97,175	6,382	4.000	328,730	2,156,980
367	Underground conductors and devices	3,485,764	180,115	2,624	3,663,255	2,142,257	2,624	2,775	231	4.000	141,732	2,278,821
368	Line transformers	2,950,070	140,154	32,422	3,057,802	2,251,693	32,422	-	-	4.000	120,120	2,339,391
369	Services	4,130,180	239,595	23,910	4,345,865	1,776,639	23,910	35,011	5,094	4.000	167,472	1,890,284
370	Meters	1,478,201	260,127	53,519	1,684,809	(46,144)	53,519	-	-	4.000	63,056	(36,607)
373	Street lighting and signal systems	680,950	20,177	11,509	689,618	59,572	11,509	11,873	509	4.000	46,482	83,181
	General plant											
390	Structures and improvements, general plant	721,358	57,058	-	778,416	584,566	-	-	-	3.000	5,379	589,945
301	Organization	968	-	-	968	-	-	-	-	0.000	-	-
303	Intangible asset - EDI Equipment	319,218	-	-	319,218	319,215	-	-	-	0.000	-	319,215
391	Office furniture and equipment	595,278	20,301	170,748	444,831	428,049	170,748	-	-	8.000	41,164	298,465
392	Transportation equipment	1,294,630	278,419	151,118	1,421,931	890,038	151,117	-	-	12.500	113,641	852,562
393	Stores equipment	39,241	-	-	39,241	36,479	-	-	-	6.666	731	37,210
394	Tools, shop and garage equipment	128,054	9,237	-	137,291	77,162	-	-	-	10.000	8,375	85,537
395	Laboratory equipment	66,746	-	-	66,746	39,840	-	-	-	6.666	4,184	44,024
396	Power operated equipment	11,845	-	-	11,845	13,508	-	-	-	12.500	-	13,508
397	Communication equipment	405,497	23,742	1,202	428,037	282,702	1,202	-	-	6.666	9,256	290,756
398	Miscellaneous equipment	31,770	-	-	31,770	8,577	-	-	-	6.666	2,029	10,606
		29,509,881	1,853,602	560,722	30,802,761	$ 14,740,113	$ 560,721	$ 205,979	$ 16,128		1,240,074	$ 15,229,615
	Construction work-in-process	175,214	-	55,900 (N)	119,314					Less charged to clearing	113,641	
		$ 29,685,095	$ 1,853,602	$ 616,622	$ 30,922,075					Total depreciation	$ 1,126,433	

(N) Net Decrease

Citizens' Electric Company of Lewisburg, Pa.
Accrued Taxes, Net
December 31, 2024 and 2023

	2024	2023
State gross receipts tax	$ (86,455)	$ (372,013)
State public utility realty tax	13,123	16,853
State income tax	(1,207)	16,185
Federal income tax	36,830	28,248
Other	(651)	3,645
	$ (38,360)	$ (307,082)

Citizens' Electric Company of Lewisburg, Pa.
Operating Revenues and Taxes, Other Than Income
Years Ended December 31, 2024 and 2023

	2024	2023
Operating Revenues		
Residential sales	$ 11,286,366	$ 14,080,536
Commercial and industrial sales	4,825,636	6,049,133
Public street and highway lighting sales	167,186	175,158
Customers' forfeited discounts	28,404	39,008
Rent from electric property	56,782	53,698
Other electric revenues	14,038	14,939
	$ 16,378,412	$ 20,412,472
Taxes, Other Than Income		
State gross receipts	$ 894,130	$ 1,222,013
State Pennsylvania Utility Commission assessment	63,038	40,815
State use tax	7,604	2,233
State public utility realty tax	13,654	20,000
	$ 978,426	$ 1,285,061

Citizens' Electric Company of Lewisburg, Pa.
Distribution, Operation; Distribution, Maintenance;
Customer Accounts and General and Administrative Expenses
Years Ended December 31, 2024 and 2023

	2024	2023	Increase (Decrease)	% Change
Distribution, Operation Expenses				
Station	$ 5,257	$ 20,968	$ (15,711)	-74.93%
Overhead lines	171,932	164,711	7,221	4.38%
Underground lines	54,098	77,898	(23,800)	-30.55%
Street lighting and signal system	12,169	8,095	4,074	50.33%
Meters	24,043	25,262	(1,219)	-4.83%
Engineering	147,493	139,449	8,044	5.77%
Customer installations	45,793	39,845	5,948	14.93%
Miscellaneous distribution	520,551	501,982	18,569	3.70%
Rents	530	520	10	1.92%
	$ 981,866	$ 978,730	$ 3,136	0.32%
Distribution, Maintenance Expenses				
Station equipment	$ 25,131	$ 2,202	$ 22,929	1041.28%
Overhead lines	558,562	563,526	(4,964)	-0.88%
Underground lines	13,331	16,531	(3,200)	-19.36%
Line transformers	31,969	85,912	(53,943)	-62.79%
Street lighting and signal system	15,914	22,847	(6,933)	-30.35%
	$ 644,907	$ 691,018	$ (46,111)	-6.67%
Customer Accounts Expenses				
Meter reading	$ 26,340	$ 25,085	$ 1,255	5.00%
Customer records and collection	483,000	474,977	8,023	1.69%
Uncollectible accounts	27,331	31,906	(4,575)	-14.34%
	$ 536,671	$ 531,968	$ 4,703	0.88%
General and Administrative Expenses				
Salaries and benefits	$ 699,187	$ 749,198	$ (50,011)	-6.68%
Administrative	154,815	104,651	50,164	47.93%
Outside services employed	40,008	47,389	(7,381)	-15.58%
Insurance	11,188	11,431	(243)	-2.13%
Injuries and damage	27,339	27,561	(222)	-0.81%
General advertising	655	1,061	(406)	-38.27%
Miscellaneous general	93,096	89,884	3,212	3.57%
Directors' committee	16,849	14,352	2,497	17.40%
Maintenance of general plant	155,100	121,914	33,186	27.22%
	$ 1,198,237	$ 1,167,441	$ 30,796	2.64%

McNees Wallace & Nurick LLC
100 Pine Street
P.O. Box 1166
Harrisburg, PA 17108-1166

Adeolu A. Bakare
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abakare@mcneeslaw.com

December 19, 2024

VIA ELECTRONIC FILING

Rosemary Chiavetta, Secretary
Pennsylvania Public Utility Commission
Commonwealth Keystone Building
400 North Street, 2nd Floor
Harrisburg, PA 17120

RE: Citizens' Electric Company of Lewisburg, PA
Supplement No. 170 to Tariff Electric PA. P.U.C. No. 14 (State Tax Adjustment Surcharge Recalculation); Docket No. _____

Dear Secretary Chiavetta:

Attached for filing with the Commission is Citizens' Electric Company of Lewisburg, PA's ("Citizens'" or "Company") Supplement No. 170 to Tariff Electric-Pa. P.U.C. No. 14 ("Supplement No. 170"). Supplement No. 170 reflects a recalculation of the State Tax Adjustment Surcharge ("STAS"). Supplement No. 170 contains an issued date of December 19, 2024, and an effective date of January 1, 2025. This complies with the ten (10) day notice period for STAS modifications specified on page 37 of the Company's tariff.

This filing adjusts Citizens' STAS to refund a prior period overcollection and to reflect changes in the Company's Corporate Net Income Tax and Utility Realty Tax. The documents supporting the Company's recalculation are set forth in Tab A, Attachments A, B, C, D, E, and F (computation of STAS for period January 1, 2025, through December 31, 2025). For completeness, a copy of proposed Supplement No. 170 is attached at Tab B. The supporting documents at Tab A demonstrate that the Company's STAS rate will decrease from a surcredit of -0.0126% to a surcredit of -0.0255%, effective January 1, 2025. See Tab A.

If you have any questions regarding the documents, please feel free to contact the undersigned. Thank you.

Very truly yours,

Adeolu A. Bakare
MCNEES WALLACE & NURICK LLC
Counsel to Citizens' Electric Company of Lewisburg, PA

AAB/leh
Enclosures
c: Certificate of Service
Erin Laudenslager, Bureau of Technical Utility Services (via E-mail)
Lori Burger, Bureau of Audits (via E-mail)

CERTIFICATE OF SERVICE

I hereby certify that I am this day serving a true copy of the foregoing document upon the participants listed below in accordance with the requirements of Section 1.54 (relating to service by a participant).

VIA E-MAIL

NazAarah Sabree
Small Business Advocate
Commonwealth of Pennsylvania
Office of Small Business Advocate
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555 Walnut Street, 1st Floor
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Harrisburg, PA 17101
ra-oca@paoca.org

Adeolu A. Bakare

Counsel to Citizens' Electric Company of Lewisburg, PA

Dated this 19th day of December, 2024, in Harrisburg, Pennsylvania.

Supplement No. 170
to
Electric-Pa. P.U.C. No. 14

CITIZENS' ELECTRIC COMPANY OF LEWISBURG

RULES AND REGULATIONS AND RATE SCHEDULES FOR ELECTRIC SERVICE

IN

LEWISBURG BOROUGH; BUFFALO, EAST BUFFALO AND KELLY TOWNSHIPS, UNION COUNTY, PENNSYLVANIA

Issued December 19, 2024

Effective January 1, 2025

Issued by
NATHAN JOHNSON, PRESIDENT & CEO
1775 Industrial Boulevard
Lewisburg, PA 17837

N O T I C E !

THIS SUPPLEMENT MAKES {{CHANGES}} TO EXISTING RATES
See Page No. 2

Supplement No. 170 to
Electric-Pa. P.U.C. No. 14

CITIZENS' ELECTRIC COMPANY OF LEWISBURG

One-Hundred-Fifty-Sixth Revised Page No. 2
Cancelling
One-Hundred-Fifty-Fifth Revised Page No. 2

LIST OF CHANGES MADE IN THIS SUPPLEMENT

Page 37:

Supplement No. 170 sets the State Tax Adjustment Surcharge ("STAS") at -0.0255%, effective on January 1, 2025. This recalculation is necessary to refund a prior period overcollection and to reflect changes in the Company's Corporate Net Income Tax and Utility Realty Tax.

Supplement No. 170 to
Electric-Pa. P.U.C. No. 14

CITIZENS' ELECTRIC COMPANY OF LEWISBURG

One-Hundred-Fifty-Fifth Revised Page No. 3
Cancelling
One-Hundred-Fifty-Fourth Revised Page No. 3

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(C) Indicates Change

Supplement No. 170 to
Electric-Pa. P.U.C. No. 14

CITIZENS' ELECTRIC COMPANY OF LEWISBURG

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Issued December 19, 2024

Effective January 1, 2025

Supplement No. 170 to
Electric-Pa. P.U.C. No. 14
CITIZENS' ELECTRIC COMPANY OF LEWISBURG Thirty-Eighth Revised Page No. 37
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STATE TAX ADJUSTMENT SURCHARGE

In addition to the charges provided in this tariff, a surcredit of -0.0255% will apply to all bills for service rendered on or after January 1, 2025. (D) (C)

The State Tax Adjustment Surcharge will be recomputed using the elements prescribed by the Commission whenever the Company experiences a material change in any of the taxes used in calculation of the surcharge. Such recalculation will be submitted to the Commission within 10 days after the occurrence of the event which occasions such re-computation. If the recomputed surcharge is less than the one in effect the utility will, or if the recomputed surcharge is more than the one in effect the utility may, submit such re-computation a tariff or supplement to reflect such recomputed surcharge. The effective date of such tariff or supplement shall be ten days after filing. Any charges or credits in the surcharge shall be rolled into the base rates in the Company's next base rate proceeding.

(D) Indicates Decrease (C) Indicates Change

CITIZENS' ELECTRIC COMPANY OF LEWISBURG, PA

Computation of State Tax Adjustment Surcredit
for the Period January 1, 2025 through December 31, 2025

			Amount	Attachment Number
1	Capital Stock Tax	$	-	
2	Corporate Net Income Tax	$	(10,825)	**F**
3	Utility Realty Tax	$	548	**A**
4	Gross Receipts Tax	$	-	
5	Total of Lines 1, 2, 3, and 4	$	(10,276)	
6	PURTA Surcharge Rate Adjustment	$	-	**B**
7	Revenue Neutral Reconciliation (RNR) Tax Adjustment	$	-	**C**
8	Total of Lines 5, 6, and 7	$	(10,276)	
9	Line 8 divided by complement of Gross Receipts Tax Rate (.941)	$	(10,921)	
10	STAS reconciliation for period January 1, 2024 through December 31, 2024	$	5,652	**D**
11	Total of Lines 9 and 10	$	(5,268)	
12	Gross Intrastate Operating Revenues derived from service under rates subject to the jurisdiction of the Pa. Public Utility Commission for the application period January 1, 2023 through December 31, 2023 with adjustments (Page 11)	$	20,677,469	**E**
13	Surcredit rate to be applied for the period January 1, 2025 through December 31, 2025 (Line 11 divided by Line 12)		-0.0255%	

ATTACHMENT A

CITIZENS' ELECTRIC COMPANY OF LEWISBURG, PA

Calculation of Surcredit Rate 1/01/25 - 12/31/25

Public Utility Realty Tax Assessment (PURTA)

1	7/31/2024 Notice of Determination Adjustments: State Tax Property Value at December 31, 2023	$ 1,078,272		
2	Pa. Public Utility Realty Tax (Based on applied rate of 23.7970 mills x Line 1)		$ 25,660	
3	8/1/2023 Notice of Determination Adjustments: State Tax Property Value at December 31, 2022	$ 1,010,880		
4	Pa. Public Utility Realty Tax (Based on applied rate of 24.8531 mills x Line 1)		$ 25,124	
5	2025 PURTA Adjustment (Line 2 minus Line 4)			$ 536

continued on page 2A

ATTACHMENT A

CITIZENS' ELECTRIC COMPANY OF LEWISBURG, PA

Calculation of Surcredit Rate 1/01/25 - 12/31/25

Public Utility Realty Tax Assessment (PURTA)

1	Continued from page 2 (Line 5)		$ 536
	Notice of Determination Adjustments:	**7/31/2024**	
2	2019 PURTA		
	Liability Adjustment	$ 1	$ 1
3	2020 PURTA		
	Liability Adjustment	$ 1	$ 1
4	2021 PURTA		
	Liability Adjustment	$ 1	$ 1
5	2022 PURTA		
	Liability Adjustment	$ 9	$ 9
7	Total 2025 PURTA Adjustment (Lines 1 through 19)		$ 548

ATTACHMENT B

CITIZENS' ELECTRIC COMPANY OF LEWISBURG, PA

Calculation of Surcredit Rate 1/01/25 - 12/31/25

Public Utility Realty Tax Assessment Surcharge

Tax Year Ending 2025

Projected taxable revenues for period January 1, 2025 to December 31, 2025 (Page 13)	$ 17,931,312
PURTA surcharge rate as established by the Department of Revenue and published in the Pennsylvania Bulletin on September 21, 2024	0.0000
2025 PURTA Surcharge	$ -

ATTACHMENT C

CITIZENS' ELECTRIC COMPANY OF LEWISBURG, PA

Calculation of Surcredit Rate 1/01/25 - 12/31/25

Revenue Neutral Reconciliation (RNR) Tax Adjustment
Applicable to Gross Receipts Tax

Tax Year Ending 2025

Projected taxable revenues for Pa. gross receipts tax for period January 1, 2025 to December 31, 2025 (Page 13)	$	17,931,312
RNR tax rate adjustment as established by the Department of Revenue and published in the Pennsylvania Bulletin on Dec. 1, 2001		0.000
Projected increase in applicable 2025 gross receipts tax liability based on RNR tax rate adjustment	$	-

ATTACHMENT D

CITIZENS' ELECTRIC COMPANY OF LEWISBURG, PA

Reconciliation of State Tax Adjustment Surcharge
for the Period ending December 31, 2024

		Amount	Schedule Number
1	Capital Stock Tax	$ -	**1**
2	Corporate Net Income Tax	$ -	
3	Utility Realty Tax	$ 244	**2**
4	Gross Receipts Tax	$ -	
5	Total of Items 1, 2, 3, and 4	$ 244	
6	PURTA Surcharge Rate Adjustment	$ -	**3**
7	Revenue Neutral Reconciliation (RNR) Tax Adjustment	$ -	**4**
8	Total of Lines 5, 6, and 7	$ 244	
9	Line 8 divided by complement of Gross Receipts Tax Rate (.941)	$ 259	
10	STAS reconciliation for period Jan. 1, 2023 through December 31, 2023	$ 3,391	
11	Total of Lines 9 and 10	$ 3,650	
12	STAS Revenue Collections (Page 11)	$ (2,002)	**5**
13	(Over)/Under Collection (Line 11 minus Line 12)	$ 5,652	

ATTACHMENT E

CITIZENS' ELECTRIC COMPANY OF LEWISBURG, PA

Schedule 1

Reconciliation of State Tax Adjustment Surcharge
for the Period ending December 31, 2023

****Capital Stock Tax Phased out in 2016****
Capital Stock Tax @ .00 mills effective 1/1/17

1	Tax Base -- year 2017 see attached page 2 of 2017 PA Tax Report		$ -
2	Tax Millage in basic rates (2020)	0.000000	
3	Tax Millage effective 1/1/20	0.000000	
4	Effective Rate Increase (Decrease) (Line 2 minus Line 3)		0.000000
5	Total Capital Stock/Franchise Tax Increase (Decrease) (Line 1 X Line 4)		$ -

ATTACHMENT E

CITIZENS' ELECTRIC COMPANY OF LEWISBURG, PA

Schedule 2

Reconciliation of State Tax Adjustment Surcharge for the Period ending December 31, 2024

Public Utility Realty Tax Assessment (PURTA)

1	8/1/2023 Notice of Determination Adjustments: State Tax Property Value at December 31, 2022	$ 1,010,880		
2	Pa. Public Utility Realty Tax (Based on applied rate of 24.8531 mills x Line 1)		$ 25,124	
3	8/1/2022 Notice of Determination Adjustments: State Tax Property Value at December 31, 2021	$ 898,560		
4	Pa. Public Utility Realty Tax (Based on applied rate of 27.1851 mills x Line 1)		$ 24,427	
5	2024 PURTA Adjustment (Line 2 minus Line 4)			$ 696

continued on page 7A

ATTACHMENT E

CITIZENS' ELECTRIC COMPANY OF LEWISBURG, PA

Schedule 2

Public Utility Realty Tax Assessment (PURTA)

1	Continued from page 7 (Line 5)		$ 696
	Notice of Determination Adjustments:	**8/1/2023**	
2	2018 PURTA		
	Liability Adjustment	$ (58)	$ (58)
3	2019 PURTA		
	Liability Adjustment	$ (54)	$ (54)
4	2020 PURTA		
	Liability Adjustment	$ (62)	$ (62)
5	2021 PURTA		
	Liability Adjustment	$ (278)	$ (278)
7	Total 2025 PURTA Adjustment (Lines 1 through 18)		$ 244

ATTACHMENT E

CITIZENS' ELECTRIC COMPANY OF LEWISBURG, PA

Schedule 3

Reconciliation of State Tax Adjustment Surcharge
for the Period ending December 31, 2024

Public Utility Realty Tax Assessment Surcharge

Tax Year Ending 2024

Taxable revenues for Pa. gross receipts tax for period January 1, 2024 to December 31, 2024 (Page 12)	$ 16,472,793	
PURTA surcharge rate as established by the Department of Revenue and published in the Pennsylvania Bulletin on September 30, 2023	0.0000	
2024 PURTA Surcharge		$ -

ATTACHMENT E

**Reconciliation of State Tax Adjustment Surcharge
for the Period ending December 31, 2024**

Schedule 4

**Reconciliation of State Tax Adjustment Surcharge
for the Period ending December 31, 2024**

**Revenue Neutral Reconciliation (RNR) Tax Adjustment
Applicable to Gross Receipts Tax**

Tax Year Ending 2024

1	Taxable revenues for Pa. gross receipts tax for period January 1, 2024 to December 31, 2024 (Page 12)	$ 16,472,793	
2	RNR tax rate adjustment as established by the Department of Revenue and published in the Pennsylvania Bulletin on December 1, 2001	$ -	
3	Projected increase in applicable 2024 gross receipts tax liability based on RNR tax rate adjustment		$ -

ATTACHMENT E

CITIZENS' ELECTRIC COMPANY OF LEWISBURG, PA

Schedule 5

STAS Revenue Collected/(Refunded)
for period January 1, 2024 through December 31, 2024

Month		**Tax Surcharge**
January	$	(238)
February	$	(230)
March	$	(187)
April	$	(173)
May	$	(144)
June	$	(139)
July	$	(157)
August	$	(162)
September	$	(142)
October	$	(124)
November	$	(139)
December (estimate)	$	(167)
Total STAS Collected/(Refunded)	$	(2,002)

ATTACHMENT E

CITIZENS' ELECTRIC COMPANY OF LEWISBURG, PA

OPERATING REVENUES

Revenue billed for 12 month audited period ending December 31, 2023

Residential	$	14,311,770	
Commercial & Industrial	$	6,148,473	
Public Street & Highway Lighting	$	175,158	
Customer' Forfeited Discounts	$	39,008	
Total Gross Electric Revenue including Tax Surcharge *			$ 20,674,409
Less: Tax Surcharge collected			$ (3,060)
Total Electric Revenue projected for application period January 1, 2025 through December 31, 2025			$ 20,677,469

*Revenue does not include unbilled revenue.

CITIZENS' ELECTRIC COMPANY OF LEWISBURG, PA

Revenues Billed from Service Under Rates
for the Application Period January 1, 2024 to December 31, 2024

Month	MWh Sales	Base Rate Revenue*	Forfeited Discounts	Total Revenues
January	14,996	$ 1,907,331	$ 3,069	$ 1,910,400
February	15,679	$ 1,841,295	$ 3,455	$ 1,844,750
March	12,777	$ 1,494,763	$ 2,952	$ 1,497,715
April	12,029	$ 1,387,623	$ 3,034	$ 1,390,657
May	10,306	$ 1,150,387	$ 2,734	$ 1,153,121
June	11,562	$ 1,132,092	$ 2,147	$ 1,134,239
July	12,931	$ 1,284,549	$ 1,846	$ 1,286,395
August	13,602	$ 1,322,176	$ 1,906	$ 1,324,082
September	12,094	$ 1,156,689	$ 2,140	$ 1,158,829
October	10,234	$ 1,013,663	$ 1,884	$ 1,015,547
November	11,102	$ 1,127,621	$ 1,385	$ 1,129,006
December (estimate)	13,926	1,625,416	2,636	$ 1,628,052
Totals	151,238	$ 16,443,605	$ 29,188	$ 16,472,793

*Does not include unbilled revenue.

CITIZENS' ELECTRIC COMPANY OF LEWISBURG, PA

Projected Revenues Billed from Service Under Rates
for the Application Period January 1, 2025 to December 31, 2025

Month	MWh Sales	Base Rate Revenue*	Forfeited Discounts	Projected Revenues
January	15,787	$ 1,803,378	$ 4,079	$ 1,807,457
February	16,306	$ 1,862,663	$ 4,079	$ 1,866,742
March	13,609	$ 1,554,585	$ 4,079	$ 1,558,664
April	12,590	$ 1,438,184	$ 4,079	$ 1,442,263
May	10,974	$ 1,253,589	$ 4,079	$ 1,257,668
June	11,778	$ 1,345,429	$ 4,079	$ 1,349,508
July	13,043	$ 1,489,930	$ 4,079	$ 1,494,009
August	13,331	$ 1,522,829	$ 4,079	$ 1,526,908
September	11,982	$ 1,368,732	$ 4,079	$ 1,372,811
October	10,657	$ 1,217,378	$ 4,079	$ 1,221,457
November	12,126	$ 1,385,182	$ 4,079	$ 1,389,261
December	14,361	$ 1,640,486	$ 4,079	$ 1,644,565
Totals	156,547	$ 17,882,364	$ 48,948	$ 17,931,312

*Does not include unbilled revenue.

ATTACHMENT F

CITIZENS' ELECTRIC COMPANY OF LEWISBURG, PA

Pursuant to the Pennsylvania Utility Commission's State Tax Adjustment Surcharge (STAS) Procedures.

			Distribution Only
1	Net Operating Income Excluding Income Taxes		$1,258,282
2			
3	Synchronized interest expense:		
4	Rate base		12,825,060
5	Less: CWIP		3,564
6	Rate base for interest compuation		12,821,496
7	Weighted Cost of debt		2.397%
8	Synchronized interest expense		307,331
9	Taxable income before depreciation tax adjustments		950,951
10			
11	Pennsylvania depreciation adjustment:		
12	Tax depreciation (using DDB method)		(897,824)
13	Book depreciation		1,029,328
14	Pennsylvania depreciation adjustment		131,504
15	Pennsylvania taxable income		1,082,455
16	Regulatory Pennsylvania income tax expense	8.99%	97,313
		7.99%	86,488
17	Regulatory Pennsylvania Income Tax Expense Credit		(10,825)
	Monthly CNIT Credit		(902)

Exhibit-KAS-3

		Historic Year Actual Ended 12/31/21	Historic Year Actual Ended 12/31/22	Historic Year Actual Ended 12/31/23	Historic Year Actual Ended 12/31/24	Future Test Year Ended 12/31/25	Actual Ended 03/31/25	Fully Projected Future Test Year Ended 12/31/26
Distribution Expenses:								
580	Operations Supt & Eng	131,110	157,885	139,449	147,492	151,142	40,688	154,958
582	Station Expense	13,239	1,657	20,968	5,258	13,979	1,026	14,046
583/584	Overhead Line Expense	207,522	132,517	242,610	226,033	234,927	41,557	242,072
585	Street Lighting Expense	7,724	2,731	8,095	12,169	5,025	3,767	5,137
586	Meter Expense	19,012	32,554	25,262	24,042	48,958	(5,635)	50,712
587	Customer Installation Expense	60,744	35,338	39,845	41,115	53,765	9,122	56,416
588	Miscellaneous Distribution Exp	293,481	321,029	395,055	455,104	486,415	130,933	495,254
589	Rents	499	509	520	530	525	-	525
	Total Operating Expense	733,331	684,220	871,804	911,743	994,735	221,458	1,019,120
590	Maint Supv & Eng	-	-	-	-	-	-	-
591	Maint of Structures	-	-	-	-	-	-	-
592	Maintenance of Station Equipment	5,435	5,256	2,202	25,133	-	-	17,209
593	Maintenance of Overhead Line	481,913	499,708	563,525	558,565	-	161,323	826,836
594	Mainteneance of Underground Lines	4,246	5,304	16,532	13,331	Maint. O'hd. Line	1,240	14,827
595	Maintain Line Transformers	18,983	16,165	85,912	31,968	Vegetation Ma	626	27,468
596	Maint. Street Light & Signal Expense	9,879	19,558	22,847	15,914	-	4,896	24,187
597	Maint of Misc. Distrib Plant	367	-	-	-	Maint. Line Trans	-	-
	Total Maintenance Expense	520,823	545,991	691,018	644,911	-	168,085	910,527
	Total Operating & Maintenance Exp.	1,254,154	1,230,211	1,562,822	1,556,654	994,735	389,543	1,929,647
Customer Accounting & Collection Expenses:								
902	Meter Reading Expense	13,633	24,086	25,085	26,338	26,000	6,717	169,939
903	Customer records & Collections Exp	442,188	441,004	474,977	483,001	486,259	110,716	-
904	Uncollectible Accounts	31,941	43,106	31,906	27,330	30,000	6,177	-
	Total Customer Acctg & Coll. Exp	487,762	508,196	531,968	536,669	542,259	123,610	169,939
Sales Expense, Public Relations								
908-913	Safety and Communications	-	-	-	-	-	-	-
Administrative & General Expenses:								
920	Administrative & General Salaries	607,671	631,219	742,994	700,832	732,830	190,784	-
921	Office Supplies & Expenses	206,061	222,508	243,492	145,653	246,988	67,313	-
923	Outside Services Employed	5,525	24,549	47,103	40,008	37,000	41,225	-
924	Property Insurance	11,112	11,320	11,431	11,190	11,059	2,766	-
925	Injuries & Damages	26,647	26,694	27,561	27,341	28,907	6,768	-
926	Employee Pensions & Benefits	1,756	14,579	6,204	7,497	8,500	1,494	-
928	Regulatory Commission Expense	108,668	108,672	105,515	70,128	88,208	17,532	-
930	Miscellaneous General Expense	94,585	101,474	105,300	110,600	110,891	25,885	447,964
931	Rents	-	-	-	-	-	-	-
932	Maintenance of General Property	163,227	225,917	121,914	155,101	164,713	66,732	165,455
	Total Administrative & General Exp.	1,225,252	1,366,932	1,411,514	1,268,350	1,429,095	420,499	613,419
	Total Operating & Maintenance Exp.	2,967,168	3,105,339	3,506,304	3,361,673	2,966,089	933,652	2,713,005
	Check to C1-1	*$2,967,168*	*$3,105,339*	*$3,506,304*	*$3,361,673*	*$3,715,057*		*$4,102,061*

Exhibit-KAS-4

	Historic Actual	Historic Actual	Historic Actual	Historic Actual	Future Test Year	Actual	Fully Projected Future Test Year
	Balance 12/31/21	Balance 12/31/22	Balance 12/31/23	Balance 12/31/24	Forecast 12/31/25	03/31/25	Forecast 12/31/26
Depreciable Plant:							
360 Land & Land Rights	15,708	16,191	17,040	19,360	19,360	18,414	20,458
361 Structures and Improvements	-	-	-	-	-		-
362 Station Equipment	792,280	792,280	792,280	776,412	776,412	776,412	776,412
364 Poles, Tower & Fixtures	4,113,235	4,252,749	4,317,240	4,446,001	4,612,432	4,728,592	4,934,235
365 Overhead Conductors & Devices	7,654,591	8,156,039	8,043,524	8,440,384	9,142,814	8,523,796	9,866,317
366 Underground Conduit	3,228,218	3,398,864	3,485,764	3,663,255	3,860,336	3,711,779	4,063,329
368 Line Transformers	2,788,156	2,898,891	2,950,070	3,057,802	3,241,585	3,049,538	3,430,881
369 Services	3,879,146	4,046,185	4,130,180	4,345,865	4,643,243	4,384,015	4,949,542
370 Meters	2,007,239	2,161,712	1,478,201	1,684,809	1,740,941	1,720,416	1,798,757
373 Steet Lighting & Signal Systems	750,787	783,253	680,950	689,618	753,904	701,082	820,118
Total Distribution Plant	25,229,360	26,506,164	25,895,249	27,123,506	28,791,027	27,614,044	30,660,049
General Plant							
390.1 Structures & Improvements, Office	647,963	668,746	721,358	778,416	813,880	778,958	874,824
390X General - Fully Depreciated	764,864	764,864	319,218	319,218	319,218	319,218	319,218
391 Office Furniture & Equipment	341,801	442,747	595,278	444,831	482,109	444,271	546,167
392 Transportation Equipment	941,166	1,134,909	1,294,630	1,421,931	1,846,931	1,421,846	2,232,931
394 Tools, Shop & Garage Equipment	69,432	70,820	128,054	137,291	143,816	139,062	150,340
395 Laboratory & Stores Equipment	70,969	70,969	105,987	105,987	105,987	117,833	105,987
397 Communication Equipment	272,313	272,313	405,497	428,037	428,037	428,135	428,037
398 Miscellaneous Equipment	18,110	18,110	43,615	43,615	47,090	31,770	50,566
Intangible Plant, Organization	-	-	995	995	995	995	995
301 Intangible Plant, EDI	319,218	342,651	-	-	-	-	-
Total General Plant	3,445,836	3,786,129	3,614,632	3,680,321	4,188,063	3,682,088	4,709,065
Total Plant In Service	28,675,196	30,292,293	29,509,881	30,803,827	32,979,090	31,296,132	35,369,114
Check to C3	*$28,675,196*	*$30,292,293*	*$29,509,881*	*$30,802,761*	*$32,979,090*		*$35,369,114*

FTY & FPFTY Wage & Salary Increase Detail

Citizens' Electric Company

	2024	2025		2026	
	$$$	$$$	% of Total Increase	$$$	% of Total Increase
Total Budgeted Wages:	$ 1,770,641	$ 1,898,017		$ 2,028,881	
Total Wage Increase:		$ 127,537		$ 151,783	
Annual Base Comp. Adj.:		$ 53,194	41.7%	$ 48,081	31.7%
Market:		$ 31,132	24.4%	$ 21,570	14.2%
Merit:		$ 12,209	9.6%	$ 40,868	26.9%
New Hire:		$ 26,967	21.1%	$ 27,641	18.2%

Citizens' Statement No. 5R

BEFORE
THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	**Docket No. R-2025-3054394**
	:	
Citizens' Electric Company of Lewisburg, PA	:	

REBUTTAL TESTIMONY

AND EXHIBITS

OF

KATHY STAUDER

ON BEHALF OF

CITIZENS' ELECTRIC COMPANY OF LEWISBURG, PA

AUGUST 13, 2025

BEFORE

THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	**Docket No. R-2025-3054394**
	:	
Citizens' Electric Company of Lewisburg, PA	:	

REBUTTAL TESTIMONY OF KATHY STAUDER
ON BEHALF OF CITIZENS' ELECTRIC COMPANY OF LEWISBURG, PA

Q. Please state your name and business address.

A. My name is Kathy Stauder, and my business address is 1775 Industrial Blvd., Lewisburg, Pennsylvania.

Q. Are you the same Kathy Stauder who previously submitted Direct Testimony in this proceeding on behalf of Citizens' Electric Company of Lewisburg, PA ("Citizens'" or "Company")?

A. Yes. Terms defined in my Direct Testimony have the same meaning in this Rebuttal Testimony.

Q. What is the purpose of your testimony today?

A. The purpose of my testimony is to rebut the testimony of Witnesses Keller, Walters, and Farr, representing the Bureau of Investigation and Enforcement ("I&E"), Office of Consumer Advocate ("OCA"), and Office of Small Business Advocate ("OSBA"), respectively, regarding their proposed adjustments to the Company's Expense Claims. Additionally, I respond to OCA Witness Wise, regarding her recommendations for the Company to implement various changes to its practices related to one-time payment fees and residential customer security deposits.

O&M EXPENSES

Q. Do any of the parties recommend adjustment to the Company's General and Administrative Expense claims?

A. Yes, I&E recommends a decrease of $51,964, OCA recommends a decrease of $62,848, and OSBA recommends a decrease of $8,298.

Q. Please explain the I&E recommendation.

A. I&E's recommended adjustment is based on the individual factors summarized in the table below:

Amount	Reference	Description
$ 8,298	I&E Statement No. 1, p. 9	Generation costs were included by error
$ 380	I&E Statement No. 1, pp. 14-15	"Advertising" is unnecessary and should be disallowed.
$ 330	I&E Statement No. 1, pp. 14-15	Dues are unclear and should be disallowed.
$ 1,030	I&E Statement No. 1, p. 18	Sponsorships should be disallowed.
$ 1,267	I&E Statement No. 1, p. 18	Lobbying should be disallowed.
$ 23,426	I&E Statement No. 1, p 21	Increased meter expense should be disallowed.
$ 17,233	I&E Statement No. 1, p 23	CWC claim recalculated based on above numbers.

Q. Do you agree with these recommendations?

A. Partially, some parts of the recommendation are reasonable, and the Company has included them in Mr. Gorman's Rebuttal Testimony. Others seek to disallow reasonable and well-substantiated expenses that are appropriate to include in our expense claim. I adjust the I&E recommendation in the table below and subsequently address each item in the list following it.

I&E Adjustment	Company Adjustment
$ 8,298	$ 8,298
$ 380	$ 0
$ 330	$ 0
$ 1,030	$ 780
$ 1,267	$ 38
$ 23,426	$ 23,426
$ 17,233	*See Explanation*

- Generation Costs ($8,298)

The Company acknowledges this error in its response to I&E discovery requests and Mr. Gorman will exclude the costs in his revised calculations presented in his Rebuttal Testimony. The same adjustment was proposed by OSBA.

- Advertising ($380)

I&E Witness Walker refers to this expense as "advertising" in his testimony, but in the corresponding exhibit upon which he bases his recommendation[1], the expense is clearly listed as a subscription. In fact, it is the Company's subscription to the local newspaper, which is reviewed daily by the executive team. The local paper includes legal notices that may impact our operations, such as customer bankruptcy and estate notices. Awareness of local, national, and international news is critical to the responsible operation of the Company. In our case, the newspaper is still relied upon as a valuable, and sometimes exclusive, source of information on local events. The $380 expense should be allowed in its entirety.

- Dues ($330)

Upon review of its response referenced in Witness Walker's recommendation[2], the Company finds that the dues in question were mislabeled as "Pennsylvania Department

[1] I&E Exhibit No. 1, Schedule 5, p. 1.
[2] I&E Exhibit No. 1, Schedule 4, p. 2.

of Labor and Industry." They are, in fact, dues for the PA Chamber of Business and Industry. Membership in relevant industry groups provides value to our customers by increasing Company management's awareness of business trends, best practices and proposed legal and regulatory changes affecting our industry, as well as providing training, networking, and benchmarking opportunities. The $330 expense should be allowed in its entirety.

- Sponsorships ($1,030)

The Company acknowledges that a portion of these expenses are used for community engagement rather than direct customer education. I would contest that community engagement does bring value to our ratepayers, and that they expect such interaction from us, but the Company is willing to concede $780 of the expense claim. The remainder of the expense is used for advertising and listings that either inform our customers of relevant utility activities and changes or lists the Company in directories such as the Union County Township Supervisors directory. Witness Farr claims that "this information is easily accessible at all hours of the day on the Company's website, social media, or can be found on customer bills and inserts[3]." A portion of our ratepayers are not on social media and may not have ready access to the website, especially older adults; however, that portion of the ratepayers does rely on print publications. Moreover, Witness Farr is not in a position to dictate what means of communication our ratepayers and other organizations with which we interact prefer.

[3] I&E Statement No. 1, p. 18

- Lobbying ($1,267)

The Company's response to I&E-RE-9-D breaks out the portion of our EAP membership costs that are attributable to lobbying, and the Company agrees that this portion of the expense ($38) should not be included in our expense claim. The remainder is for a valuable industry association membership that the PA Public Utilities Commission ("PUC") and I&E both frequently engage with and seek out to facilitate constructive and beneficial conversations and efforts in conjunction with gas and electric utilities. The adjustment inappropriately excludes the entire EAP dues, rather than just the lobbying portion.

- Meter Expense ($23,426)

Witness Farr asserts that the Company "indicates that the increase between the HTY and FTY in the claim is not due to the purchase of used meters and provided no other reason for the increase in this expense[4]." On August 12, 2025, the Company provided the supplemental response to I&E-RE-11-D, which is attached as Exhibit__(KS-1R). The supplemental response explains that the primary driver for the increase in Account 586 costs from HTY 2024 to FTY 2025 is the decrease in contra labor. Contra labor is meter expense that is capitalized when new meters are installed. In 2024 the Company substantially completed a multi-year programmatic meter replacement initiative. This initiative was executed in lieu of normal cyclical meter and service inspections. With the completion of the capital initiative, maintenance inspections have resumed. The result is that total crew hours identified for meter service work remain the same, but

[4] *Id.* at p. 21.

accounting for that time will shift towards expense rather than capital. We apologize for any confusion created by the delayed service of the revised response.

The $23,426 should be allowed in its entirety.

- CWC Claim ($17,233)

Mr. Gorman will recalculate the CWC Claim in his Rebuttal Testimony based on the final adjusted O&M claim.

Q. Please discuss the OCA's expense adjustments.

A. OCA's recommended adjustment is based on the individual factors summarized in the table below:

Amount	Reference	Description
$ 695	OCA Statement No. 1, pp. 21-22	Sponsorships should be disallowed.
$ 1,267	OCA Statement No. 1, pp. 21-22	Lobbying should be disallowed.
$ 61,739	OCA Statement No. 1, pp. 19-21	Non-labor G&A expenses are not supported.

Q. Do you agree with these recommendations?

A. Partially, some parts of the recommendation are reasonable, and the Company has included them in Mr. Gorman's Rebuttal Testimony. I adjust the OCA recommendation in the table below and subsequently address each item in the list following it.

OCA Adjustment	Company Adjustment
$ 695	$ 405
$ 1,267	$ 38
$ 61,739	$ 0

- Sponsorships ($695)

Please see my response to I&E's recommended adjustment to sponsorships, the Company has adjusted FTFPY projected expenses to $250 for this category.

- Lobbying ($1,267)

Please see my response to I&E's recommended adjustment to lobbying, the Company accepts that $38 should be removed for lobbying expense.

- Non-Labor G&A ($61,379)

The increase in non-labor G&A costs is primarily driven by increases in employee benefits costs that follow staffing levels and G&A labor expenses. This includes the modifications to the salaries and employee complement in the Fully Projected Future Test Year ("FPFTY") that is explained by Mr. Johnson. A small portion of the labor and non-labor G&A costs ($20,508 for non-labor) are for the overlap of my position (Treasurer) because I intend to retire in 2026. Planning for a position overlap is a normal business expense, especially for a small workforce like ours. This overlap occurs for many of our positions due to the need to transition the knowledge necessary for the position. It can occur in any year when a retirement occurs. It should also be noted that a similar overlap is expected in 2027 to accommodate the expected retirement of another employee in the same department, but with a longer planned overlap. This is an ordinary business expense and should be allowed. Also, Witness Meyer's suggestion to use a historical growth factor of 5% ignores the Company's well-supported Wage & Salary plan implementation that will result in an approximately 7.5% increase rather than 5%.

Q. Are there any other O&M adjustments or recommendations by the parties that you would like to address?

A. Yes, OSBA recommends a reduction in projected expenses of $16,501 based on inflationary factor calculations, and OCA recommends a $191,571 reduction in overhead line expense. Mr. Johnson will address the overhead line expense item.

Q. Please explain OSBA's recommended reduction.

A. OSBA Witness Farr also recommends a decrease of $16,501 based on his assessment of the Company's use of a "generic inflationary factor[5]." Witness Farr acknowledges that the Company uses a reasonable approach to applying an inflationary factor to project future expenses but recommends omitting the normalization of past year expenses and applying a 2% rather than 3% inflationary factor. Mr. Farr also suggests that using actual 2024 year-end numbers would be the best method to determine 2025 and 2026 projected costs.

Q. Do you agree with this adjustment?

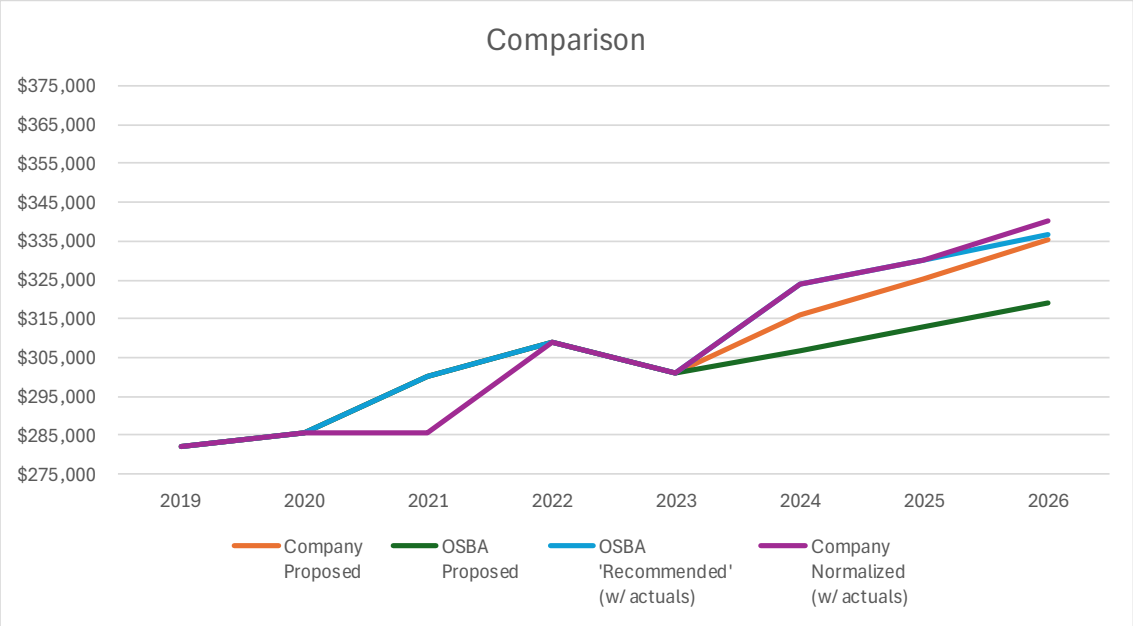
A. No, Witness Farr's omission of a normalization factor of past year expenses undervalues them. He acknowledges inflation but then neglects to normalize past-year actuals for that inflation.

I recalculated FPFTY 2026 expenses with both Witness Farr's "recommended method" of using only actual 2024 expenses[6] and the Company's normalized average method also using actual 2024 expenses. The table and chart below compare both parties' original proposals as well as the two calculations using actual 2024 expenses. OSBA's proposed adjustment to $319,137 is clearly the outlier of the four, while both recalculated expense projections come in slightly higher than the Company's original proposal. I recommend

[5] OSBA Statement No. 1, p. 6
[6] *Id.* at p. 8

that the Company's original proposed expenses for these accounts be accepted as presented in Mr. Gorman's Direct Testimony.

Year	Company Proposed	OSBA Proposed	OSBA 'Recommended' *(w/ actuals)*	Company Normalized *(w/ actuals)*
2019	$ 282,046	$ 282,046	$ 282,046	$ 282,046
2020	$ 285,428	$ 285,428	$ 285,428	$ 285,428
2021	$ 300,083	$ 300,083	$ 300,083	$ 285,428
2022	$ 309,146	$ 309,146	$ 309,146	$ 309,146
2023	$ 300,888	$ 300,888	$ 300,888	$ 300,888
2024	$ 315,946	$ 306,744	$ 323,808	$ 323,808
2025	$ 325,425	$ 312,879	$ 330,284	$ 330,237
2026	$ 335,188	$ 319,137	$ 336,890	$ 340,145



RATE CASE EXPENSE

Q Do any of the parties oppose or recommend adjustments to the Company's proposed rate case expenses?

A Yes, I&E recommends removal of $272,222 in 'amortized' rate case expense, and OSBA recommends a reduction of $5,000 in expected "Printing, other" expenses.

Q Do you agree with these recommendations?

A I will defer to Mr. Gorman's testimony to address the $272,222 expense in his Rebuttal Testimony.

Regarding the $5,000 reduction recommended by OSBA, the Company has already incurred $7,328.92 of actual printing, postage and notices expenses against the expected total of $10,000.

Desc	Expense
Rate Case Notice Printing	$ 3,542.19
Rate Case Notice Postage	$ 2,023.28
Newspaper Notice	$ 745.25
Hearing Notices	$ 1,018.20
Total (to date)	$ 7,328.92

Additional expenses can be expected as the Company proceeds with the filing. Specifically, we expect to incur expenses associated with the public input hearings recently ordered by Commissioner DeFrank. We also will have employee travel, lodging and meal expenses for the hearings, which will be reflected in the "Printing, other" category. A total of $10,000 is not unreasonable given that over $7,000 has been spent already.

ONE-TIME PAYMENT FEES

Q. Please summarize OCA's proposal regarding the $3.95 transaction fee for credit card payments.

A. OCA Witness Wise recommends that the company eliminate fees for credit or debit card payments made through the SmartHub system. Witness Wise further recommends that those fees be included in the Company's O&M expenses and the revenue requirement be adjusted accordingly to recover them.

Q. How do you respond to this recommendation?

A. First, I would clarify that the $3.95 transaction fee is not a fee for using the SmartHub system, it is a fee charged by a third-party payment vendor for all 'one-time' electronic payments, meaning any credit card, debit card, or one-time bank draft, regardless of whether those transactions are made through SmartHub, the pay-by-phone, or any other future system that might be implemented.

In general, I question Witness Wise's assertions that fee-free card payments are "normative[7]," customers are "penalized[8]" by fees, and that elimination of fees is a "growing trend among Pennsylvania Utilities[9]." Witness Wise's suggestion that one-time electronic payment fees are similar to the costs associated with accepting in-person or mailed payments by cash or check ignores the order-of-magnitude disparity in cost of accommodating the different methods. Processing a cash or check payment can be accomplished in just a few seconds of an employee's time, costing $0.25 per transaction[10] or less. Additionally, the Company does not charge any internal labor associated with the management of one-time electronic payment options to customers using those methods, so its treatment of the labor costs associated with customer payments is equitable, regardless of the method used.

Q. Do you believe that fee-free card transactions are normative or a growing trend?

A. No, while it is true that many customers do prefer to use electronic payment methods, and that *many* businesses do not impose extra fees, including *some* Pennsylvania utilities, it is an exaggeration to claim that this is prevailing practice among all businesses or utilities.

[7] OCA Statement No. 4 at p 4, ln 1.
[8] *Id.* at p 4, ln 2.
[9] *Id.* at p 7, ln 12.
[10] Assumes 30s or less per transaction at $30/hr direct wage.

A recent JD Power Study found that 34% of small businesses add a surcharge for card payments.[11] Similarly, the majority of Pennsylvania regulated electric utilities still pass on one-time payment surcharges to individual customers. OCA's suggestion that three water utilities eliminating fees represents a growing trend ignores the remainder of utilities that continue to pass fees through.

Q. Does passing through a one-time payment fee 'penalize' the customer?

A. No, when one-time payment fees are charged to the customer incurring the fee, they are paying exactly for the service they receive. They want the convenience of using the card and they pay the passthrough fee for that convenience. I would also note that some cards offer incentives such as "cash back" rewards or airline miles as an incentive to the card users. Characterizing the current fee as a 'penalty' implies that the fee is over and above actual costs incurred, or that it is intended to disincentivize use of these payment methods, neither of which is true.

Q. What do you feel is the most fair way to recover costs incurred for one-time payment transactions?

A. I believe that the Company's current practice of passing transaction fees through to the Customer's incurring those costs is the most fair and equitable way to recover the costs. The better question may be "what is fair to customers who do not use one-time electronic payments?" To answer this question, I look at three discreet circumstances associated with one-time electronic payments:

1) The company continues as-is, in which case no customer is charged for a service they do not utilize.

[11] https://www.jdpower.com/sites/default/files/file/2025-01/2025002%20U.S.%20Merchant%20Services.pdf

2) The Company eliminates one-time payment fees and absorbs them into distribution rates, in which case customers using one-time payment fees receive this service at a slight discount from actual cost, while customers who do not use it pay increased rates to cover those costs.

3) The Company eliminates one-time payment fees and all customers adopt these methods, in which case all customers would pay the same as they would if they were explicitly charged for the fee, but without any knowledge that their payment methods inflate the cost of service.

Of the three circumstances above, the second—suggested by OCA—is the only one that results in customers paying for a service that they do not benefit from. Ultimately, I believe the Public Utility Commission should address this issue and, should they feel that one-time payment fees are inappropriate, make corresponding changes in regulation to mandate fee-free payment methods.

Q. Do you agree with the OCA's calculation of the revenue requirement impact of eliminating the fee?

A. No. The OCA based its adjustment on historic aggregate fees paid directly by customers; however, we expect that use of the payment method will increase if it becomes free. In conjunction with Valley Energy, Inc., and Wellsboro Electric Company, we analyzed the experiences of a New York utility that eliminated the directly-charged one-time payment fee and assumed the expense into regulated rates. That utility saw a substantial increase in the use of these payment methods once the fee was eliminated. Exhibit__(KS-2) shows the increases that the New York utility experienced and is projecting for the future. If, as OCA suggests, the fee presents a barrier preventing customers from using one-time

payment methods, then it stands to reason that removing the fee would result in increased utilization. Mr. Meyer has not accounted for increased adoption of credit card payments in his calculation of the revenue requirement impact.

Q. What is your recommendation if the Commission were to eliminate the credit card fee?

A. If the Commission eliminates the fee over our objections, then Citizens' should be kept whole if actual annual costs exceed those that have been assumed in the revenue requirement. We should be permitted to book excess fees as a regulatory asset for recovery in our next rate case.

SECURITY DEPOSITS

Q. What changes to the Company's practices regarding security deposits does OCA recommend?

A. OCA Witness Wise recommends that 1) the Company should show that it has formal policies and procedures in place to address how it verifies income levels of new customers before requiring a deposit, and then refunds a deposit if it later finds one should not have been charged, and 2) customers eligible for a refunded deposit should be allowed to decide if the deposit should be credited to their account balance or refunded to them directly in its entirety.

Q. Is the Company providing formal policies and procedures in response to the first recommendation?

A. No, the existence of formal policies and procedures does not change the Company's practices, it only documents them. The Company has already described how it handles deposit collection and income verification of new customers. With only three employees

handling all new customer accounts, formal written policies and procedures are not necessary to train employees or to assure consistent practice throughout the customer service staff.

Q. Do you believe the Company should change its current practices related to refunded deposits?

A. No, the Company's practice on refunding deposits to customers is reasonable. I would note that we refund deposits for a number of reasons, including the customer demonstrating sufficient payment performance or a customer alerting us that they have a change in circumstances that may warrant waiving the security deposit. In all situations, the customer is given the option to credit the entire security deposit balance to their account for their convenience, this is voluntary. If the customer would rather their deposit be returned to them, the Company will return the deposit less any outstanding balance on the account. This practice has no effect on customers who pay their bills on time. For those that are behind on payment, it is only logical to cover outstanding charges with the deposit, rather than return the funds to the customer who immediately owes some or all of that amount back to cover their balance.

Q. Finally, is the Company willing to ensure that low-income households have the opportunity to explore a waiver of a security deposit?

A. Yes. We can do this by asking the customer whether they want to explore whether they qualify for a waiver after we inform them that we need a deposit.

UPDATED FTY PLANT AND EXPENSES

Q. Have you prepared updated actual plant and expense exhibits through the 2nd Quarter 2025?

A. Yes. Those updates are included as Exhibit__(KS-3R) and Exhibit__(KS-4R).

Q. Does this complete your Rebuttal Testimony?

A. Yes.

BEFORE

THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	**:**	
	:	
v.	**:**	**Docket No. R-2025-3054394**
	:	
Citizens' Electric Company of Lewisburg, PA	**:**	

EXHIBITS

OF

KATHY STAUDER

ON BEHALF OF

CITIZENS' ELECTRIC COMPANY OF LEWISBURG, PA

AUGUST 13, 2025

CITIZENS' ELECTRIC COMPANY OF LEWISBURG, PA
DOCKET NO. R-2025-3054394

I&E-RE-11-D

Reference Company Exhibit HSG-1, Schedule C1-1, p. 1 concerning Meter Expense (Account 586), provide the following:

A. A detailed breakdown for the following: 2023 - $25,262; HTY 2024 - $24,042; FTY 2025 - $48,958; FPFTY 2026 - $50,712.
B. A detailed explanation for the 103.6% [{($48,958 - $24,042) ÷ $24,042} x 100] anticipated increase between HTY 2024 and FTY 2025.

Response Provided By:
Nathan Johnson, President & Chief Executive Officer, Citizens' Electric Company

Date: June 3, 2025

Response:

A. See the attachment titled I&E-RE-11-D Attachment A for a detailed breakdown of costs.

B. The Company has been provided with an opportunity to purchase a large quantity of recently installed, used meters from another utility as that utility phases out its TWACS system in the coming years. These purchases, though in excess of current operational needs, will provide a substantial savings over time compared to the cost of purchasing the same quantity of meters new from the manufacturer.

SUPPLEMENTAL RESPONSE TO SUBPART B

B. As shown in the detailed breakdown provided for part (A) of this response, the primary driver for the increase in Account 586 costs from HTY 2024 to FTY 2025 is the decrease in contra labor. Contra labor is meter expense that is capitalized when new meters are installed. In 2024 the Company substantially completed a multi-year programmatic meter replacement initiative. This initiative was executed in lieu of normal cyclical meter and service inspections. With the completion of the capital initiative, maintenance inspections have resumed. The result is that total crew hours identified for meter service work remain the same, but accounting for that time will shift towards expense rather than capital.

Response Provided By:
Nathan Johnson, President & Chief Executive Officer, Citizens' Electric Company

Date: August 12, 2025

Corning Natural Gas

EXHIBIT__(KS-2R)

	actual 2018	actual 2019	actual 2020	actual 2021	actual 2022	actual 2023	actual 2024	2025	2026	2027	2028	2029
				eliminated fee				approved in rate case				
# of transactions	11,590	19,240	25,575	30,063	39,253	45,913						
% increase		66.01%	32.93%	17.55%	30.57%	16.97%						
*fees		$ 46,176	$ 52,242	not available	$ 66,288	$ 78,683	$ 98,344	$ 107,914	$ 114,872	$ 120,839	$ 125,556	$ 129,679
% increase						18.70%	24.99%	9.73%	6.45%	5.19%	3.90%	3.28%

*fees - credit/debit varied by type of payment, not a single fee.

Exhibit-KS-3R

	Historic Year Actual Ended 12/31/21	Historic Year Actual Ended 12/31/22	Historic Year Actual Ended 12/31/23	Historic Year Actual Ended 12/31/24	Future Test Year Ended 12/31/25	Actual Ended 03/31/25	Actual Ended 06/30/25	Fully Projected Future Test Year Ended 12/31/26
Distribution Expenses:								
580 Operations Supt & Eng	131,110	157,885	139,449	147,492	151,142	40,688	84,065	154,958
582 Station Expense	13,239	1,657	20,968	5,258	13,979	1,026	11,079	14,046
583/584 Overhead Line Expense	207,522	132,517	242,610	226,033	234,927	41,557	94,192	242,072
585 Street Lighting Expense	7,724	2,731	8,095	12,169	5,025	3,767	5,610	5,137
586 Meter Expense	19,012	32,554	25,262	24,042	48,958	(5,635)	(4,582)	50,712
587 Customer Installation Expense	60,744	35,338	39,845	41,115	53,765	9,122	27,340	56,416
588 Miscellaneous Distribution Exp	293,481	321,029	395,055	455,104	486,415	130,933	269,651	495,254
589 Rents	499	509	520	530	525	-	-	525
Total Operating Expense	733,331	684,220	871,804	911,743	994,735	221,458	487,355	1,019,120
590 Maint Supv & Eng	-	-	-	-	-	-	-	-
591 Maint of Structures	-	-	-	-	-	-	-	-
592 Maintenance of Station Equipment	5,435	5,256	2,202	25,133	16,832	-	128	17,209
593 Maintenance of Overhead Line	481,913	499,708	563,525	558,565	667,211	161,323	314,492	826,836
594 Mainteneance of Underground Lines	4,246	5,304	16,532	13,331	14,361	1,240	3,123	14,827
595 Maintain Line Transformers	18,983	16,165	85,912	31,968	26,967	626	1,294	27,468
596 Maint. Street Light & Signal Expense	9,879	19,558	22,847	15,914	23,596	4,896	8,492	24,187
597 Maint of Misc. Distrib Plant	367	-	-	-	-	-	-	-
Total Maintenance Expense	520,823	545,991	691,018	644,911	748,968	168,085	327,529	910,527
Total Operating & Maintenance Exp.	1,254,154	1,230,211	1,562,822	1,556,654	1,743,703	389,543	814,884	1,929,647
Customer Accounting & Collection Expenses:								
902 Meter Reading Expense	13,633	24,086	25,085	26,338	26,000	6,717	13,546	26,000
903 Customer records & Collections Exp	442,188	441,004	474,977	483,001	486,259	110,716	232,601	492,479
904 Uncollectible Accounts	31,941	43,106	31,906	27,330	30,000	6,177	14,109	30,900
Total Customer Acctg & Coll. Exp	487,762	508,196	531,968	536,669	542,259	123,610	260,256	549,379
Sales Expense, Public Relations								
908-913 Safety and Communications	-	-	-	-	-	-	-	-
Administrative & General Expenses:								
920 Administrative & General Salaries	607,671	631,219	742,994	700,832	732,830	190,784	389,664	884,948
921 Office Supplies & Expenses	206,061	222,508	243,492	145,653	246,988	67,313	137,770	254,397
923 Outside Services Employed	5,525	24,549	47,103	40,008	37,000	41,225	42,128	38,110
924 Property Insurance	11,112	11,320	11,431	11,190	11,059	2,766	5,622	11,059
925 Injuries & Damages	26,647	26,694	27,561	27,341	28,907	6,768	13,564	28,907
926 Employee Pensions & Benefits	1,756	14,579	6,204	7,497	8,500	1,494	2,223	8,755
928 Regulatory Commission Expense	108,668	108,672	105,515	70,128	88,208	17,532	35,064	117,187
930 Miscellaneous General Expense	94,585	101,474	105,300	110,600	110,891	25,885	54,475	114,218
931 Rents	-	-	-	-	-	-	-	-
932 Maintenance of General Property	163,227	225,917	121,914	155,101	164,713	66,732	113,999	165,455
Total Administrative & General Exp.	1,225,252	1,366,932	1,411,514	1,268,350	1,429,095	420,499	794,509	1,623,036
Total Operating & Maintenance Exp.	2,967,168	3,105,339	3,506,304	3,361,673	3,715,057	933,652	1,869,649	4,102,062
Check to C1-1	*$2,967,168*	*$3,105,339*	*$3,506,304*	*$3,361,673*	*$3,715,057*			*$4,102,061*

		Historic Actual	Historic Actual	Historic Actual	Historic Actual	Future Test Year	Actual	Actual	Fully Projected Future Test Year
		Balance 12/31/21	Balance 12/31/22	Balance 12/31/23	Balance 12/31/24	Forecast 12/31/25	03/31/25	06/30/25	Forecast 12/31/26
Depreciable Plant:									
360	Land & Land Rights	15,708	16,191	17,040	19,360	19,360	18,472	18,535	20,458
361	Structures and Improvements	-	-	-	-	-			-
362	Station Equipment	792,280	792,280	792,280	776,412	776,412	776,412	776,412	776,412
364	Poles, Tower & Fixtures	4,113,235	4,252,749	4,317,240	4,446,001	4,612,432	4,728,592	4,794,379	4,934,235
365	Overhead Conductors & Devices	7,654,591	8,156,039	8,043,524	8,440,384	9,142,814	8,523,796	8,633,838	9,866,317
367	Underground Conduit	3,228,218	3,398,864	3,485,764	3,663,255	3,860,336	3,711,779	3,808,051	4,063,329
368	Line Transformers	2,788,156	2,898,891	2,950,070	3,057,802	3,241,585	3,049,538	3,159,262	3,430,881
369	Services	3,879,146	4,046,185	4,130,180	4,345,865	4,643,243	4,384,015	4,447,588	4,949,542
370	Meters	2,007,239	2,161,712	1,478,201	1,684,809	1,740,941	1,720,416	1,730,536	1,798,757
373	Steet Lighting & Signal Systems	750,787	783,253	680,950	689,618	753,904	701,082	701,423	820,118
Total Distribution Plant		25,229,360	26,506,164	25,895,249	27,123,506	28,791,027	27,614,103	28,070,024	30,660,049
General Plant									
390.1	Structures & Improvements, Office	647,963	668,746	721,358	778,416	813,880	778,958	778,958	874,824
390X	General - Fully Depreciated	764,864	764,864	319,218	319,218	319,218	319,218	319,218	319,218
391	Office Furniture & Equipment	341,801	442,747	595,278	444,831	482,109	444,273	473,686	546,167
392	Transportation Equipment	941,166	1,134,909	1,294,630	1,421,931	1,846,931	1,421,946	1,421,947	2,232,931
394	Tools, Shop & Garage Equipment	69,432	70,820	128,054	137,291	143,816	137,291	137,291	150,340
395	Laboratory & Stores Equipment	70,969	70,969	105,987	105,987	105,987	117,833	117,833	105,987
397	Communication Equipment	272,313	272,313	405,497	428,037	428,037	428,036	428,036	428,037
398	Miscellaneous Equipment	18,110	18,110	43,615	43,615	47,090	31,770	31,770	50,566
	Intangible Plant, Organization	-	-	995	995	995	995	995	995
301	Intangible Plant, EDI	319,218	342,651	-	-	-	-	-	-
Total General Plant		3,445,836	3,786,129	3,614,632	3,680,321	4,188,063	3,680,319	3,709,734	4,709,065
Total Plant In Service		28,675,196	30,292,293	29,509,881	30,803,827	32,979,090	31,294,422	31,779,758	35,369,114
Check to C3		*$28,675,196*	*$30,292,293*	*$29,509,881*	*$30,802,761*	*$32,979,090*			*$35,369,114*

BEFORE
THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No. R-2025-3054394
	:	
Citizens' Electric Company of Lewisburg, PA	:	
	:	

Citizens' Electric Company of Lewisburg, PA Hearing Exhibit 1

Citizens' Electric Company of Lewisburg, PA ("Citizens'") intends to submit the following into the evidentiary record in the above captioned proceeding at the hearing scheduled for September 4, 2025 in Harrisburg, PA.

Joint	Statement No. 2 – Revised Direct Testimony and Exhibit of Dylan W. D'Ascendis, Appendix A, and Exhibit __ (DWD-1)
Joint	Statement No. 2R – Rebuttal Testimony of Dylan W. D'Ascendis and Exhibit __ (DWD-1R)
Joint	Joint Statement No. 2A - Direct Testimony of Ryan M. Kucan and Exhibit__(RMK-1)
Joint	Statement No. 3 – Direct Testimony of Melissa Sullivan and Exhibit __ (MS-1) through Exhibit __ (MS-7)
Joint	Verification of Dylan W. D'Ascendis
Joint	Verification of Ryan M. Kucan
Joint	Verification of Melissa Sullivan

Citizens'	Statement No. 1 – Direct Testimony of Howard S. Gorman, Attachment A, and Exhibit __ (HSG-1)
Citizens'	Statement No. 1R – Rebuttal Testimony of Howard S. Gorman and Exhibit __ (HSG-1R)
Citizens'	Statement No. 1SR – Surrebuttal Testimony of Howard S. Gorman
Citizens'	Statement No. 1RJ – Written Rejoinder of Howard S. Gorman

Citizens' Statement No. 4 – Direct Testimony of Nathan Johnson and Exhibit __ (NJ-1) through Exhibit __ (NJ-8)

Citizens' Statement No. 4R –Rebuttal Testimony of Nathan Johnson and Exhibit __ (NJ-1R) through Exhibit __ (NJ-6R)

Citizens Statement No. 4SR –Surrebuttal Testimony of Nathan Johnson and Exhibit __ (NJ-1SR) through Exhibit __ (NJ-2SR)

Citizens' Statement No. 4RJ – Written Rejoinder of Nathan Johnson and Exhibit__(NJ-1RJ)

Citizens' Statement No. 5 – Direct Testimony of Kathy Stauder and Exhibit __ (KS-1) through Exhibit __ (KS-5)

Citizens' Statement No. 5R – Rebuttal Testimony of Kathy Stauder and Exhibit __ (KS-1R) through Exhibit __ (KS-4R)

Citizens' Verification of Kathy Stauder

I&E Statement No. 1
Witness: Zachari Walker

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

WELLSBORO ELECTRIC COMPANY

Docket No. R-2025-3054392

Direct Testimony

of

Zachari Walker

Bureau of Investigation and Enforcement

Concerning:

OPERATING AND MAINTENANCE EXPENSES

STATE INCOME TAX EXPENSE

RATE BASE

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INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Zachari Walker, and my business address is Pennsylvania Public Utility Commission, Commonwealth Keystone Building, 400 North Street, Harrisburg, PA 17120.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by the Pennsylvania Public Utility Commission (Commission or PUC) in the Bureau of Investigation & Enforcement (I&E) as a Fixed Utility Financial Analyst.

Q. WHAT IS YOUR EDUCATION AND EMPLOYMENT BACKGROUND?

A. My education and employment background is attached as Appendix A.

Q. PLEASE DESCRIBE THE ROLE OF I&E IN RATE PROCEEDINGS.

A. I&E is responsible for representing the public interest in rate and other proceedings before the Commission. I&E's analysis in these proceedings is based on its responsibility to represent the public interest. This responsibility requires the balancing of the interests of the ratepayers, the regulated utility, and the regulated community as a whole.

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. The purpose of my direct testimony is to review the base rate filing of Wellsboro Electric Company (Wellsboro or Company), and recommend adjustments to the Company's proposed operating and maintenance (O&M) expenses, state income tax expense, and rate base for the fully projected future test year (FPFTY) ending December 31, 2026.

Q. DOES YOUR DIRECT TESTIMONY INCLUDE AN EXHIBIT?

A. Yes. I&E Exhibit No. 1 contains schedules that support my direct testimony.

Q. WHAT ARE THE TEST YEARS USED BY THE COMPANY IN THIS PROCEEDING?

A. Wellsboro uses the twelve months ended December 31, 2024, as the historic test year (HTY), the twelve months ending December 31, 2025, as the future test year (FTY), and the twelve months ending December 31, 2026, as the FPFTY.

Q. WHAT IS THE EFFECTIVE DATE PROPOSED FOR NEW RATES?

A. The Company indicates that its effective date for new rates is January 30, 2026, however, the rate change could be effective earlier if the parties agree to a settlement that includes an accelerated effective date and that settlement is approved by the Commission.[1]

[1] Wellsboro Statement No. 1, p. 2.

Q. DO YOU AGREE WITH THE POSSIBILITY THAT NEW RATES MAY GO INTO EFFECT PRIOR TO THE JANUARY 30, 2026 EFFECTIVE DATE?

A. Not entirely. Under any circumstances, rates should not go into effect prior to the beginning of the FPFTY which is January 1, 2026. This date is the beginning of the twelve-month period on which new rates are based. For this reason, it would be unjust and unreasonable for ratepayers to pay the increase in rates prior to the beginning of the first day of the FPFTY.

Q. PLEASE SUMMARIZE THE COMPANY'S REQUESTED REVENUE INCREASE.

A. The Company's base rate case was filed on April 30, 2025, with a total requested increase of $2,899,388 to the claimed present rate revenues of $6,729,636 resulting in an overall revenue requirement of $9,629,025.[2]

Q. PLEASE SUMMARIZE YOUR RECOMMENDED ADJUSTMENTS.

A. The following table summarizes my recommended adjustments:

[2] Wellsboro Exhibit HSG-1, Schedule C1.

	Wellsboro FPFTY Claim	I&E Recommended Allowance	I&E Adjustment
O&M Expenses:			
Rate Case Expense	$110,393	$66,236	($44,157)
Membership Dues and Subscriptions	$12,804	$0	($12,804)
Miscellaneous Distribution Expense	$285,688	$0	($285,688)
Total O&M Adjustments			**($342,649)**
Taxes:			
State Income Tax Expense	$186,526	$100,549	($85,978)
Total Tax Adjustments			**($85,978)**
Rate Base Adjustments:			
Unamortized Rate Case Expense	$275,981	$0	($275,981)
Cash Working Capital	($517,744)	($474,913)	($42,831)
Total Rate Base Adjustments			**($318,812)**

SUMMARY OF I&E OVERALL POSITION

Q. WHAT IS I&E'S TOTAL RECOMMENDED REVENUE REQUIREMENT?

A. I&E's total recommended revenue requirement for Wellsboro is $9,008,787. This recommended revenue requirement represents an increase of $2,279,151 to the claim for present rate revenues of $6,729,636. This total recommended allowance incorporates my adjustments made in this testimony to O&M expenses and rate base, and those made in the testimonies of I&E witnesses Christopher Keller[3] and Ethan Cline.[4]

[3] I&E Statement No. 2.
[4] I&E Statement No. 3.

A calculation of the I&E recommended revenue requirement is shown in the table below:

Wellsboro Electric Company		TABLE I			
R-2025-3054392		INCOME SUMMARY			
	12/31/26	INVESTIGATION & ENFORCEMENT			
	Proforma	[			]
	Present Rates	Adjustments	Present Rates	Allowances	Proposed
	$	$	$	$	$
Operating Revenue	6,729,636	0	6,729,636	2,279,151	9,008,787
Deductions:					
O&M Expenses	4,333,019	-342,649	3,990,370	0	3,990,370
Depreciation	1,939,404	0	1,939,404		1,939,404
Taxes, Other	421,866	0	421,866	134,470	556,336
Income Taxes:					
Current State	-86,033	25,945	-60,088	160,637	100,549
Current Federal	-162,784	67,296	-95,488	416,649	321,161
Deferred Taxes	109,094	0	109,094		109,094
ITC	0	0	0		0
Total Deductions	6,554,566	-249,408	6,305,158	711,756	7,016,914
Income Available	175,070	249,408	424,478	1,567,395	1,991,873
Measure of Value	25,857,280	-188,819	25,668,461	0	25,668,461
Rate of Return	0.68%		1.65%		7.76%

RATE CASE EXPENSE

Q. BRIEFLY DESCRIBE THE NATURE AND TYPES OF EXPENDITURES TYPICALLY ALLOWED AS PART OF A REGULATED UTILITY'S OVERALL RATE CASE EXPENSE.

A. The nature and types of individual expenditures that comprise a regulated utility's allowable claim for rate case expense are those directly incurred to compile, present, and defend a utility's request for a base rate increase before the Commission. The actual expenditures and estimated costs typically found in an

allowable rate case expense claim include legal fees for outside counsel, fees to outside consultants, and the cost of printing, document assembly, and postage.

Q. HOW HAS THE COMMISSION TRADITIONALLY TREATED RATE CASE EXPENSE FOR RATEMAKING PURPOSES?

A. The Commission has historically stated that it considers prudently incurred rate case expense as an ongoing expense, occurring at irregular intervals, related to the rendering of utility service. The Commission has also cited the importance of considering the involved utility's history regarding the frequency of rate case filings as an essential element in determining the normalized level of rate case expense for ratemaking purposes.[5]

Q. HOW IS THE FREQUENCY OF RATE CASE FILINGS DETERMINED?

A. The frequency is determined by calculating the average number of months between the filing dates of a utility's recently filed base rate cases.

Q. WHAT IS THE COMPANY'S CLAIM FOR RATE CASE EXPENSE?

A. Wellsboro is claiming a rounded FPFTY rate case expense claim of $110,393.[6]

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[5] "A Guide to Utility Ratemaking," by James H. Cawley and Norman J. Kennard (2018 Edition), p. 112, https://www.puc.pa.gov/General/publications_reports/pdf/Ratemaking_Guide2018.pdf, accessed July 2, 2025.

[6] Wellsboro Exhibit HSG-1, Schedule C1-3.

Q. WHAT IS THE BASIS FOR THE COMPANY'S CLAIM?

A. The Company's claim is based on estimated total rate case expenses of $331,178[7] expensed over three years – its anticipated interval between the instant proceeding and the Company's next base rate case filing. Wellsboro contends that despite its previous rate case having been filed in 2019, the Company expects it will file a rate case every three years going forward.[8] The result is the Company's proposed FPFTY claimed rate case expense of $110,393.[9]

Q. WELLSBORO INTERCHANGEABLY REFERENCES ITS RATE CASE EXPENSE CLAIM AS AN AMORTIZED COST AND A NORMALIZED COST.[10] BRIEFLY DISCUSS THE CONCEPT OF AMORTIZATION.

A. Amortization is an accounting procedure that writes off a non-recurring or infrequently recurring asset over a predetermined number of years by incrementally charging to expense the total cost over the selected amortization period. Amortization for ratemaking purposes is generally limited to expense events that have been authorized for deferral by the Commission through specific company petitions for which a regulatory asset is established. Although a claim for an unrecovered normalized expense would be disallowed if requested in a subsequent base rate case, an amortized expense allowance could be claimed in a

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7 *Id.*
8 I&E Exhibit No. 1, Schedule 1, p. 2.
9 Wellsboro Exhibit HSG-1, Schedule C1-3.
10 Wellsboro Statement No. 1, pp. 10-11; Wellsboro Exhibit HSG-1, Schedules C1 and C1-3.

succeeding rate case if there is a remaining unamortized balance.

Q. DO YOU AGREE WITH THE COMPANY'S PROPOSED AMORTIZATION TREATMENT FOR RATE CASE EXPENSE?

A. No. The Company's rate case expense claim should be normalized for ratemaking purposes.

Q. WHAT IS NORMALIZATION?

A. Normalization is a ratemaking concept that describes the transformation of an operating expense that recurs at irregular intervals into a "normal" annual test year allowance. Normalization specifically addresses the prospective recovery of an ongoing expense that recurs sporadically. Normalized expenses are no different than other O&M expenses in that the utility is given the opportunity to achieve full recovery.

Q. DO YOU AGREE WITH THE COMPANY'S CLAIM?

A. No.

Q. WHAT IS YOUR RECOMMENDATION FOR RATE CASE EXPENSE?

A. I recommend an allowance of $66,236 for rate case expense, or a reduction of $44,157 ($110,393 - $66,236) to the Company's claim.

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATION?

A. First, I recommend that Wellsboro be required to normalize its rate case expense as opposed to amortizing it, since the Commission recognizes rate case expense as an ongoing expense occurring at irregular intervals, related to the rendering of utility service. As such, rate case expense is subject to normalization for ratemaking purposes and expensing amounts for prior proceedings should not be allowed.

Next, the Company's historic filing frequency does not support a three-year recovery period for rate case expense. The Company's three most recent base rate case filing dates and corresponding details for the current filing are as follows:

Docket No.	Date Filed[11]	Filing Interval
R-2025-3054392	April 30, 2025	70 months
R-2019-3008208	July 3, 2019	40 months
R-2016-2531551	March 1, 2016	69 months
R-2010-2172662	June 3, 2010	

Including the current rate case, filed on April 30, 2025, the average historic filing frequency is approximately 60 months [(70 months +40 months + 69 months) ÷ 3]. Therefore, I recommend the 60-month average historic filing frequency be used as the normalization period, consistent with the Commission's emphasis on the importance of considering the utility's history of rate case filings when determining the normalization period of rate case expenses. Normalizing

[11] I&E Exhibit No. 1, Schedule 1, p. 1.

the total claims over the average historic filing frequency of 60 months yields my recommended FPFTY allowance of $66,236 [($331,178 ÷ 60 months) x 12 months] for rate case expense. My recommended FPFTY allowance represents a reduction of $44,157 ($110,393 - $66,236) to the Company's FPFTY claimed rate case expense.

Q. HAVE OTHER UTILITIES BEEN GRANTED A NORMALIZATION PERIOD BASED ON SPECULATION OF FUTURE RATE CASE FILINGS?

A. Yes. In 2012, the Commission granted PPL Electric Utilities Corporation (PPL) permission to normalize its rate case expense over a 24-month period based on the expected timing of future base rate case filings.[12] That base rate case was filed on March 30, 2012; however, PPL did not file its next rate case until March 31, 2015, which was 36 months after the 2012 rate case filing. I&E's recommended normalization period in the 2012 PPL proceeding was a 32-month interval based on PPL's historic filing frequency.[13] I&E's recommendation in that instance produced a much more accurate result than PPL's stated future intention to file a rate case.

[12] *Pa. PUC v. PPL Electric Utilities Corporation*, Docket No. R-2012-2290597, pp. 47-48 (Order Entered December 28, 2012).

[13] I&E Statement No. 2, pp. 13-14 at Docket No. R-2012-2290597.

Q. ARE THERE ANY RECENT COMMISSION DECISIONS THAT SUPPORT YOUR RECOMMENDATION FOR A RATE CASE FILING INTERVAL BASED ON HISTORIC FILING FREQUENCY?

A. Yes. The following six cases resulted in the Commission using each utility's historic average filing frequency.

First, in a base rate case filed by Emporium Water Company, the Commission adopted I&E's recommended historic filing frequency finding in favor of I&E's recommended five-year normalization based on historic average filing frequency that was rounded down from 64 months.[14]

Second, in a 2016 base rate case filed by the City of DuBois the Commission agreed with I&E's recommendation to use an historic filing frequency finding in favor of I&E's recommended 64-month normalization which matched the actual historic filing frequency.[15]

Third, in Columbia Gas of Pennsylvania, Inc.'s (Columbia) 2020 base rate case filing, the Commission held that the normalization period should align with the frequency of historic filings rather than Columbia's stated intent to file its subsequent rate case.[16]

Fourth, in PECO Energy Company – Gas Division's (PECO Gas) 2020 base rate filing, the Commission granted I&E's recommended five-year

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[14] *Pa. PUC v. Emporium Water Company*, Docket No. R-2014-2402324, p. 50 (Order Entered January 28, 2015).

[15] *Pa. PUC v. City of DuBois - Bureau of Water*, Docket No. R-2016-2554150, pp. 65-66 (Order Entered March 28, 2017); *PA PUC v. City of DuBois - Bureau of Water*, Docket No. R-2016-2554150, p. 13 (Order Entered May 18, 2017).

[16] *Pa. PUC v. Columbia Gas,* Docket No. R-2020-3018835, Opinion and Order, pp. 78-79 (Order Entered February 19, 2021).

normalization period rather than PECO Gas' claim based on a three-year period because the Commission determined a normalization period based on actual historic filing frequency is more reliable than future speculation.[17]

Fifth, in a base rate case filed by Philadelphia Gas Works' (PGW) in 2023, the Commission agreed with I&E's recommended 53-month normalization period rather than PGW's claim based on a three-year period because the Commission granted a normalization period based on actual historic filing frequency and not based on PGW's future intention to file a rate case.[18]

Finally, in the most recent base rate case filed by the Columbia Water Company in 2023, the Commission held that the normalization period should align with the historic filing frequency rather than that company's intent to file its next rate case, and that the intent to file a base rate case does not justify deviating from the Commission's practice of relying on historic filing frequency.[19]

Q. GIVEN THESE COMMISSION ORDERS AND THE COMPANY'S FILING HISTORY, IS THE CLAIMED 36-MONTH RECOVERY PERIOD REASONABLE?

A. No. As explained above, the Company's demonstrated historic filing frequency is 60 months, therefore, normalizing the total claims over this average historic filing

[17] *Pa. PUC v. PECO Energy Company (Gas Division)*, Docket No. R-2020-3018929, Opinion and Order, p. 119 (Order Entered June 22, 2021).

[18] *Pa. PUC v. Philadelphia Gas Works*, Docket No. R-2023-3037933, Opinion and Order, pp. 65-66 (Order Entered November 9, 2023).

[19] *Pa. PUC v. Columbia Water Company*, Docket No. R-2023-3040258, Opinion and Order, p. 34 (Order Entered January 18, 2024).

frequency is more appropriate.

Q. DO YOU HAVE ANY OTHER ISSUE TO ADDRESS RELATED TO RATE CASE EXPENSE?

A. Yes. The Company improperly claims the unamortized portion of rate case expense as a regulatory asset in rate base. This issue is addressed in the following section.

UNAMORTIZED RATE CASE EXPENSE IN RATE BASE

Q. WHAT IS INCLUDED IN THE COMPANY'S RATE BASE CLAIM FOR RATE CASE EXPENSE?

A. The Company is claiming a regulatory asset in rate base that represents unamortized rate case expense.[20]

Q. WHAT IS THE COMPANY'S CLAIM FOR UNAMORTIZED RATE CASE EXPENSE IN RATE BASE?

A. The Company is claiming $275,981 in a regulatory asset.[21]

Q. WHAT IS THE BASIS FOR THE COMPANY'S CLAIM?

A. The Company opines that it must recover both the cost of the asset as well as the

[20] I&E Exhibit No. 1, Schedule 2, pp. 1-2.
[21] Wellsboro Exhibit HSG-1, Schedule C1-5, p. 2.

carrying cost of the unrecovered funds expended to obtain the asset.[22]

Q. DO YOU AGREE WITH THE COMPANY'S CLAIM?

A. No.

Q. WHAT DO YOU RECOMMEND?

A. I recommend the entire claim of $275,981 be disallowed.

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATION?

A. It is well established that rate case expense, which is a routine operating expense for a regulated utility and not an asset, should be normalized and not amortized for ratemaking purposes. Thus, regulatory asset treatment for an unamortized rate case expense balance is inappropriate.

Q. WHY WOULD IT BE INAPPROPRIATE TO INCLUDE UNAMORTIZED RATE CASE EXPENSE IN RATE BASE?

A. If the Company were allowed to include unamortized rate case expense in rate base along with capturing an amount on the expense side, it would earn a return on and a return of rate case expense, a routine operating expense. Any allowance for return on an expense, in addition to a return of such an expense, is not an appropriate ratemaking practice. Also, as stated previously, with respect to rate

[22] I&E Exhibit No. 1, Schedule 2, p. 2.

case expense, normalization of such a claim, rather than amortization, is the appropriate ratemaking treatment, and normalization does not include a remaining balance nor allow for a remaining balance to be captured in rate base. Rate case expense represents a routine operating expense which is not extraordinary in nature. As such, rate base treatment of this cost should not be granted.

MEMBERSHIP DUES AND SUBSCRIPTIONS

Q. WHAT IS THE COMPANY'S CLAIM FOR MEMBERSHIP DUES AND SUBSCRIPTIONS?

A. In response to I&E-RE-10-D, Wellsboro identified $12,804 ($6,000 + $3,400 + $32 + $3,372) in membership dues and subscriptions for the FPFTY.[23] Wellsboro's FPFTY claim consists of bank fees of $6,000, subscriptions of $3,400, lobbying expenses and political campaign donations of $32, and membership dues & subscriptions of $3,372.[24]

Q. WHAT IS THE BASIS FOR THE COMPANY'S CLAIM?

A. The Company states the bank fees are incurred when managing customer payments and processing transactions.[25] The subscriptions claim is based on costs to support administrative tasks and access up to date industry information.[26] The

[23] I&E Exhibit No. 1, Schedule 3, p. 1.
[24] *Id.*
[25] *Id*. at p. 2.
[26] *Id.*

lobbying expenses represent indirect lobbying efforts by the Company.[27] Finally, the membership dues are paid to industry associations to access regulatory updates, best practices, and training opportunities.[28]

Q. DO YOU AGREE WITH THE COMPANY'S CLAIM FOR MEMBERSHIP DUES AND SUBSCRIPTIONS?

A. No.

Q. WHAT IS YOUR RECOMMENDATION FOR MEMBERSHIP DUES AND SUBSCRIPTIONS CLAIM?

A. I recommend disallowing the entire $12,804 membership dues and subscriptions claims for ratemaking purposes.

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATION?

A. In response to I&E-RE-10-D, when asked to provide details by year, identifying the account name and number, the payee(s), and the expense amount claimed in the HTY, FTY, and FPFTY, and to include the basis for each of the listed expense categories, the Company did not identify the account number nor the payee for any of the expenses.[29] My recommendation to disallow the entire claim for ratemaking purposes is therefore based on the lack of support for the identified expenses.

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[27] *Id.*
[28] *Id.*
[29] I&E Exhibit No. 1, Schedule 3, pp. 1-2.

MISCELLANEOUS DISTRIBUTION EXPENSE

Q. WHAT IS THE COMPANY'S CLAIM FOR MISCELLANEOUS DISTRIBUTION EXPENSE?

A. Wellsboro's FPFTY claim for miscellaneous distribution expense is $285,688.[30]

Q. WHAT IS THE BASIS FOR THE COMPANY'S CLAIM?

A. The Company's miscellaneous distribution expense FPFTY claim consists of labor costs of $140,466, overhead costs of $123,422, and other costs of $21,800;[31] and is based on increased labor and overhead costs due to the FTY redistribution of responsibilities and duties of a previously vacant position.[32]

Q. DO YOU AGREE WITH THE COMPANY'S CLAIM FOR MISCELLANEOUS DISTRIBUTION EXPENSE?

A. No.

Q. WHAT IS YOUR RECOMMENDATION FOR MISCELLANEOUS DISTRIBUTION EXPENSE?

A. I recommend the entire $285,688 FPFTY claim be disallowed for ratemaking purposes.

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30 Wellsboro Exhibit HSG-1, Schedule C1-1, p. 1.
31 Wellsboro Exhibit HSG-1, Schedule WP_C2, pp. 1 & 3.
32 I&E Exhibit No. 1, Schedule 4, p. 1.

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATION?

A. In response to request for a detailed breakdown of the annual costs at I&E-RE-12-D,[33] and for further breakdown of the labor and overhead costs at I&E-RE-13-D, [34] the Company did not provide a breakdown sufficient enough to be able to determine whether the items included its miscellaneous distribution expense claim are appropriate for ratemaking purposes.

In response to I&E-RE-12-D, Wellsboro states that the increase in labor costs from the HTY to the FTY are related to a redistribution of responsibilities for a previously vacant position resulting in increased labor and overhead costs.[35] However, the basis for the redistribution methodology lacks sufficient detail to determine whether this is appropriate to include for ratemaking purposes or if this is accounted for in other expense accounts.

Additionally, while Wellsboro's filing does provide an additional breakdown of the miscellaneous distribution expense account; [36] it is not apparent if the costs included in each subaccount are appropriate for ratemaking purposes.

Without being provided greater specificity, it is not evident whether any part of the miscellaneous distribution expense is necessary for the safe and reliable supply of electric service and subsequently appropriate for ratemaking purposes.

[33] I&E Exhibit No. 1, Schedule 4, p. 1.
[34] I&E Exhibit No. 1, Schedule 5, p. 1.
[35] I&E Exhibit No. 1, Schedule 4, p. 1.
[36] Wellsboro Exhibit HSG-1, Schedule WP_C1, p. 13.

Therefore, I recommend the entire $285,688 FPFTY claim be disallowed for ratemaking purposes.

CASH WORKING CAPITAL

Q. WHAT IS A CASH WORKING CAPITAL (CWC) ALLOWANCE FOR RATEMAKING PURPOSES?

A. CWC is defined as the amount of funds necessary to operate a utility during the interim between the rendition of service, including the payment of related expenses and the receipt of revenues in payment of services rendered.

Q. WHAT IS THE COMPANY'S CWC CLAIM?

A. The Company's claim for CWC is $517,744.[37]

Q. HOW DID THE COMPANY CALCULATE ITS CWC CLAIM?

A. The Company used the 1/8 Method, which is also known as the 45-Day Method. The Company's claim was determined by adding all its cash-based operating expenses to arrive at a total of $4,141,955.[38] The resulting figure was multiplied by 1/8 to arrive at a CWC amount of $517,744 [$4,141,955 x (1/8)].[39]

[37] Wellsboro Exhibit HSG-1, Schedule C1-5.
[38] *Id*.
[39] *Id*.

Q. DO YOU AGREE WITH THE COMPANY'S CLAIM?

A. No. I disagree with the Company's CWC claim in as much as I disagree with its cash-based operating expense claims as described above.

Q. WHAT IS YOUR RECOMMENDED ALLOWANCE FOR CWC?

A. I recommend an allowance of $474,913 or a reduction of $42,831 ($517,744 - $474,913) to the Company's claim.

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATION?

A. My recommendation is based on the reflection of all my O&M adjustments to the O&M expenses as discussed above. My recommendation is calculated as follows:

Company's CWC Claim		$517,744
I&E Recommended O&M Expense Adjustments	($342,649)	
1/8 of Total O&M Adjustments		($42,831)
I&E Recommended CWC Allowance		$474,913

Q. IS YOUR RECOMMENDED CWC ALLOWANCE A FINAL RECOMMENDATION?

A. No. All adjustments to the Company's claims for revenues, expenses, taxes, and rate base must be consistently brought together in the Administrative Law Judge's Recommended Decision and again in the Commission's Final Order. This process, which is known as iteration, effectively prevents the determination of a

precise calculation until such time as all adjustments have been made to the Company's claim.

STATE INCOME TAX EXPENSE

Q. WHAT IS THE COMPANY'S CLAIM FOR STATE INCOME TAX EXPENSE?

A. The Company's claim for state income tax expense is $186,526.[40]

Q. WHAT IS THE BASIS FOR THE COMPANY'S CLAIM?

A. The Company's state income tax expense claim is based on the 2022 tax year Pennsylvania corporate net income tax rate of 9.99%.[41]

Q. DO YOU AGREE WITH THE COMPANY'S CLAIM?

A. No.

Q. WHAT DO YOU RECOMMEND FOR STATE INCOME TAX EXPENSE?

A. I recommend an allowance of $100,549 or a reduction of $85,978 ($186,526 - $100,549) to the Company's claim for state income taxes.

[40] Wellsboro Exhibit HSG-1, Schedule C1-4, Line 16.
[41] *Id*.

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATION?

A. On July 8, 2022, Pennsylvania House Bill 1342 was signed into law as Act 53 of 2022. Act 53 lowered the 2022 tax year 9.99% corporate net income tax rate to 7.49% for tax year 2026 (the Company's claimed FPFTY) and will decrease the tax rate by 0.5% each year until 2031, when the tax rate will be 4.99%.[42] Therefore, I recommend a Pennsylvania income tax rate of 7.49% to reflect the Pennsylvania corporate income tax rate that will be in effect for the FPFTY. This change is reflected in my recommended revenue requirement in Table I above[43] and incorporates the state income tax effect of my other recommended adjustments and those of I&E witness Christopher Keller[44] and Ethan Cline.[45]

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

[42] I&E Exhibit No. 1, Schedule 6, p. 1.
[43] I&E Statement No. 1, p. 5.
[44] I&E Statement No. 2.
[45] I&E Statement No. 3.

Zachari Walker

Professional and Educational Background

Experience:

Pennsylvania Public Utility Commission, Harrisburg, Pennsylvania
March 2021 to Present:
Fixed Utility Financial Analyst, Bureau of Investigation and Enforcement

Bridgestone Retail Operations LLC, Nashville, Tennessee
December 2014 to July 2020:
Business Manager
Conducted in-depth operations analysis to determine key performance indicators, corresponding trends, and opportunities for business growth. Promoted business efforts through public teambuilding events, customer recognition and celebrations, and offsite visits with community leaders and vendor partners. Designed development goals and implementation plans with up to 11 team members including plan reassessment dates and goal tracking.

Education/Professional Development:

Bridging the Gap, Holly Ridge, North Carolina, 2021
Business Analyst Blueprint Training Program, 36 PD hours

Stevenson University, Stevenson, Maryland, 2014
Bachelor of Science, *magna cum laude*, Business Administration
Concentration in Finance

Professional Affiliations:

International Institute of Business Analysis (IIBA), Pickering, Ontario, Canada

Utility-Related Trainings & Other Courses/Webinars:

Pennsylvania Public Utility Commission Rate School 2022, January 18-February 8, 2022

Michigan State University Institute of Public Utilities Accounting and Ratemaking Course 2021, September 14-16, 2021

NARUC Staff Subcommittee on Accounting & Finance, Spring 2021 Virtual Conference, April 6-8, 2021

Testimony Submitted:

R-2024-3052357	Pike County Light & Power Company - Gas
R-2024-3047824	Aqua Pennsylvania Wastewater, Inc.
R-2024-3047822	Aqua Pennsylvania, Inc.
R-2024-3046523	Duquesne Light Company
R-2024-3045966	Philadelphia Gas Works – 1307(f)
R-2023-3042805	Community Utilities of Pennsylvania, Inc. – Wastewater Division
R-2023-3042804	Community Utilities of Pennsylvania, Inc. – Water Division
R-2023-3037933	Philadelphia Gas Works
R-2023-3035730	National Fuel Gas Distribution Corporation
R-2022-3032369	Citizens' Electric - Lewisburg
R-2022-3032806	The York Water Company – Wastewater Division
R-2022-3031340	The York Water Company – Water Division
R-2021-3030218	UGI Utilities, Inc. – Gas Division
R-2021-3026682	City of Lancaster – Bureau of Water
R-2021-3026116	Borough of Hanover – Hanover Municipal Water Works
R-2021-3025207	Community Utilities of Pennsylvania Inc. – Wastewater Division
R-2021-3025206	Community Utilities of Pennsylvania Inc. – Water Division

Casework Not Requiring Testimony:

R-2023-3041575	Conneaut Lake Park Water Corporation, Inc.
R-2023-3040285	PECO Energy Co. – Gas Operations 1037(f)
R-2022-3032250	PECO Energy Co. – Gas Operations 1307(f)

I&E Exhibit No. 1
Witness: Zachari Walker

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

WELLSBORO ELECTRIC COMPANY

Docket No. R-2025-3054392

Exhibit to Accompany

the

Direct Testimony

of

Zachari Walker

Bureau of Investigation and Enforcement

Concerning:

OPERATING AND MAINTENANCE EXPENSES

STATE INCOME TAX EXPENSE

RATE BASE

WELLSBORO ELECTRIC COMPANY
DOCKET NO. R-2025-3054392

I&E-RE-8-D

Reference Wellsboro Statement No. 1, pp. 10-11 and Exhibit HSG-1, Schedule C1-1, p. 2, concerning regulatory commission expenses. Provide the following:

A. The docket number, date of filing, and method of resolution (i.e., settlement or litigation) for each of the last three base rate cases filed with the Pennsylvania Public Utility Commission (PUC or Commission).
B. Requested regulatory commission expense and actual regulatory commission expense incurred for each of the base rate cases listed in response to Part A above.
C. Copies of all current outside service contract agreements for rate case-related services.
D. Invoices/receipts for the regulatory commission expenses incurred to date for the current filing and continue to provide updated invoices as regulatory commission expenses are incurred.
E. Identify any claimed expenses attributable to prior rate case proceedings included in Wellsboro current FPFTY 2026 regulatory commission expense claim.
F. A detailed explanation for the basis for why the Company is using a 3-year normalization period to recover regulatory commission expenses.
G. Identify any claimed rate case-related expenses allocated to Wellsboro from any affiliated entity providing a detailed breakdown and explanation of the allocation method along with any formulas used to determine the allocation.
H. A detailed breakdown for the following: 2023 - $68,366; HTY 2024 - $42,985; FTY 2025 - $43,000; FPFTY 2026 - $153,393.

Response Provided By:
Howard Gorman, President, HSG Group, Inc.
Jill Campbell, VP of Finance and Administration, Wellsboro Electric Company

Date: June 3, 2025

Response:

A.

Docket #	Date Filed	Method of Resolution
R-2010-2172662	6/3/2010	Settlement
R-2016-2531551	3/1/2016	Settlement
R-2019-3008208	7/3/2019	Litigation

B.

WELLSBORO ELECTRIC COMPANY
DOCKET NO. R-2025-3054392

Docket #	Requested Expense	Actual (Amortized) Expense	Additional Expense Not Amortizated	Amortization Period (yrs)
R-2010-2172662	200,000	148,404	-	3
R-2016-2531551	230,000	195,650	-	3
R-2019-3008208	326,000	326,000	43,431	3

C. See I&E-RE-8-D **CONFIDENTIAL** Attachment A (HSG), IE-R&E-8-D-**CONFIDENTIAL** Attachment B (McNees), and I&E-RE-8-D **CONFIDENTIAL** Attachment C (ScottMadden).

D.

Date	Invoice	Reference	Vendor Name	Amount
1/31/2025	MISC 01.2025	MCNEES-2025 RATE CASE RESEARCH	C & T ENTERPRISES INC	3,333.34
3/1/2025	HSG2503-02	MILESTONE WEL-25 FILING	HSG GROUP INC	19,000.00
3/31/2025	MISC 03.25	FORVIS-RATE CASE COUNSELING	C & T ENTERPRISES INC	1,460.00
4/29/2025	997981	RATE CASE POSTAGE	VALLEY ENERGY	1,804.23
4/30/2025	5417203	2025 DISTRIBUTION RATE CASE	MCNEES, WALLACE & NURICK LLC	213.00
4/30/2025	MISC 04.25	FORVIS - RATE CASE CONSULTING	C & T ENTERPRISES INC	1,000.00
5/1/2025	HSG2504-02	MILESTONE WEL25-3 FILING	HSG GROUP INC	28,000.00
5/1/2025	2205528	RATE CASE NOTICES	CLARE PRINTING	3,262.54
				58,073.11

E. There are none.

F. The Company expects to file a rate case every three years, due to the continuing need for capital investment to meet demand, and due to normal cost inflation. Althought the Company has not filed a rate case since 2019, this period is considered unusual due to several new larger loads that were added. The Company's sister companies, as well as many other utilities, file rate cases every three years.

G. There are none.

H.

	2023	2024	2025	2026
General Assessment	32,144	42,985	43,000	43,000
Rate Case Expense	36,222	-	-	110,393
Total	68,366	42,985	43,000	153,393

The expense shown in FTY 2025 includes an estimate for the General Assessment, which is not expected to be received until August or September 2025. The FPFTY reflects the same estimated amount for the General Assessment, along with the initiation of amortization for projected rate case expenses.

I&E-RE-22

Reference Wellsboro Exhibit HSG-1, Schedule C1-5 concerning the regulatory asset claim. Provide the following:

A. Explanation and detailed calculations/breakdown for what the $331,178 FTY claim represents.

B. Explanation and detailed calculations/breakdown for what the $275,981 FPFTY claim represents.

C. State whether the regulatory asset claim of $275,981 represents unamortized rate case expense, and if not, explain in detail what it represents.

D. State why the difference between the FTY and FPFTY claims, $55,197 ($331,178 - $275,981), is approximately half of the claimed annual rate case expense, $110,394 ($55,197 x 2), shown on Schedule C1-3, line 21, $110,393.

E. The basis for why it is appropriate to include the regulatory asset in rate base for ratemaking purposes.

Response Provided By:
Howard Gorman, President, HSG Group, Inc.

Date: July 11, 2025

Response:

A. The amount of $331,178 on Schedule C1-5, line 45, for FTY 2025, represents the total Rate Cass expense the Company expects to incur. The details have been previously provided, appearing on the Company's response I&E-RE-1 Attachment A, on tab C1-3, cells M29:O37. They are repeated below for convenience.

McNees fully litigated		180,000
HSG Group	Fixed	100,000
HSG Group	Travel	3,000
ScottMadden	Initial	11,667
ScottMadden	Additional	25,000
BKD		2,000
Prior overcollection		(489)
Printing, other		10,000
		331,178

The amount of $331,178 is included in the total $35,399 on Schedule C1-5, line 9, for FTY 2025.

B. The amount of $275,981 on Schedule C1-5, line 25, for FPFTY 2026, is computed as follows:

Rate Case expense incurred	$331,178
50% of 2026 amortization	(55,197)
Average balance for FPFTY 2026	$275,981

The amortization period is 3 years, equal to annual amortization of $110,393, and 50% of that is $55,197.
The amount of $275,981 is included in the total ($19,798) on Schedule C1-5, line 9, for FPTFY 2025.

C. Yes.

D. As discussed in part B, this represents the average balance during the FPFTY 2026.

E. Rate case expense is a cost the Company must incur to have rates that allow it to recover its costs, which are necessary to provide service. As with any asset, the Company needs to recover both the cost of the asset, and the carrying cost of the unrecovered funds expended to obtain the asset.

WELLSBORO ELECTRIC COMPANY
DOCKET NO. R-2025-3054392

I&E-RE-10-D

Reference Company Exhibit HSG-1, Schedule C1-1. For each of the following, provide details by year identifying the account name/number, the payee(s), the expense amount claimed in HTY 2024, FTY 2025, and FPFTY 2026, and the basis for why each expense is appropriate to include for ratemaking purposes:

A. Fines and penalties.
B. Bank charges.
C. Clearinghouse fees.
D. Subscriptions.
E. Company sponsorships.
F. Lobbying expenses/Political campaign donations.
G. Membership dues and subscriptions.
H. Donations.
I. Charitable or civic contributions.

Response Provided By:
Jill L. Campbell, VP of Finance and Administration, Wellsboro Electric Company

Date: June 3, 2025

Response: See chart below

		2024	2025	2026
A.	Fines & Penalties	-	-	-
B.	Bank Charges	5,134	6,000	6,000
C.	Clearinghouse Fees	-	-	-
D.	Subscriptions	2,961	3,400	3,400
E.	Company Sponsorships	-	-	-
F.	Lobbying Expenses/Political Campaign Donations	29	32	32
G.	Membership Dues & Subscriptions	3,372	3,372	3,372
H.	Donations	-	-	-
I.	Charitable or Civic Contributions	-	-	-

A. None
B. Bank fees are incurred in the normal course of business for managing customer payments and processing transactions. These services help to maintain reliable and secure financial practices that ultimately benefit the ratepayers. To ensure that fees remained competitive, in 2021 the Company solicited proposals from multiple banking institutions and based on that evaluation the selected banking partner offered the most cost -effective solution which demonstrates the Company's commitment to prudent financial management and controlling costs on the customer's behalf.

C. None
D. Subscriptions are used to support operational efficiency, streamline administrative tasks and enhance overall productivity. Professional subscriptions are used to access up to date industry information. These tools enable staff to work more effectively.
E. None
F. A small portion of industry association dues are designated for lobbying activities conducted by the association and not through direct lobbying efforts by the Company.
G. Membership dues to industry associations provide access to critical regulatory updates, best practices, and training opportunities. These resources help the Company's ability to manage its operations effectively while staying compliant with evolving regulations.
H. None
I. None

WELLSBORO ELECTRIC COMPANY
DOCKET NO. R-2025-3054392

I&E-RE-12-D

Reference Wellsboro Exhibit HSG-1, Schedule C1-1, p. 1, regarding Miscellaneous Distribution Expense (Account 588). Provide the following:

A. A detailed breakdown for the Miscellaneous Distribution account: 2023 - $170,671; HTY 2024 - $173,944; FTY 2025 - $280,422; FPFTY 2026 - $285,688.
B. A detailed explanation for the 61.2% [(106478 ÷ $173,944) x 100] projected increase between HTY 2024 and FTY 2025.

Response Provided By:
Jill L. Campbell, VP of Finance and Administration, Wellsboro Electric Company

Date: June 3, 2025

Response:

	2023	2024	2025	2026
General	12,886	14,556	31,450	31,450
Labor	86,318	91,107	136,556	140,466
OH	71,468	67,581	112,416	113,772
Transportation	-	699	-	-
Materials	-	-	-	-
	170,671	**173,944**	**280,422**	**285,688**

Labor costs have increased compared to prior years primarily due to a vacant General Utility position temporarily reducing labor costs during the vacancy. Responsibilities for that position have been realigned across departments and duties were redistributed to ensure adequate coverage subsequently increasing labor and overhead costs for this category in future budget years.

WELLSBORO ELECTRIC COMPANY
DOCKET NO. R-2025-3054392

I&E-RE-13-D

Reference Wellsboro Exhibit HSG-1, Schedule WP-C2, p. 1, regarding Miscellaneous Distribution Expense (Account 588) provide the following:

A. A detailed breakdown for the Miscellaneous Distribution Expense labor costs: 2023 - $86,318; HTY 2024 - $91,107; FTY 2025 - $136,556; FPFTY 2026 - $140,466.
B. A detailed explanation for the 49.9% [{($136,556 - $91,107) ÷ $91,107} x 100] projected increase between HTY 2024 and FTY 2025.
C. A detailed breakdown for the Miscellaneous Distribution Expense overhead costs: 2023 - $71,468; HTY 2024 - $67,581; FTY 2025 - $122,066; FPFTY 2026 - $123,422.
D. A detailed explanation for the 80.6% [{($122,066 - $67,581) ÷ $67,581} x 100] projected increase between HTY 2024 and FTY 2025.

Response Provided By:
Jill L. Campbell, Vice President of Finance and Administration, Wellsboro Electric Company

Date: June 3, 2025

Response:

See response to I&E-RE-12-D.

KPMG

TaxNewsFlash

United States

No. 2022-193
July 11, 2022

Pennsylvania: Changes to corporate net income tax laws, other tax changes

House Bill 1342 was signed into law in Pennsylvania on July 8, 2022. The bill makes significant changes to the Commonwealth's corporate net income tax laws, as discussed below.

Corporate net income tax rate reduction

The Commonwealth's current corporate net income tax rate is 9.99%, which is one of the highest in the country. House Bill 1342 reduces that rate incrementally to 4.99%. These rate reductions are scheduled to occur automatically and are not contingent on state tax revenues meeting or exceeding specific thresholds.

The rate is first reduced to 8.99% for the 2023 tax year—the tax year beginning on or after January 1, 2023 through December 31, 2023. The rate is further reduced as follows:

- 8.49% for tax year 2024
- 7.99% for tax year 2025
- 7.49% for tax year 2026
- 6.99% for tax year 2027
- 6.49% for tax year 2028
- 5.99% for tax year 2029
- 5.49% for tax year 2030
- 4.99% for tax years beginning January 1, 2031 and thereafter

KPMG observation

Previous corporate net income rate reductions were included in bills that would also have adopted unitary combined reporting. However, unitary combined reporting is not included in this legislation.

Sales factor changes

Under current law, specific sourcing rules apply to receipts from sales of services and receipts from sales of tangible personal property. All other receipts are sourced under the statutory income-producing activity test and

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are included in the Pennsylvania sales factor numerator if the income-producing activity is performed in Pennsylvania, or if a greater proportion of the income-producing activity is performed in Pennsylvania, based on costs of performance. House Bill 1342 adopts comprehensive customer-based sourcing rules for a number of "other" types of receipts, including:

- Gross receipts from the lease or license of intangible property
- Gross receipts from sales of intangibles
- Gross receipts from the sale, redemption, maturity or exchange of securities held by a taxpayer primarily for sale to customers
- Gross receipts related to lending activities involving real property and tangible personal property
- Gross receipts received from interest, fees, and penalties from credit card holders
- Gross receipts received from interest not otherwise addressed in the revised law

Any gross receipts associated with intangible property that are not specifically addressed will be excluded from both the numerator and denominator of the sales factor. The state tax authority is directed to promulgate rules and regulations to implement the new sourcing rules, which are effective for tax years beginning after December 31, 2022.

KPMG observation

There is ongoing litigation in Pennsylvania over the application of the income-producing activity test as applied to service receipts. The *Synthes* case, currently pending before the Pennsylvania Supreme Court, involves the interpretation of the statutory income-producing activity test in years prior to 2014 before the legislature revised the law to provide that service receipts are sourced to the location where the services are delivered. In *Synthes*, the state tax authority and the taxpayer were on the same side and argued that the tax authority's market-based interpretation of the income-producing activity test, which resulted in a refund for Pennsylvania-based taxpayer, was entitled to deference. The Attorney General, however, disagreed that the tax authority's interpretation was entitled to deference. The Commonwealth Court held in favor of the taxpayer and the tax authority, the Attorney General appealed to the Pennsylvania Supreme Court, and oral arguments were held in March 2022. Although *Synthes* involves service receipts, the outcome may be instructive as to application of the income-producing activity test to other types of receipts for years prior to 2023.

Codification of economic nexus standards

House Bill 1342 codifies Corporation Tax Bulletin 2019-04, issued post-*Wayfair*, in which the state tax authority announced that for tax years beginning on or after January 1, 2020, corporations meeting an economic nexus standard would be required to file corporate net income tax returns (unless protected under Public Law 86-272). The bulletin set forth a rebuttable presumption that a corporate taxpayer without a physical presence in Pennsylvania that had $500,000 or more of direct or indirect gross receipts sourced to Pennsylvania from any combination of (1) gross receipts from the sale, rental, lease, or licensing of tangible personal property; (2) gross receipts from the sale of services; or (3) gross receipts from the sale or licensing of intangibles, including franchise agreements, would have a filing responsibility.

Effective for tax years beginning after December 31, 2022, House Bill 1342 codifies the rebuttable presumption that a corporation with $500,000 or more of receipts sourced to Pennsylvania will have substantial nexus with the Commonwealth, despite the lack of a physical presence. However, an exception applies to affiliated entities domiciled in foreign nations that have entered into comprehensive income tax treaties with the United States. The treaties must provide "for the allocation of all categories of income subject to taxation, or the withholding of tax, on royalties, licenses, fees and interest for the prevention of double taxation of the respective nations' residents and the sharing of information."

KPMG observation

It is important to consider the economic nexus standard in conjunction with the revised sourcing rules that apply

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beginning with the 2023 tax year. A taxpayer that previously sourced receipts under the income-producing activity test may not have had the requisite level of receipts sourced to the Commonwealth. However, that may no longer be the case when those receipts are sourced using the new customer-based rules.

Sales and use tax and other tax changes

Effective January 1, 2023, House Bill 1342 requires peer-to-peer car sharing marketplace facilitators (as defined) to collect sales and use tax on facilitated shared vehicle rentals. The up-to-$2 per day fee that applies to vehicle rentals is extended to vehicles rented as part of a peer-to-peer car sharing program. However, the Commonwealth's 2% vehicle rental tax does not apply to a shared vehicle that is rented through a peer-to-peer car sharing program. The bill also extends the computer data center sales tax exemption qualification period from 15 years to 25 years for qualified purchases of equipment installed in the computer data center.

For individual (personal) income tax purposes, effective for tax years beginning after December 31, 2022, the bill conforms the Commonwealth to the section 179 expensing provisions and the section 1031 deferral provisions. A new refundable tax credit is adopted for eligible taxpayers who receive the federal child and dependent care tax credit. Finally, the bill increases the annual cap for the research and development and film production tax credits and makes certain changes to the keystone opportunity zone provisions.

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I&E Statement No. 1-SR
Witness: Zachari Walker

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

WELLSBORO ELECTRIC COMPANY

Docket No. R-2025-3054392

Surrebuttal Testimony

of

Zachari Walker

Bureau of Investigation and Enforcement

Concerning:

OPERATING AND MAINTENANCE EXPENSES

STATE INCOME TAX EXPENSE

RATE BASE

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INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Zachari Walker, and my business address is Pennsylvania Public Utility Commission, Commonwealth Keystone Building, 400 North Street, Harrisburg, PA 17120.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by the Pennsylvania Public Utility Commission (Commission or PUC) in the Bureau of Investigation & Enforcement (I&E) as a Fixed Utility Financial Analyst.

Q. ARE YOU THE SAME ZACHARI WALKER WHO SUBMITTED I&E STATEMENT NO. 1 AND I&E EXHIBIT NO. 1?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR SURREBUTTAL TESTIMONY?

A. The purpose of my surrebuttal testimony is to respond to the rebuttal testimony of Wellsboro Electric Company (Wellsboro or Company) witnesses Howard Gorman[1] and Jill Campbell.[2] I also present I&E's updated position based on my

[1] Wellsboro Statement No. 1-R.
[2] Wellsboro Statement No. 5-R.

updated recommended operating and maintenance (O&M) expense adjustments and the updated adjustments of the other I&E witnesses.

Q. DOES YOUR SURREBUTTAL TESTIMONY INCLUDE AN EXHIBIT?

A. No. However, I reference my direct testimony and accompanying exhibit as I&E Statement No.1 and I&E Exhibit No. 1, respectively.

EFFECTIVE DATE OF NEW RATES

Q. WHAT IS THE EFFECTIVE DATE PROPOSED FOR NEW RATES?

A. The Company indicates that its effective date for new rates is January 30, 2026, however, the rate change could be effective earlier if the parties agree to a settlement that includes an accelerated effective date and that settlement is approved by the Commission.[3]

Q. SUMMARIZE YOUR DIRECT TESTIMONY REGARDING WHETHER NEW RATES SHOULD BE ALLOWED TO GO INTO EFFECT PRIOR TO THE JANUARY 30, 2026 EFFECTIVE DATE.

A. As stated in my direct testimony, rates should not go into effect prior to the beginning of the fully projected future test year (FPFTY) which is January 1, 2026. This date is the beginning of the twelve-month period on which new rates

[3] Wellsboro Statement No. 1, p. 2.

are based. For this reason, it would be unjust and unreasonable for ratepayers to pay the increase in rates prior to the beginning of the first day of the FPFTY.[4]

Q. DID ANY WITNESS RESPOND TO YOUR RECOMMENDATION?

A. No.

SUMMARY OF COMPANY'S UPDATED REQUEST

Q. SUMMARIZE THE COMPANY'S UPDATED REQUESTED REVENUE INCREASE.

A. In rebuttal testimony, the Company updated its requested revenue increase to $2,848,804 to the updated claimed present rates revenues of $6,696,602 resulting in an overall revenue requirement of $9,545,406.[5]

Q. SUMMARIZE YOUR RECOMMENDED ADJUSTMENTS TO THE COMPANY'S REBUTTAL POSITION.

A. The following table summarizes my updated recommended adjustments:

[4] I&E Statement No. 1, p. 3.
[5] Wellsboro Exhibit HSG-1-R, Schedule C1-R.

	Wellsboro FPFTY Claim	I&E Recommended Allowance	I&E Adjustment
O&M Expenses:			
Rate Case Expense	$110,393	$66,236	($44,157)
Membership Dues and Subscriptions	$12,804	$9,365	($3,439)
Miscellaneous Distribution Expense	$285,688	$278,888	($6,800)
Total O&M Adjustments			**($54,396)**
Rate Base Adjustments:			
Unamortized Rate Case Expense	$275,981	$0	($275,981)
Cash Working Capital	$512,714	$505,914	($6,800)
Total Rate Base Adjustments			**($282,781)**

Q. HAS THE COMPANY ACCEPTED ANY OF YOUR RECOMMENDED ADJUSTMENTS FROM DIRECT TESTIMONY?

A. Yes. The Company accepted my recommendation to use the correct tax rate, 7.49%,[6] to calculate the FPFTY corporate state income tax expense.[7]

SUMMARY OF I&E OVERALL UPDATED POSITION

Q. WHAT IS I&E'S UPDATED RECOMMENDED REVENUE REQUIREMENT?

A. I&E's recommended revenue requirement for Wellsboro is $9,299,442. This recommended revenue requirement represents an increase of $2,602,840 to the updated claim for present rate revenues of $6,696,602. This total recommended

[6] I&E Statement No. 1, pp. 22-23.
[7] Wellsboro Statement No. 1-R, p. 3.

allowance incorporates my adjustments made in this testimony to O&M expenses, taxes, and rate base, and those made in the testimony of I&E witness Christopher Keller.[8]

An updated calculation of the I&E recommended revenue requirement is shown in the table below:

Wellsboro Electric Company		TABLE I			
R-2025-3054392		INCOME SUMMARY			
	12/31/26	INVESTIGATION & ENFORCEMENT			
	Proforma	[			]
	Present Rates	Adjustments	Present Rates	Allowances	Proposed
	$	$	$	$	$
Operating Revenue	6,696,602	0	6,696,602	2,602,840	9,299,442
Deductions:					
O&M Expenses	4,292,779	-54,396	4,238,383	0	4,238,383
Depreciation	1,939,404	0	1,939,404		1,939,404
Taxes, Other	419,926	0	419,926	153,568	573,494
Income Taxes:					
Current State	-64,035	4,529	-59,506	183,450	123,944
Current Federal	-166,090	11,749	-154,341	475,823	321,482
Deferred Taxes	109,094	0	109,094		109,094
ITC	0	0	0		0
Total Deductions	6,531,078	-38,118	6,492,960	812,841	7,305,801
Income Available	165,524	38,118	203,642	1,789,999	1,993,641
Measure of Value	25,974,028	-282,781	25,691,247	0	25,691,247
Rate of Return	0.64%		0.79%		7.76%

[8] I&E Statement No. 2.

RATE CASE EXPENSE

Q. SUMMARIZE YOUR RECOMMENDATION FOR RATE CASE EXPENSE AS PRESENTED IN YOUR DIRECT TESTIMONY.

A. I recommended that Wellsboro be required to normalize its rate case expense as opposed to amortizing it, since the Commission recognizes rate case expense as an ongoing expense occurring at irregular intervals, related to the rendering of utility service.[9] My recommended annual allowance for rate case expense of $66,236 was based on normalizing the Company's total claim over its historical average filing frequency of approximately 60 months as determined by the filing date of this rate proceeding and that of the Company's three most recent rate cases. My recommendation is consistent with the Commission's emphasis on the importance of considering the utility's history of rate case filings when determining the normalization period of rate case expenses. My recommended annual rate case expense allowance of $66,236 represented a reduction of $44,157 ($110,393 - $66,236) to the Company's FPFTY claimed rate case expense.[10]

Q. DID ANY WITNESS RESPOND TO YOUR RECOMMENDATION?

A. Yes. Wellsboro witness Howard Gorman disagrees with my recommendation.

[9] I&E Statement No. 1, p. 9.
[10] I&E Statement No. 1, pp. 8-13.

Q. SUMMARIZE WITNESS GORMAN'S RESPONSE.

A. Mr. Gorman contends that Wellsboro's normalization period should be determined based on the Company's anticipated three-year period between base rate filings rather than the historical average filing frequency. According to Mr. Gorman, Wellsboro was able to avoid filing a rate case in 2022 due to abnormal load growth and the Company's participation in temporary funding programs available during the COVID-19 pandemic, both of which are not forecasted to occur again going forward. Mr. Gorman also notes that Wellsboro's sister company, Citizens' Electric Company of Lewisburg, PA (Citizens'), proposed a three-year normalization period and did not receive objection to that proposal from other parties to that case.[11]

Q. WHAT IS YOUR RESPONSE TO MR. GORMAN'S TESTIMONY CONCERNING RATE CASE EXPENSE?

A. First, Mr. Gorman did not directly address my recommendation that Company be required to normalize its rate case expense claim rather than be allowed to amortize it; however, he does state that Wellsboro proposed normalizing its rate case expense claim over 36 months.[12] Presumably, Mr. Gorman is accepting normalization treatment for the Company's rate case expense.

[11] Wellsboro Statement No. 1-R, p. 4.
[12] Wellsboro Statement No. 1-R, p. 4.

Next, I am also the I&E witness reviewing Citizens' base rate filing, so I can state that the reason I did not propose an alternate normalization period in that proceeding is because Citizens' historical average filing frequency aligned with the Company's proposed normalization period. His argument against using a historical average filing frequency to determine the annual rate case expense allowance is the very reason why this method is appropriate. Using the historical average filing frequency to determine the interval over which to normalize rate case expenses provides protection for ratepayers from potentially significant over-recoveries of expenses in rates when the expense occurs less frequently than anticipated.

If the Company begins to file rate cases on a shorter regular filing interval, that new regular filing interval will naturally align with the historical average filing frequency. Until such time as that occurs, normalization protects the customers from being overcharged in rates for rate case expense if the anticipated regular filing interval does not occur.

Wellsboro has not historically demonstrated that it is likely to file its next base rate case within 36 months of the instant filing, and therefore, my recommendation to normalize rate case expense over the historic filing frequency is more appropriate.

Q. DO YOU HAVE ANY CHANGES TO YOUR RECOMMENDATION FOR RATE CASE EXPENSE?

A. No. I continue to recommend that the Company's rate case expense be normalized over the historical average filing frequency interval of 60 months. The result is my recommended annual expense allowance of $66,236 for rate case costs, a reduction of $44,157 to the Company's claim. My recommendation is consistent with the Commission's emphasis on the importance of considering the utility's history of rate case filings when determining the normalization period of rate case expenses.

UNAMORTIZED RATE CASE EXPENSE IN RATE BASE

Q. SUMMARIZE YOUR RECOMMENDATION FOR UNAMORTIZED RATE CASE EXPENSE IN RATE BASE AS PRESENTED IN YOUR DIRECT TESTIMONY.

A. I recommended the entire rate base claim of $275,981 for unamortized rate case expense be disallowed for ratemaking purposes based on my recommendation to normalize Wellsboro's total O&M claim for rate case expense. Normalization transforms an irregularly-recurring, routine operating expense into a "normal" annual test year expense. Normalization also addresses the prospective recovery of an ongoing expense that recurs sporadically and gives the Company the opportunity to achieve full recovery of rate case costs. However, if the Company were allowed to include a claim for unamortized rate case expense in rate base,

along with capturing an amount on the expense side, it would earn a return on and a return of rate case expense. Any allowance for return on an expense, in addition to a return of such an expense, is not an appropriate ratemaking practice.[13]

Q. DID ANY WITNESS RESPOND TO YOUR RECOMMENDATION?

A. Yes. Wellsboro witness Howard Gorman disagrees with my recommendation.

Q. SUMMARIZE WITNESS GORMAN'S RESPONSE.

A. Mr. Gorman opines that allowing the Company to earn a return on the balance of unamortized rate case expense compensates the Company for the delay between paying the rate case expenses costs and receiving post-proceeding distribution revenues over the normalization period. He additionally contends that rate case expense is equivalent to the inclusion of purchased materials and supplies in rate base prior to their use.[14]

Q. WHAT IS YOUR RESPONSE TO MR. GORMAN'S ASSERTION?

A. First, Mr. Gorman's conflates purchasing physical materials and supplies and the costs incurred to conduct a rate case, typically mailings and payment for contracted services. In one instance, inventories are held on hand as an asset until used in the normal course of business; on the other hand, the costs experienced to

[13] I&E Statement No. 1, pp. 8-12.
[14] Wellsboro Statement No. 1-R, p. 5.

conduct a rate case are incurred during the rate proceeding for which the Company previously received an embedded normalized expense in distribution revenues to fund. The normalization process is to fund rate case expenses prospectively between occurrences, not to reimburse current rate case expenses after the fact. This methodology further reinforces my position that any rate base treatment of current expenses is highly inappropriate as the Company received revenues designated for the current case in the years that have elapsed since the prior rate case. If rate base treatment were allowed, then the logical counter to that is that the Company should have been building a regulatory liability for ratepayer funds received via rate case expense during all the intervening years as an offset to the current expenses claimed as a regulatory asset. Clearly that is not the intent for a regularly recurring, non-extraordinary.

Given Mr. Gorman's presumed acceptance of my recommendation in direct testimony as stated in the rate case expense section above,[15] it is not appropriate to also request amortization treatment for rate case expenses.

Normalization is the appropriate ratemaking treatment for rate case costs. The ratemaking practice of normalization does not include any provision for a remaining balance nor allow for a remaining balance to be captured in rate base. Rate case expense represents a routine operating expense which is not extraordinary in nature.

[15] I&E Statement No. 1-SR, p. 7.

Q. DO YOU HAVE ANY CHANGE TO YOUR RECOMMENDATION?

A. No. For the reasons explained above and in my direct testimony, I continue to recommend that the Commission disallow the Company's claimed $275,981 unamortized rate case expense in rate base for the FPFTY.

MEMBERSHIP DUES AND SUBSCRIPTIONS

Q. SUMMARIZE YOUR RECOMMENDATION FOR MEMBERSHIP DUES AND SUBSCRIPTIONS IN YOUR DIRECT TESTIMONY.

A. I recommended disallowing the entire $12,804 membership dues and subscriptions claims for ratemaking purposes based on the lack of support for the identified expenses.[16]

Q. DID ANY WITNESS RESPOND TO YOUR RECOMMENDATION?

A. Yes. Wellsboro witness Jill Campbell disagrees with my recommendation.

Q. SUMMARIZE MS. CAMPBELL'S RESPONSE.

A. Ms. Campbell opines the table included in her rebuttal testimony, with payee and account details, fully supports the Company's claim for membership dues and subscription.[17]

[16] I&E Statement No. 1, p. 16.
[17] Wellsboro Statement No. 5-R, p. 2.

Q. WHAT IS YOUR RESPONSE TO MS. CAMPBELL'S REBUTTAL TESTIMONY REGARDING MEMBERSHIP DUES AND SUBSCRIPTIONS?

A. The additional information provided in Ms. Campbell's testimony makes it possible to determine which of the included claims are appropriate to include for ratemaking purposes.[18]

Q. DO YOU HAVE ANY CHANGES TO YOUR RECOMMENDATION?

A. Yes. Based on the additional details provided in the Company's rebuttal testimony, I am updating my recommendation. The chart below illustrates my updated position regarding the Company's membership dues and subscriptions claims:

Vendor Description	**Company FPFTY Claim**	**I&E Recommended Allowance**	**I&E Recommended FPFTY Adjustment**
C&N Bank	$6,000	$6,000	$0
Handy-Whitman Index	$175	$175	$0
Wellsboro Gazette	$100	$65	($35)
Adobe Pro for Teams Subscription	$1,900	$1,900	$0
Notary Fees	$1,050	$1,050	$0
Zoom Subscription	$175	$175	$0
Energy Assoc. – Subscription	$957	$0	($957)
PA Chamber of Business & Industry	$1,450	$0	($1,450)
Voam	$190	$0	($190)
Wellsboro Chamber of Commerce	$775	$0	($775)
Energy Assoc. – Lobbying Expenses	$32	$0	($32)
Total	$12,804	$9,365	($3,439)

[18] Wellsboro Statement No. 5-R, p. 2.

I accept the claims for bank charges, notary fees, and Handy Whitman Index[19] for ratemaking purposes. Likewise, after checking the advertised subscription fees, the claimed amounts for Adobe Pro for Teams[20] and Zoom[21] are reasonable and appropriate for ratemaking consideration.

Next, I recommend the $190 claim for Voam be disallowed entirely as it is unclear what benefit this provides to ratepayers; to that point, the $190 claim is unsupported and therefore inappropriate to include for ratemaking purposes.

Also, I recommend the membership dues and subscriptions claim of $775 for the Wellsboro Chamber of Commerce (Wellsboro Chamber) be disallowed for ratemaking purposes. Upon reviewing Wellsboro Chamber's website, it appears this membership does not provide benefits to ratepayers.[22]

Finally, I recommend the claims for Energy Association of PA (EAP) lobbying expenses of $32, EAP membership dues and subscriptions of $957, and PA Chamber of Business and Industry (PA Chamber) membership dues and subscriptions of $1,450 be disallowed for ratemaking purposes because they represent expenditures for political advertising as described in the following:

66 Pa. C.S. § 1316(a) states that "[f]or purposes of rate determinations, no public utility may charge to its consumers as a permissible operating expense for ratemaking purposes any direct or indirect expenditure by the utility for political

[19] Wellsboro Statement No. 5-R, p. 2.
[20] Acrobat for business pricing & plans | Adobe Acrobat, accessed August 20, 2025.
[21] Plans & Pricing for Zoom Workplace | Zoom, accessed August 20, 2025.
[22] Home - Wellsboro Area Chamber of Commerce | PA, accessed August 20, 2025.

advertising."[23] 66 Pa. C.S. § 1316(d) states:

> As used in this section the term "political advertising" means any advertising for the purpose of influencing public opinion with respect to any legislative, administrative action, or candidate election or with respect to any controversial issue to be decided by public voting. The term includes money spent for lobbying but not money spent for appearances before regulatory or other governmental bodies in connection with a public utility's existing or proposed operations.[24]

Q. HOW DID YOU DETERMINE THESE CLAIMS ARE EXPENDITURES FOR POLITICAL ADVERTISING?

A. According to EAP's website, "[EAP] is an advocate for its members on policy issues before the General Assembly, the PUC, and various other state governmental agencies."[25] Any funds paid to EAP likely represent the Company's intent to have EAP influence policy issues in favor of Wellsboro. Therefore, the Company's claims are inappropriate for ratemaking purposes, and I recommend the EAP claims of $957 and $32 be disallowed for ratemaking purposes.

As stated on the PA Chamber's website, "the Chamber serves as the frontline advocate for business on Capitol Hill in Harrisburg…through lobbying, testifying, developing key relationships…promot[ing] pro-business legislation, and fight[ing] anti-business legislation…"[26] Similar to the EAP costs above, this $1,450 PA Chamber expense claim represents political advertising or lobbying costs and is not appropriate expenses to include for ratemaking purposes. As a

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[23] 66 Pa. C.S. § 1316(a).
[24] 66 Pa. C.S. § 1316(d).
[25] Who We Are | Energy Association of PA, accessed August 20, 2025.
[26] Advocacy - PA Chamber, accessed August 20, 2025.

result, I recommend the PA Chamber claim be disallowed for ratemaking purposes.

MISCELLANEOUS DISTRIBUTION EXPENSE

Q. SUMMARIZE YOUR RECOMMENDATION FOR MISCELLANEOUS DISTRIBUTION EXPENSE IN YOUR DIRECT TESTIMONY.

A. I recommended the entire $285,688 FPFTY claim be disallowed for ratemaking purposes based on a lack of sufficient support for the miscellaneous distribution expense is necessary for the safe and reliable supply of electric service and subsequently appropriate for ratemaking purposes.[27]

Q. DID ANY WITNESS RESPOND TO YOUR RECOMMENDATION?

A. Yes. Wellsboro witness Jill Campbell disagrees with my recommendation.

Q. SUMMARIZE MS. CAMPBELL'S RESPONSE.

A. Ms. Campbell provides a detailed breakdown of the miscellaneous distribution expense account, explaining that the proposed increase in future costs is due to a previous vacancy in 2024, a rebalancing of capitalized versus expensing labor following a realignment of responsibilities among existing staff to cover the 2024 vacancy, and an increase in training, safety and labor costs to develop apprentices

[27] I&E Statement No. 1, pp. 17-19.

and journeymen. [28] At one point, Ms. Campbell also opines that part of the Company's increased expense level represents a contingency for repair of customer property, tree replacement, and other expenses.[29]

Q. DO YOU HAVE ANY CHANGES IN YOUR RECOMMENDATION IN RESPONSE TO MS. CAMPBELL'S EXPLANATION?

A. Yes. After reviewing Ms. Campbell's rebuttal testimony, the projections presented, and investigating corresponding historical miscellaneous distribution expense levels, I accept that most of the projected expense level is reasonable; however, the proposed allowance for customer property repair, miscellaneous distribution expense subaccount 588.00, of $6,800 is unsupported. In fact, the Company has incurred a net negative cost for customer property repairs over the most recent historical two years.[30] It is also inappropriate to build a contingency for damage to customers' property into the revenue requirement for ratemaking purposes. Therefore, I recommend that the claim miscellaneous distribution expense of $6,800 related to the contingency for damage to customers' property be disallowed for ratemaking purposes. This represents my recommended allowance of $278,888 ($285,688- $6,800) for FPFTY miscellaneous distribution expenses.

[28] Wellsboro Statement No. 5-R, pp. 2-5.
[29] Wellsboro Statement No. 5-R, p. 4.
[30] Wellsboro Statement No. 5-R, p. 3.

CASH WORKING CAPITAL (CWC)

Q. SUMMARIZE YOUR RECOMMENDATION IN DIRECT TESTIMONY FOR CWC.

A. I recommended an allowance of $474,913 or a reduction of $42,831 ($517,744 - $474,913) to the Company's claim. My recommendation was based on the 1/8th method in line with the Company's calculation method and reflected all my adjustments to O&M expenses as presented in direct testimony.[31] My recommendation was calculated as follows:

Company's CWC Claim		$517,744
I&E Recommended O&M Expense Adjustments	($342,649)	
1/8 of Total O&M Adjustments		($42,831)
I&E Recommended CWC Allowance		$474,913

Q. DID ANY WITNESS RESPOND TO YOUR RECOMMENDATION?

A. Yes. Wellsboro witness Howard Gorman disagrees with my recommended CWC allowance in as much as the Company witnesses disagree with my recommended adjustments.[32]

Q. DID THE COMPANY UPDATE ITS CWC CLAIM?

A. Yes. The Company's FPFTY CWC claim has been updated to $512,714.[33]

[31] I&E Statement No. 1, pp. 21-22.
[32] Wellsboro Statement No. 1-R, pp. 5-6.
[33] Wellsboro Exhibit HSG-1R, Schedule C1-5R.

Q. DO YOU AGREE WITH CITIZENS' UPDATED CWC CLAIM?

A. No.

Q. DO YOU HAVE ANY CHANGES TO YOUR RECOMMENDATION FOR CWC?

A. Yes. I am updating my CWC recommendation to reflect my updated recommended adjustments and the Company's updated CWC claim. My updated recommended CWC allowance is $505,914, or a reduction of $6,800 ($512,714 - $505,914) to the Company's updated FPFTY claim. This recommendation is calculated as follows.

Company's Updated CWC Claim		$512,714
I&E Updated Recommended O&M Expense Adjustments	($54,396)	
1/8 of I&E Updated Total O&M Adjustments		($6,800)
I&E Updated Recommended CWC Allowance		$505,914

Q. IS YOUR RECOMMENDED CWC ALLOWANCE A FINAL RECOMMENDATION?

A. No. All adjustments to the Company's claims for revenues, expenses, taxes, and rate base must be consistently brought together in the Administrative Law Judge's Recommended Decision and again in the Commission's Final Order. This process, which is known as iteration, effectively prevents the determination of a

precise calculation until such time as all adjustments have been made to the Company's claim.

Q. DOES THIS CONCLUDE YOUR SURREBUTTAL TESTIMONY?

A. Yes.

I&E Statement No. 2
Witness: Christopher Keller

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

WELLSBORO ELECTRIC COMPANY
Docket No. R-2025-3054392

&

CITIZENS' ELECTRIC COMPANY OF LEWISBURG, PA
Docket No. R-2025-3054394

Direct Testimony

of

Christopher Keller

Bureau of Investigation and Enforcement

Concerning:

Rate of Return

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INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Christopher Keller. My business address is Pennsylvania Public Utility Commission, Commonwealth Keystone Building, 400 North Street, Harrisburg, PA 17120.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by the Pennsylvania Public Utility Commission (Commission) in the Bureau of Investigation & Enforcement (I&E) as a Fixed Utility Financial Analyst.

Q. SUMMARIZE YOUR EDUCATION AND EMPLOYMENT HISTORY.

A. An outline of my education and employment history is attached as Appendix A.

Q. PLEASE DESCRIBE THE ROLE OF I&E IN RATE PROCEEDINGS.

A. I&E is responsible for protecting the public interest in proceedings before the Commission. I&E's analysis in this proceeding is based on its responsibility to represent the public interest. This responsibility requires balancing the interests of ratepayers, the regulated utility, and the regulated community as a whole.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to review the base rate filings of Wellsboro

Electric Company (Wellsboro) and Citizens' Electric Company of Lewisburg (Citizens'), collectively referred to in this testimony as "the Companies," and make recommendations regarding the Companies' rate of return, including capital structure, cost of long-term debt, cost of equity, and the overall fair rate of return for the fully projected future test year (FPFTY) ending December 31, 2026.

Q. DOES YOUR TESTIMONY INCLUDE AN EXHIBIT?

A. Yes. I&E Exhibit No. 2 contains schedules that support my direct testimony.

BACKGROUND

Q. WHAT IS THE GENERAL DEFINITION OF RATE OF RETURN IN THE CONTEXT OF A BASE RATE CASE?

A. Rate of return is one of the components of the revenue requirement formula. Rate of return is the amount of revenue an investment generates in the form of net income. It is typically expressed as a percentage of the amount of an asset base at a particular point in time, which in base rate proceedings, is the projected rate base balance at the end of the test year.

Q. WHAT IS THE REVENUE REQUIREMENT FORMULA?

A. The revenue requirement formula used in base rate cases is as follows:

$$RR = E + D + T + (RB \times ROR)$$

Where:

RR = Revenue Requirement

E = Operating Expenses

D = Depreciation Expense

T = Taxes

RB = Rate Base

ROR = Overall Rate of Return

In the above formula, the rate of return is expressed as a percentage. The calculation of that percentage is independent of the determination of the appropriate rate base value for ratemaking purposes. As such, the appropriate total dollar return is dependent upon the proper computation of the rate of return and the proper valuation of the company's rate base.

Q. WHAT CONSTITUTES A FAIR AND REASONABLE OVERALL RATE OF RETURN?

A. A fair and reasonable overall rate of return is one that will allow the utility an *opportunity* to recover those costs prudently incurred by all classes of capital used to finance the rate base during the prospective period in which its rates will be in effect. The Commission has the authority to determine the fair revenue requirement and rate of return, which the utility has the opportunity to earn, but is not guaranteed to earn.

The *Bluefield Water Works & Improvements Co. v. Public Service Comm. of West Virginia,* 262 U.S. 679, 692-93 (1923), and the *Federal Power Commission et al v. Hope Natural Gas Co.,* 320 U.S. 591, 603 (1944) cases set forth the principles

that are generally accepted by regulators throughout the country as the appropriate criteria for measuring a fair rate of return:

1. A utility is entitled to a return similar to that being earned by other enterprises with corresponding risks and uncertainties, but not as high as those earned by highly profitable or speculative ventures.
2. A utility is entitled to a return level reasonably sufficient to assure financial soundness.
3. A utility is entitled to a return sufficient to maintain and support its credit and raise necessary capital.
4. A fair return can change (increase or decrease) along with economic conditions and capital markets.

Q. EXPLAIN HOW THE OVERALL RATE OF RETURN IS TRADITIONALLY CALCULATED IN BASE RATE PROCEEDINGS.

A. In base rate proceedings, the overall rate of return is traditionally calculated using the weighted average cost of capital method. To calculate the weighted average cost of capital, a company's capital structure must first be determined by comparing the percentage of each capitalization component, which has financed rate base, to total capital. Next, the effective cost rate of each capital structure component must be determined. The historical component of the cost rate of debt can be computed accurately, and any future debt issuances are based on estimates. The cost rate of common equity is not fixed and is more difficult to measure.

Because of this difficulty, a proxy group is used as discussed later in this testimony. Next, each capital structure component percentage is multiplied by its corresponding effective cost rate to determine the weighted capital component cost rate. The I&E table in the *"I&E Position"* section below demonstrates the interaction of each capital structure component and its corresponding effective cost rate. Finally, the sum of the weighted cost rates produces the overall rate of return. This overall rate of return is multiplied by the rate base to determine the return portion of a company's revenue requirement.

COMPANIES' RATE OF RETURN CLAIM

Q. WHO ARE THE COMPANIES' RATE OF RETURN WITNESSES?

A. In the Companies' initial filing, Dylan W. D'Ascendis and Ryan M. Kucan were the primary witnesses that provided joint testimony addressing rate of return.[1] Subsequent to the initial filing, Mr. D'Ascendis and Mr. Kucan provided separate testimony where Mr. D'Ascendis provided testimony addressing the cost of common equity for the Companies and Mr. Kucan addressing the capital structure and long-term debt for the Companies. In my testimony, I will be referencing the Companies' subsequent testimony from Mr. D'Ascendis[2] and Mr. Kucan.[3] Additionally, Citizens' witness Nathan Johnson[4] and Wellsboro witness Byron

[1] As discussed at the prehearing conference held on June 3, 2025, the Companies were asked to submit revised testimony as the submission of written testimony sponsored by more than one witness violates Commission regulations. *See* 52 Pa. Code § 5.412.
[2] Citizens'/Wellsboro Statement No. 2.
[3] Citizens'/Wellsboro Statement No. 2A.
[4] Citizens' Statement No. 4.

Farnsworth, Jr.[5] provide testimony regarding the Companies' "Performance Factor Adjustment" claim.

Q. PLEASE SUMMARIZE THE COMPANIES' RATE OF RETURN CLAIMS.

A. Mr. D'Ascendis and Mr. Kucan recommend the following rate of return for the Companies based on the FPFTY ending December 31, 2026:[6]

Summary of Cost of Capital

Type of Capital	Ratio	Cost Rate	Weighted Cost
Citizens' Electric Company of Lewisburg			
Long-Term Debt	51.06%	5.47%	2.79%
Common Equity	48.94%	11.65%	5.70%
Total	100.00%		8.49%

Summary of Cost of Capital

Type of Capital	Ratio	Cost Rate	Weighted Cost
Wellsboro Electric Company			
Long-Term Debt	51.06%	4.85%	2.48%
Common Equity	48.94%	11.65%	5.70%
Total	100.00%		8.18%

[5] Wellsboro Statement No. 4.

[6] Citizens'/Wellsboro Filings, Exhibit (DWD-1), Schedule DWD-1, p. 1; Citizens'/Wellsboro Statement No. 2, p. 3, line 14 through p. 4, line 2; Citizens'/Wellsboro Statement No. 2A, p. 4, line 1 through line 4.

I&E POSITION

Q. PLEASE SUMMARIZE YOUR RATE OF RETURN RECOMMENDATION.

A. I recommend the following rate of return for the Companies:[7]

Type of Capital	Summary of Cost of Capital Ratio	Cost Rate	Weighted Cost
Citizens' Electric Company of Lewisburg			
Long-Term Debt	51.06%	5.47%	2.79%
Common Equity	48.94%	10.78%	5.28%
Total	100.00%		8.07%

Type of Capital	Summary of Cost of Capital Ratio	Cost Rate	Weighted Cost
Wellsboro Electric Company			
Long-Term Debt	51.06%	4.85%	2.48%
Common Equity	48.94%	10.78%	5.28%
Total	100.00%		7.76%

PROXY GROUP

Q. WHAT IS A PROXY GROUP AS USED IN BASE RATE CASES?

A. A proxy group is a set of companies that have similar traits in comparison to the subject utility. This group of companies acts as a benchmark for determining the subject utility's rate of return in a base rate case.

[7] I&E Exhibit No. 2, Schedule 1.

Q. WHAT ARE THE REASONS FOR USING A PROXY GROUP?

A. A proxy group's cost of equity is used as a benchmark to satisfy the long-established guideline of utility regulation that seeks to provide the subject utility with the opportunity to earn a return similar to that of enterprises with corresponding risks and uncertainties.

A proxy group is typically utilized since the use of data exclusively from one company may be less reliable. The lower reliability occurs because the data for one company may be subject to events that can cause short-term anomalies in the marketplace. The rate of return on common equity for a single company could become distorted in these circumstances and would therefore not be representative of similarly situated companies. Therefore, a proxy group has the effect of smoothing out potential anomalies associated with a single company.

Q. WHAT CRITERIA DID YOU USE IN SELECTING YOUR ELECTRIC UTILITY PROXY GROUP?

A. The criteria for my proxy group was designed to select companies that are representative of the Companies. I applied the following criteria to Value Line's East Electric Utility group:

1. Fifty percent or more of the company's revenues must be generated from the regulated electric utility industry.
2. The company's stock must be publicly traded.

3. Investment information for the company must be available from more than one source, which includes Value Line.

4. The company must not be currently involved in an announced merger or the target of an acquisition.

5. The company must have four consecutive years of historic earnings data.

6. The company must be operating in a state that has a deregulated electric utility market.

Q. WHAT CRITERIA DID MR. D'ASCENDIS USE IN SELECTING HIS ELECTRIC PROXY GROUP COMPANIES?

A. Mr. D'Ascendis determined his proxy group of fifteen electric companies by using the following criteria:[8]

1. The company is included in the East, Central, or West Electric Utility Group of Value Line's Standard Edition.

2. The company has 70% or greater of 2023 total operating income from, and 70% greater of 2023 total assets attributable to regulated electric operations.

3. At the time of the preparation of Mr. D'Ascendis' testimony, the company must not have publicly announced it was involved in any major merger or acquisition activity.

[8] Citizens'/Wellsboro Statement No. 2, p. 15, line 8 through p. 16, line 2.

4. The company must not have cut or omitted its common dividends during the five years ended 2023 or through the time of the preparation of Mr. D'Ascendis' testimony.

5. The company must have Value Line and Bloomberg Professional Services (Bloomberg) adjusted betas.

6. The company must have a positive Value Line five-year dividends per share (DPS) growth rate projection.

7. The company must have Value Line, Zacks, or S&P Capital IQ consensus five-year earnings per share (EPS) growth rate projections.

Q. WHAT PROXY GROUP DID YOU USE IN YOUR ANALYSIS?

A. I include the following nine companies in my proxy group:[9]

Dominion Energy	D
Duke Energy Corp.	DUK
Consolidated Edison Inc.	ED
Eversource Energy	ES
Exelon Corporation	EXC
FirstEnergy Corp.	FE
NextEra Energy Inc.	NEE
Public Service Enterprise Group Inc.	PEG
PPL Corporation	PPL

[9] I&E Exhibit No. 2, Schedule 2.

Q. WHAT PROXY GROUP DID MR. D'ASCENDIS USE IN HIS ANALYSIS?

A. Mr. D'Ascendis included the following fifteen companies in his Electric Group:[10]

Alliant Energy Corporation	LNT
Ameren Corp.	AEE
American Electric Power Company Inc.	AEP
Duke Energy Corp.	DUK
Edison International	EIX
Entergy Corp.	ETR
Evergy, Inc.	EVRG
IDACORP Inc.	IDA
NorthWestern Corporation	NWE
OGE Energy Corporation	OGE
Pinnacle West Capital Corporation	PNW
Portland General Electric Company	POR
Southern Company	SO
TXNM Energy, Inc.	TXNM
Xcel Energy Inc.	XEL

Q. DO YOU AGREE WITH MR. D'ASCENDIS' ELECTRIC PROXY GROUP?

A. No. While we do have one company that matches, I have eight companies that Mr. D'Ascendis does not and Mr. D'Ascendis includes fourteen companies that I do not.

[10] Citizens'/Wellsboro Exhibit (DWD-1), Schedule DWD-3, p. 1.

Q. PLEASE LIST THE COMPANIES MR. D'ASCENDIS HAS INCLUDED THAT YOU DO NOT AND EXPLAIN WHY YOU HAVE EXCLUDED IT FROM YOUR PROXY GROUP.

A. I have excluded all but Duke Energy Corp. from my proxy group. I excluded each of the remaining electric companies from Mr. D'Ascendis' electric group except Southern Company because they did not meet my criterion that they must be classified in the Electric Utility *East* group in The Value Line Investment Survey. I excluded Southern Company because it violates my sixth criterion as it does not operate in a state that has a deregulated electric utility market**.**

Q. YOU EXCLUDED SOUTHERN COMPANY FOR NOT OPERATING IN A STATE WITH A DEREGULATED MARKET. EXPLAIN WHAT IS MEANT BY A DEREGULATED ELECTRIC UTILITY MARKET.

A. A deregulated electric market is a market in which the utility is responsible only for the distribution of electricity, not generation. Deregulation permits electric suppliers to compete and sell electricity directly to consumers and allows consumers the ability to seek competitive rates.

Q. WHY DID YOU INCLUDE THE CRITERION THAT A COMPANY MUST OPERATE IN A STATE THAT HAS A DEREGULATED ELECTRIC UTILITY MARKET?

A. I included the criterion that a company must operate in a deregulated market, like

Pennsylvania, so that the companies included in my proxy group would all be of similar risk to the Companies. Unlike regulated markets, which contain largely vertically integrated utilities, deregulated markets permit electricity providers to compete and sell electricity directly to the consumers. This criterion helps to ensure that each company in the proxy group is operating in a similar market and under similar circumstances as the Companies. Furthermore, by virtue of the vertically integrated nature of regulated utilities, generation is owned and operated by the utility, which could place the companies in a substantially different risk profile based on the types and ages of generation plant owned and operated.

Q. PLEASE LIST THE COMPANIES YOU INCLUDE THAT MR. D'ASCENDIS DOES NOT AND EXPLAIN WHY HE HAS EXCLUDED THEM FROM HIS ELECTRIC GROUP.

A. The eight companies in question and the reasons for Mr. D'Ascendis' exclusion are as follows:

Company	Symbol	Criteria Violated from Above[11]
Dominion Energy	D	2 & 4
Consolidated Edison Inc.	ED	2
Eversource Energy	ES	2
Exelon Corporation	EXC	4 & 5
FirstEnergy Corp.	FE	3
NextEra Energy Inc.	NEE	2
Public Service Enterprise Group Inc.	PEG	2
PPL Corporation	PPL	4 & 6

[11] I&E Exhibit No. 2, Schedule 3.

All of the above except Exelon Corporation, FirstEnergy Corp., and PPL Corporation violated his second criterion that the company has 70% or greater of 2023 total operating income and 70% or greater of 2023 total assets attributable to regulated electric operations. FirstEnergy Corp. violated his third criterion that the company must not have publicly announced it was involved in any major merger or acquisition activity at the time of the preparation of his testimony. Dominion Energy, Exelon Corporation, and PPL Corporation violated his fourth criterion that the company must not have cut or omitted its common dividends during the five years ended 2023 or through the time of the preparation of his testimony. Exelon Corporation also violated his fifth criterion that the company must have Value Line and Bloomberg adjusted betas. Finally, PPL Corporation also violated his sixth criterion that the company must have a positive Value Line five-year DPS growth rate projection.

CAPITAL STRUCTURE

Q. WHAT IS A CAPITAL STRUCTURE?

A. A capital structure represents how a firm has financed its rate base with different sources of funds. The primary funding sources are long-term debt and common equity. A capital structure may also include preferred stock and/or short-term debt, which is not the case for the Companies.

Q. WHAT IS THE CLAIMED CAPITAL STRUCTURE USED BY THE COMPANIES'?

A. The Companies are proposing a hypothetical capital structure which is summarized in the table below:[12]

Type of Capital	Ratio
Long-Term Debt	51.06%
Common Equity	48.94%
Total	**100.00%**

Q. WHAT IS THE BASIS FOR THE COMPANIES' CLAIMED CAPITAL STRUCTURE?

A. Mr. Kucan's recommendation is based on the Companies' parent company C&T Enterprises' capital structure. He correctly explains that Citizens' and Wellsboro's actual equity ratios of 86.62% and 20.46%, respectively, are inappropriate for ratemaking purposes as they are not consistent with equity ratios of comparable utilities.[13]

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE COMPANIES' CAPITAL STRUCTURE?

A. I recommend using the Companies' claimed hypothetical capital structure as presented in the table above.

[12] Citizens'/Wellsboro Statement No. 2A, p. 4, lines 9-11.
[13] Citizens'/Wellsboro Statement No. 2A, p. 4, line 12 through, p. 5, line 4.

Q. WHAT IS THE BASIS FOR YOUR CAPITAL STRUCTURE RECOMMENDATION?

A. I agree with Mr. Kucan that the Companies' actual capital structures are unreasonable for ratemaking purposes. Although the Companies' proposed hypothetical capital structure falls outside the range of my proxy group's 2024 (most recent available) capital structures where the most recent five-year average range contains individual company capital structure ratios from 51.64% to 69.80% long-term debt and 30.20% to 48.36% equity, with an overall five-year average of 56.92% long-term debt and 42.49% common equity,[14] I recommend using the Companies' claimed hypothetical capital structure as I believe it is reasonable. Further, a capital structure that is closer to 50% long-term debt and 50% common equity is optimal when trying to balance the financial integrity of a utility, as well as trying to control costs to ratepayers, in this proceeding.

COST OF LONG-TERM DEBT

Q. WHAT IS THE COMPANIES' CLAIMED COST RATE OF LONG-TERM DEBT?

A. The Companies' claimed long-term debt cost rates are 5.47% and 4.85% for the FPFTY for Citizens' and Wellsboro, respectively.[15]

[14] I&E Exhibit No. 2, Schedule 2.
[15] Citizens'/Wellsboro Statement No. 2A, p. 5, lines 16-19.

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE COMPANIES' COST RATE OF LONG-TERM DEBT?

A. I recommend using the Companies' claimed long-term debt cost rates of 5.47% and 4.85% for the FPFTY for Citizens' and Wellsboro, respectively.

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATION TO USE THE COMPANIES' COST RATES OF LONG-TERM DEBT?

A. Although Citizens' falls outside my proxy group's implied long-term debt cost range of 3.09% to 5.30%, with an average implied long-term debt cost of 4.62% for 2024,[16] the Companies' cost rates of long-term debt are below the Mergent Bond Record average yield of 5.61% for the period May 2024 through April 2025 for A-rated public utility bonds.[17] I recommend that the Companies' cost rates of long-term debt be used since they are reasonable and fall within the metrics described above.

COST OF COMMON EQUITY

Common Methods

Q. WHAT METHODS ARE COMMONLY PRESENTED BY UTILITIES IN DETERMINING THE COST OF COMMON EQUITY?

A. Four methods commonly presented to estimate the cost of common equity are the

[16] I&E Exhibit No. 2, Schedule 4.
[17] I&E Exhibit No. 2, Schedule 5.

Discounted Cash Flow (DCF) Method, the Capital Asset Pricing Model (CAPM), the Risk Premium (RP) Method, and the Comparable Earnings (CE) Method.

Q. WHAT IS THE THEORETICAL BASIS FOR THE DCF METHOD?

A. The DCF method is the "dividend discount model" of financial theory, which maintains that the value (price) of any security or commodity is the discounted present value of all future cash flows. The DCF method assumes that investors evaluate stocks in the traditional economic framework, which maintains that the value of a financial asset is determined by its earning power, or its ability to generate future cash flows. The DCF method is also considered a forward-looking model to estimate the cost of common equity.

Q. WHAT IS THE THEORETICAL BASIS FOR THE CAPM?

A. The CAPM describes the relationship of a stock's investment risk and its market rate of return. It identifies the rate of return investors expect so that it is comparable with returns of other stocks of similar risk. This method hypothesizes that the investor-required return on a company's stock is equal to the return on a "risk free" asset plus an equity premium reflecting the company's investment risk. In the CAPM, two types of risk are associated with a stock: (1) firm-specific risk (unsystematic risk); and (2) market risk (systematic risk), which is measured by a firm's beta. The CAPM allows for investors to receive a return only for bearing

systematic risk. Unsystematic risk is assumed to be diversified away, and therefore, does not earn a return.

Q. WHAT IS THE THEORETICAL BASIS FOR THE RP METHOD?

A. The theoretical basis for the RP method is a simplified version of the CAPM. The RP method's theory is that common stock is riskier than debt, thus, investors require a higher expected return on stocks than bonds. In the RP approach, the cost of equity is made up of the cost of debt and a risk premium. While the CAPM uses the market risk premium, it also directly measures the systematic risk of a company group through the use of beta. The RP method does not measure the specific risk of a company.

Q. WHAT IS THE THEORETICAL BASIS FOR THE CE METHOD?

A. The CE method utilizes the concept of opportunity cost. This means that investors will likely dedicate their capital to the investment offering the highest return with similar risk to alternative investments. Unlike the DCF, CAPM, and the RP methods, the CE method is not market-based and relies upon historic accounting data. Similar to the RP method, the CE method does not measure the specific risk of a company. The most problematic issue with the CE method is determining what constitutes comparable companies.

Q. WHAT METHOD DO YOU RECOMMEND USING TO DETERMINE AN APPROPRIATE COST OF COMMON EQUITY FOR THE COMPANIES?

A. I recommend using the DCF method as the primary method to determine the cost of common equity. Additionally, I provide a CAPM analysis to be used as a comparison, not as a check, to the DCF results. The DCF method has the most wide-spread regulatory acceptance, and while the Commission has more recently based its ROE decisions on a combination of methods, I still recommend primary reliance on the DCF method due to the shortcomings associated with the CAPM method.

Q. PLEASE EXPLAIN WHY YOU CHOSE TO USE THE DCF TO DETERMINE YOUR RECOMMENDED RETURN ON EQUITY.

A. I have used the DCF for a variety of reasons. First, the DCF is appealing to investors as it is based upon the concept that the receipt of dividends in addition to the expected appreciation is the total return requirement determined by the market.[18] Second, the use of a growth rate and expected dividend yield are also strengths of the DCF, as this recognizes the time value of money and is forward-looking. Third, the use of the utilities' own, or in this case, the proxy group's stock prices and growth rates directly in the calculation also causes the DCF to be industry and company specific. Finally, current inflationary and economic trends are most certainly reflected in a stock's price, which is used in determining the

[18] David C. Parcell, "The Cost of Capital – A Practitioner's Guide," 2020 Edition, p. 153.

dividend yield, and by analysts who generate forecasted earnings growth rates. Therefore, the DCF contains the most up-to-date projected information of any model and is the superior method for determining the rate of return for the current economic market because it measures the cost of equity directly.

Q. PLEASE EXPLAIN WHY YOU CHOSE TO USE THE CAPM AS A COMPARISON TO THE DCF IN YOUR ANALYSIS.

A. I have included a CAPM analysis only as a comparison, and not as a basis, for my recommendation because both the CAPM and the DCF include inputs that allow the results to be specific to the utility industry. However, the CAPM is based on the performance of U.S. Treasury bonds and the performance of the market as measured through the S&P 500 and is company-specific only through the use of beta. Beta reflects a stock's volatility relative to the overall market, thereby incorporating an industry-specific aspect to the CAPM, but only as a measure of how reactive the industry is compared to the market as a whole. Although changes in the utility industry are more likely to be accurately reflected in the DCF, which uses the companies' actual prices, dividends, and growth rates, I have also included the results of my CAPM analysis because changes in the market, whether as a whole or specific to the utility industry, can affect the outcome of each method in different ways. Although I have provided the results of the CAPM as a comparison, and not as a check, it does have several disadvantages and should not be given comparable weight to the DCF method.

Q. EXPLAIN THE DISADVANTAGES OF THE CAPM.

A. The CAPM, and the RP method by virtue of its similarities to the CAPM, give results that indicate to an investor what the equity cost rate should be if current economic and regulatory conditions are the same as those present during the historical period in which the risk premiums were determined. This is because beta, which is the only company-specific variable in the CAPM model, measures the *historical* volatility of a stock compared to the *historical* overall market return. Reliance on historical values is especially problematic now given the recent events that have impacted economic conditions. Although the CAPM and RP results can be useful to investors in making rational buy and sell decisions within their portfolios, the DCF method is the superior method for determining the rate of return for the current economic market and measuring the cost of equity directly. The CAPM, and similarly the RP method, are less reliable indicators because they measure the cost of equity indirectly and risk premiums vary depending on the debt and equity being compared. Additionally, regulators can never be certain that economic and regulatory conditions underlying the historical period during which the risk premiums were calculated are the same today or will be the same in the future.

Q. IS THERE ANY ACADEMIC EVIDENCE THAT QUESTIONS THE CREDIBILITY OF THE CAPM MODEL?

A. Yes. An article, "Market Place; A Study Shakes Confidence in the Volatile-Stock

Theory," which appeared in the *New York Times* on February 18, 1992, summarized a CAPM study conducted by professors Eugene F. Fama and Kenneth R. French.[19] Their study examined the importance of beta, CAPM's risk factor, in explaining returns on common stock. In CAPM theory a stock with a higher beta should have a higher expected return. However, they found that the model did not do well in predicting actual returns and suggested the use of more elaborate multi-factor models.

A more recent article, "The Capital Asset Pricing Model: Theory and Evidence," which appeared in the *Journal of Economic Perspectives,* states that "the attraction of the CAPM is that it offers powerful and intuitively pleasing predictions about how to measure risk and the relation between expected return and risk. Unfortunately, the empirical record of the model is poor - poor enough to invalidate the way it is used in applications."[20] As a result, I conclude that the CAPM's relevance to the investment decision making process does not carry over into the regulatory rate setting process.

Q. PLEASE EXPLAIN WHY YOU HAVE CHOSEN TO EXCLUDE THE RP METHOD FROM YOUR ANALYSIS.

A. The RP method is excluded because it is a simplified version of the CAPM and is subject to the same faults explained above. The RP method has a number of

[19] Berg, Eric N. "Market Place; A Study Shakes Confidence in the Volatile-Stock Theory," *The New York Times*, February 18, 1992, *nytimes.com*, March 23, 2016.

[20] Fama, Eugene F. and French, Kenneth R., "The Capital Asset Pricing Model: Theory and Evidence." *Journal of Economic Perspectives* (2004): Volume 18, Number 3, pp. 25-46.

underlying assumptions and the most critical one, as well as the most disputed one, is the assumption that the equity risk premium is constant over the time.[21] More importantly, unlike the CAPM, the RP method does not recognize company-specific risk through beta.

Q. EXPLAIN WHY YOU HAVE CHOSEN TO EXCLUDE THE CE METHOD IN YOUR ANALYSIS.

A. The CE method is excluded because the choice of which companies are comparable is highly subjective, and it is debatable whether historic accounting values are representative of the future. Moreover, its historical usage in this regulatory forum has been minimal.

Q. HAVE YOU IDENTIFIED ANY SPECIFIC PROBLEMS WITH THE COMMISSION'S RECENT USE OF THE CAPM METHOD AS A FACTOR IN ESTABLISHING A RETURN ON EQUITY?

A. Yes. The Commission indicated in Aqua Pennsylvania, Inc.'s (Aqua) 2021 base rate case order that its method "for determining Aqua's ROE shall utilize both I&E's DCF and CAPM methodologies"[22] and that "I&E's DCF and CAPM produce a range of reasonableness for the ROE …",[23] which deviates from the historical Commission practice of primarily relying on the DCF. Additionally, the

[21] David C. Parcell, "The Cost of Capital – A Practitioner's Guide," 2020 Edition, pp. 167-168.
[22] *Pa. PUC v. Aqua Pennsylvania, Inc.,* Docket Nos. R-2021-3027385 & R-2021-3027386, p. 154 (Order Entered May 16, 2022).
[23] *Id.* at p. 178.

Commission's Columbia Water Company (Columbia Water) base rate case order relied on the results of I&E's DCF and CAPM analyses for determining Columbia Water's ROE.[24] Finally, in the most recent Pennsylvania-American Water Company case, the Commission agreed with the ALJ's recommended ROE which was based on the average of I&E's DCF and CAPM analyses.[25]

In a report issued by Regulatory Research Associates, a group within S&P Global Market Intelligence,[26] Aqua's return on equity of 10.00% is stated as being above the national average for water utility base rate cases and above the Distribution System Improvement Charge (DSIC) authorized by the Commission of 9.80%[27] for water and wastewater utilities based on a period ended March 31, 2022. The above referenced report also states that the average return on equity for water utility base rate cases that have been completed during the first four months of 2022 was 9.63% and for the twelve months ended April 30, 2022 was 9.53% which were well below the 10.00% return on equity authorized by the Commission for Aqua. Although this is related specifically to the water utility industry, it demonstrates the unreasonable skewing of results associated with using the CAPM as a ceiling for determining a utility's return on equity.

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[24] *Pa. PUC v. Columbia Water Company,* Docket No. R-2023-3040258, p. 105 (Order Entered January 18, 2024).

[25] *Pa. PUC v. Pennsylvania-American Water Company,* Docket Nos. R-2023-30433189 & R-2023-3043190, p. 194 (Order Entered July 22, 2024).

[26] Regulatory Research Associates, "Commission authorizes management performance bonus for Aqua Pennsylvania," *S&P Global Market Intelligence*, May 16, 2022. CIQ Pro: RRA Regulatory Focus: Commission authorizes management performance bonus for Aqua Pennsylvania (spglobal.com) (Accessed January 23, 2024).

[27] PA Public Utility Commission, Bureau of Technical Utility Services Report on the Quarterly Earnings of Jurisdictional Utilities for the Year Ended March 31, 2022, approved at Public Meeting on August 4, 2022 at Docket No. M-2022-3032561.

In the Columbia Water order, the Commission noted that I&E's DCF and CAPM produced a range of reasonableness for the ROE from 7.84% to 11.09% and approved an ROE of 9.75% as reasonable and appropriate for that company, which is based upon consideration of a variety of factors such as increasing inflation leading to increases in interest rates and capital costs.[28] I respectfully disagree with the Commission's basis (current inflation and interest rates) for determining Columbia Water's ROE of 9.75%. I have presented and discussed below the forecasted lower-level inflation rates, and the Federal Reserve's intention to cut interest rates in 2025-2026, which would have the effect of reducing potential inflation and interest rate risks on capital costs during 2026, when the Companies' new rates will be in effect.

Additionally, as explained above, the CAPM should not be used as a primary method, and it should only be used as a comparison (not as a check) of the DCF. Also, as demonstrated below, the use of the CAPM in this proceeding would result in a significant burden to ratepayers during a time of increased levels of inflation. Therefore, I disagree with providing the CAPM comparable weight to the DCF method.

[28] *Pa. PUC v. Columbia Water Company,* Docket No. R-2023-3040258, pp.108-109 (Order Entered January 18, 2024).

Q. PLEASE COMMENT ON CURRENT INFLATION AND INTEREST RATE CONCERNS.

A. First, while I cannot dispute the recent economic conditions with respect to increased interest rates and government bond yields, it is important to note that all companies, including regulated utilities, are impacted by high interest rates. It is my understanding that the Federal Reserve may consider resuming interest rate cuts later this year which would impact the Companies' FPFTY when the new rates will be in effect.[29]

With respect to inflation rates, per the most recent monthly Blue Chip Financial Forecasts,[30] the 2026 inflation rates by two measures are forecasted to be in the range of 2.3% to 2.8% as shown in the table below:

	Q2 2025	Q3 2025	Q4 2025	Q1 2026	Q2 2026	Q3 2026
Consumer Price Index	3.4%	3.7%	3.1%	2.8%	2.5%	2.4%
PCE Price Index	3.5%	3.4%	3.0%	2.6%	2.4%	2.3%

Potential future reductions in interest rates could have the effect of reducing debt cost rates in the capital costs in 2026, when the Companies' new rates will be in effect. Lastly, it is important to note that unlike unregulated companies, public utilities may file rate cases to address unforeseen or increased expenses, increases

[29] https://www.reuters.com/business/fed-keep-rates-hold-least-until-september-inflation-risks-linger-2025-06-10/, (accessed June 23, 2025).

[30] Blue Chip Financial Forecasts Vol. 44, No. 5, May 1, 2025.

in the costs of borrowing, and equity and/or revenue shortfalls due to changes in market conditions.

SUMMARY OF THE COMPANIES' RESULTS

Q. WHAT ARE THE RESULTS OF THE COMPANIES' COST OF EQUITY ANALYSES?

A. Mr. D'Ascendis used the DCF, CAPM, and the RP methods in analyzing the Companies' cost of equity. Mr. D'Ascendis also used the Predictive Risk Premium Method (PRPM) and the Empirical Capital Asset Pricing Model (ECAPM) in forming his recommendations under the RP and the CAPM methods, respectively. Mr. D'Ascendis applied these methods using his proxy group of regulated electric utilities and averaged the results of the methods for his non-price regulated proxy group. Mr. D'Ascendis then listed the results for each method for the regulated utility group and the average of the median and mean of the results of the methods for the non-price regulated group. Mr. D'Ascendis recommended that the cost of equity be increased by 85 basis points due to the Companies' small size. Finally, Mr. D'Ascendis recommended that the cost of equity also be increased by five basis points to reflect a performance factor adjustment. Ultimately, Mr. D'Ascendis opined that a cost of equity of 11.65% is warranted.[31]

[31] Citizens'/Wellsboro Statement No. 2, p. 4, line 14 through p. 6, line 8 and Exhibit (DWD-1), Schedule DWD-1.

I&E RECOMMENDATION

Q. WHAT IS YOUR RECOMMENDED COST OF COMMON EQUITY FOR THE COMPANIES?

A. Based upon my analysis, I recommend a cost of common equity of 10.78%.[32]

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATION?

A. My recommendation is based on the use of the DCF method. As explained above, I used my CAPM result only to present to the Commission a comparison and not as a check to my DCF results. My DCF analysis uses a spot dividend yield, a 52-week dividend yield, and earnings growth forecasts.

Discounted Cash Flow

Q. PLEASE EXPLAIN YOUR DCF ANALYSIS.

A. My analysis employs the constant growth DCF model as portrayed in the following formula:

$$K = D_1/P_0 + g$$

Where:

K	=	Cost of equity
D_1	=	Dividend expected during the year
P_0	=	Current price of the stock
g	=	Expected growth rate

[32] I&E Exhibit No. 2, Schedule 1.

When a forecast of D_1 is not available, D_0 (the current dividend) must be adjusted by one half of the expected growth rate to account for changes in the dividend paid in period one. As forecasts for each company in my proxy group were available from Value Line, no dividends were adjusted for the purpose of my analysis.

Q. PLEASE EXPLAIN HOW YOU DEVELOPED THE DIVIDEND YIELDS USED IN YOUR DCF ANALYSIS.

A. A representative dividend yield must be calculated over a time frame that avoids the problems of both short-term anomalies and stale data series. For my DCF analysis, the dividend yield calculation places equal emphasis on the most recent spot and the 52-week average dividend yields. The following table summarizes my dividend yield computations for the proxy group:[33]

Nine-Company Proxy Group	Dividend Yield
Spot	4.03%
52-week Average	4.05%
Average	4.04%

Q. WHAT INFORMATION DID YOU RELY UPON TO DETERMINE YOUR EXPECTED GROWTH RATE?

A. I have used five-year earnings per share projected growth rate estimates from S&P,

[33] I&E Exhibit No. 2, Schedule 6.

Zacks, and Value Line.

Q. WHAT WERE THE RESULTS OF YOUR FORECASTED EARNINGS GROWTH RATES?

A. The expected average growth rates for my proxy group ranged from 5.61% to 10.33% with an overall average of 6.92%. For the purpose of determining the growth estimate, I subsequently eliminated Dominion Energy's Zacks growth estimate of 13.60% to determine a new adjusted average of 6.74%.[34]

Q. WHY DID YOU ELIMINATE DOMINION ENERGY'S ZACKS PROJECTED GROWTH RATE?

A. While the use of a proxy group largely smooths out various anomalies, Zacks' growth projection for Dominion Energy is extremely inconsistent and would have an unreasonable and unwarranted impact on my DCF analysis. This would adversely affect my recommendation for the Companies' cost of common equity because it is harmful to ratepayers by creating an unjustified increase in return on equity and consequently pressures rates upward, which is not in the public interest. Zacks' estimate of 13.60% is almost double, and greater than three standard deviations over the originally calculated 6.92% overall average. Additionally, I was unable to find any explanation or justification of why this estimate was so high.

[34] I&E Exhibit No. 2, Schedule 7.

Q. WHAT IS THE RESULT OF YOUR DCF ANALYSIS BASED ON YOUR RECOMMENDED DIVIDEND YIELD AND GROWTH RATE?

A. The results of my DCF analysis is calculated as follows:[35]

K	=	D_1/P_0	+	g
10.78%	=	4.04%	+	6.74%

Capital Asset Pricing Model

Q. PLEASE EXPLAIN YOUR CAPM ANALYSIS.

A. My analysis employs the traditional CAPM as portrayed in the following formula:

$$K = R_f + \beta(R_m - R_f)$$

Where:

K	=	Cost of equity
R_f	=	Risk-free rate of return
R_m	=	Expected rate of return on the overall stock market
β	=	Beta measures the systematic risk of an asset
$R_m - R_f$	=	Equity Risk Premium (ERP)

Q. WHAT IS BETA AS EMPLOYED IN YOUR CAPM ANALYSIS?

A. Beta is a measure of the systematic risk of a stock in relation to the rest of the stock market. A stock's beta is estimated by calculating the linear regression of a

[35] I&E Exhibit No. 2, Schedule 8.

stock's return against the return on the overall stock market. The beta of a stock with a price pattern identical to that of the overall stock market will equal one. A stock with a price movement that is greater than the overall stock market will have a beta that is greater than one and would be described as having more investment risk than the market. Conversely, a stock with a price movement that is less than the overall stock market will have a beta of less than one and would be described as having less investment risk than the overall stock market.

Q. HOW DID YOU DETERMINE BETA FOR YOUR CAPM ANALYSIS?

A. In estimating an equity cost rate for my proxy group of nine electric companies, I used the average of the betas for the companies as provided in the Value Line Investment Survey. The average beta for my proxy group is 0.80.[36] It should be noted that Value Line did not have a beta for one of the companies in my proxy group, Exelon Corporation.

Q. WHAT RISK-FREE RATE OF RETURN HAVE YOU USED FOR YOUR FORECASTED CAPM ANALYSIS?

A. I used the risk-free rate of return (R_f) from the projected yield on 10-year Treasury Notes. While the yield on the short-term T-Bill is a more theoretically correct parameter to represent a risk-free rate of return, it can be extremely volatile. The volatility of short-term T-Bills is directly influenced by Federal Reserve policy. At

[36] I&E Exhibit No. 2, Schedule 9.

the other extreme, the 30-year Treasury Bond exhibits more stability but is not risk-free. Long-term Treasury Bonds have substantial maturity risk associated with market risk and the risk of unexpected inflation. Long-term treasuries normally offer higher yields to compensate investors for these risks. As a result, I used the yield on the 10-year Treasury Note because it mitigates the shortcomings of the other two alternatives. Additionally, the Commission has historically agreed with I&E and recognized the 10-year Treasury Note as the superior measure of the risk-free rate of return.[37]

The forecasted yield on the 10-year Treasury Note, as seen in Blue Chip Financial Forecasts, is trending downward from 4.20% in the third quarter of 2025 to 4.10% in the third quarter of 2026, and it is forecasted to be 4.00% from 2026-2030. For my CAPM analysis, I used 4.10%, which is the average of all the yield forecasts I observed.[38]

Q. HOW DID YOU DETERMINE THE RETURN ON THE OVERALL STOCK MARKET IN YOUR FORECASTED CAPM ANALYSIS?

A. To arrive at a representative expected return on the overall stock market, I observed Value Line's 1700 stocks and the historical returns of the S&P 500.

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[37] *Pa. PUC v. UGI Utilities, Inc. – Electric Division*, Docket No. R-2017-2640058 (Order Entered October 25, 2018). *See generally* Disposition of Capital Asset Pricing Model (CAPM), p. 99; *Pa. PUC v. Aqua Pennsylvania, Inc.*, Docket Nos. R-2021-3027385 & R-2021-3027386, p. 154 (Order Entered May 16, 2022); *Pa. PUC v. Columbia Water Company*, Docket No. R-2023-3040258 (Order Entered January 18, 2024). *See generally* Disposition of Cost of Common Equity, pp. 107-108; *Pa. PUC v. Pennsylvania-American Water Company*, Docket Nos. R-2023-3043189 & R-2023-3043190 (Order Entered July 22, 2024). *See generally* Disposition of Capital Asset Pricing Model (CAPM), pp. 171-172.

[38] I&E Exhibit No. 2, Schedule 10.

Value Line expects its universe of approximately 1700 stocks to have an average yearly return of 13.88% over the next three to five years based on a forecasted dividend yield of 2.30% and a yearly index appreciation of 55%. The S&P 500 Index has had an average return of 12.29% over the past 99 years (1926-2024).[39] I have averaged these two figures which results in an estimated market return of 13.09%.[40]

Q. WHAT IS THE COST OF EQUITY RESULT FROM YOUR CAPM ANALYSIS USING A FORECASTED OVERALL MARKET RETURN?

A. The result of my analysis is as follows:[41]

K	=	R_f	+	$\beta(R_m - R_f)$
11.29%	=	4.10%	+	0.80 (13.09% - 4.10%)

Q. HAVE YOU PROVIDED AN ADDITIONAL CAPM ANALYSIS?

A. Yes. I have provided an additional CAPM analysis using Kroll's (formerly Duff & Phelps) recommended U.S. Equity Risk Premium (ERP) paired with the 20-year U.S. Treasury yield. Kroll is a trusted and publicly available source that bases their recommended ERP on current and forecasted economic and financial market conditions.

[39] I&E Exhibit No. 2, Schedule 11.
[40] I&E Exhibit No. 2, Schedule 12.
[41] I&E Exhibit No. 2, Schedule 13.

Q. WHAT IS KROLL'S CURRENT RECOMMENDED ERP?

A. As of April 15, 2025, Kroll recommends an ERP of 5.50%.

Q. WHAT IS THE CURRENT 20-YEAR U.S. TREASURY YIELD?

A. As of May 14, 2025, the 20-Year U.S. Treasury yield was 4.95%.

Q. WHAT IS THE COST OF EQUITY RESULT FROM YOUR CAPM ANALYSIS USING KROLL'S RECOMMENDED ERP AND THE 20-YEAR U.S. TREASURY YIELD?

A. The result of my analysis is as follows:[42]

K	=	R_f	+	β(ERP)
9.35%	=	4.95%	+	0.80 (5.50%)

Q. WHAT IS THE RESULT OF YOUR CAPM ANALYSIS BASED ON THE AVERAGE OF USING A FORECASTED OVERALL MARKET RETURN AND USING KROLL'S RECOMMENDED ERP AND 20-YEAR TREASURY YIELD?

A. The average of my CAPM analyses is 10.32% ((11.29% + 9.35%) ÷ 2).[43]

[42] I&E Exhibit No. 2, Schedule 13.
[43] *Id.*

Q. DO YOU HAVE ANY ADDITIONAL COMMENTS REGARDING YOUR CAPM ANALYSIS?

A. Yes. As discussed earlier in my testimony, and as I&E has historically reasoned, my recommended cost of equity is based upon my DCF analysis. My CAPM analyses are only presented to the Commission as a comparison and not for recommendation purposes as the inputs are highly subjective, and other than beta, not company or industry specific.

Q. IS IT NECESSARY OR APPROPRIATE TO APPLY THE CAPM WITH SIMILAR WEIGHT TO THE DCF WHEN DETERMINING A SPECIFIC RETURN ON EQUITY DUE TO RECENT INFLATIONARY TRENDS?

A. No. My use of the DCF as a primary method in determining an appropriate return on equity already sufficiently takes inflationary trends into consideration. As mentioned above, the DCF includes a spot stock price in the dividend yield calculation and analysts who generate forecasted earnings growth almost certainly take inflation into consideration as well, so it contains the most up-to-date projected information of any model. In other words, the inputs of the DCF capture all known economic factors, including inflation.

CRITIQUE OF MR. D'ASCENDIS' PROPOSED COST OF EQUITY

Q. DO YOU AGREE WITH MR. D'ASCENDIS' 11.65% PROPOSED COST OF EQUITY?

A. No. I disagree with Mr. D'Ascendis' proposed cost of equity analysis for several reasons. First, I disagree with the weights given to the results of his DCF, CAPM, RP, PRPM, and ECAPM analyses in his recommendation. Second, I disagree with the use of a proxy group of companies he used in the Companies' cost of equity calculation that are not regulated electric utilities. Third, I disagree with his inclusion of a size adjustment and a performance factor adjustment. Finally, I disagree with his reliance on the 30-year Treasury Bond for his risk-free rate.

Weights Given to the CAPM and RP Methods

Q. DO YOU AGREE WITH MR. D'ASCENDIS' RELIANCE ON THE CAPM AND RP MODELS?

A. No. While I am not opposed to providing the Commission the results of the CAPM for a point of comparison to the results of the DCF calculation, I am opposed to giving the CAPM and RP considerable weight. For the reasons discussed above, it is not appropriate to give the CAPM and RP models similar weight to the DCF as Mr. D'Ascendis has done in creating his recommended cost of equity range.[44] As discussed above, the CAPM measures the cost of equity indirectly and can be manipulated by the time period chosen. Since the RP is a

[44] Citizens' Statement No. 2, p. 7, line 1.

simplified version of the CAPM, it suffers these same flaws. Also, as discussed in more detail below, the results of the lesser-used ECAPM and PRPM models should also be rejected. I have not used the ECAPM because it only weights the results of the CAPM in order to flatten the Security Market Line, but it does not correct the previously discussed problems with the CAPM. I have not used Mr. D'Ascendis' Predicative Risk Premium Model, because it is not a widely accepted method and investors must have a statistical software package to use the PRPM.

Predictive Risk Premium Model

Q. WHAT IS THE PREDICTIVE RISK PREMIUM MODEL?

A. The PRPM is a method published in August 2011 by Pauline M. Ahern, Frank J. Hanley, and Richard A. Michelfelder in the article *New Approach to Estimating the Cost of Common Equity Capital for Public Utilities.*[45] Mr. D'Ascendis' PRPM requires Eviews© statistical software to compute.[46]

Q. DO YOU AGREE WITH MR. D'ASCENDIS' USE OF THE PRPM?

A. No. Mr. D'Ascendis' PRPM is not a commonly used method and cannot be evaluated or recreated without the software. I am also unaware of any state that

[45] Ahern, Pauline M., Hanley, Frank J., Michelfelder, Richard A. (December 2011, Volume 40, Issue 3). *New Approach to Estimating the Cost of Common Equity Capital for Public Utilities*. Journal of Regulatory Economics, pp. 261-278.

[46] Citizens'/Wellsboro Statement No. 2, pp. 27-28.

has accepted the use of the PRPM. Finally, the PRPM does not solve the problem of the RP method because it is still an indirect measure of the cost of equity, and the PRPM complicates the RP method with the introduction of a measurement that requires the use of specialized software.

Empirical Capital Asset Pricing Model

Q. WHAT DOES MR. D'ASCENDIS CLAIM IS THE BASIS FOR HIS USE OF THE ECAPM?

A. Mr. D'Ascendis opines that the Security Market Line (SML) defined by the CAPM is not as steeply sloped as the predicted SML.[47] Mr. D'Ascendis used a formula to account for the systematic risk that is not accounted for with beta in the CAPM formula. This methodology, called ECAPM, uses a factor, alpha, to account for the additional systematic risk not captured by beta.

Q. DO YOU AGREE WITH MR. D'ASCENDIS' USE OF THE ECAPM?

A. No. The use of the ECAPM in estimating the cost of capital does not increase the validity of the result, but instead it injects another measure of subjectivity to the CAPM in an attempt to make the Security Market Line more accurate. The ECAPM reduces the purpose of the beta, which is the only company-specific variable in the CAPM model. This additional layer of subjectivity provides an even stronger basis to rely on the DCF, as I have done, as the primary method to

[47] Citizens'/Wellsboro Statement No. 2, p. 35, line 19 through p. 36, line 2.

calculate a utility's cost of equity. Additionally, I am not aware of any instances where a utility commission overseeing base rate proceedings explicitly relied on the ECAPM when determining an appropriate cost of equity for a regulated utility..

Risk-Free Rate

Q. WHAT RISK-FREE RATE DOES MR. D'ASCENDIS USE IN HIS RP AND CAPM MODELS?

A. Mr. D'Ascendis calculated his risk-free rate of 4.55% by using the 30-year Treasury Bonds.[48]

Q. DO YOU AGREE WITH MR. D'ASCENDIS' USE OF THE 30-YEAR TREASURY BOND TO DETERMINE THE RISK-FREE RATE?

A. No. As discussed above, long-term Treasury Bonds have substantial maturity risk associated with the market risk and the risk of unexpected inflation and normally offer higher yields to compensate investors for these risks. Using the 10-year Treasury Note is more appropriate to balance the short-term volatility risk and the long-term inflation risk. Further, as noted above the Commission has recognized the 10-year Treasury Note as the superior measure of the risk-free rate of return.

[48] Citizens'/Wellsboro Statement No. 2, p. 38, lines 7-13.

Domestic Non-Price Regulated Companies

Q. DOES MR. D'ASCENDIS RELY ON ANY MARKET DATA INPUTS SPECIFIC TO COMPANIES THAT ARE NOT REGULATED UTILITIES?

A. Yes. Mr. D'Ascendis asserted that in the *Hope* and *Bluefield* cases, the U.S. Supreme Court did not specify that comparable risk companies had to be utilities. Consequently, he assembled a proxy group consisting of 47 non-price regulated firms which he asserted are comparable in terms of total risk to the Electric Utility Proxy Group.[49] After forming his proxy group of 47 non-price regulated firms, Mr. D'Ascendis calculated common equity costs with data inputs specific to these companies using the DCF, RP, and CAPM methods.[50] The average of the mean and median results of these analyses of 11.84% was incorporated into Mr. D'Ascendis' final calculation of the Companies' return on equity of 11.65%.[51]

Q. DO YOU AGREE WITH MR. D'ASCENDIS' APPROACH OF USING THE MARKET DATA OF NON-UTILITY COMPANIES TO CALCULATE CITIZENS' RETURN ON EQUITY?

A. No. The process of choosing a proxy group of non-utility companies similar in risk to the Companies is highly speculative and subjective. In effect, Mr. D'Ascendis has blended the CE approach into the DCF, RP, and CAPM models.

[49] Citizens'/Wellsboro Statement No. 2, pp. 41-45.
[50] Citizens'/Wellsboro Exhibit (DWD-1), Schedule DWD-7.
[51] Citizens'/Wellsboro Exhibit (DWD-1), Schedule DWD-1.

As stated earlier, the Commission has ruled on the use of the CE approach, specifically, the use of non-utility companies in comparable groups, and stated:

> The use of nonregulated companies as a comparable group for regulated firms requires numerous unsupportable assumptions which results in a highly speculative finding.[52]

Additionally, in the 2018 UGI Utilities, Inc. – Electric Division base rate case, the Commission made the following comments regarding the CE method, specifically the use of non-utility companies in comparable groups, and stated:[53]

> With respect to the CE method, as noted above, this cost of equity method utilizes data for non-regulated firms. Thus, by its very nature, determining which companies are comparable is entirely subjective. In addition, the record indicates that the companies UGI utilized in its CE group results in the selection of companies such as Coca-Cola Company, Kellogg Company, and Walmart Stores, Inc. . . . Each of these companies operate in industries that are very different from a utility company and have significantly more competition, which would require a higher return for the associated additional risk.

If the non-price regulated company proxy group is truly similar in total risk to the Companies, I would expect to see similar results in the calculation of the DCF, RP, and CAPM between the Electric Utility and Non-Price Regulated Company proxy groups used by Mr. D'Ascendis. However, all three Non-Price Regulated Company proxy group results were higher. This clearly demonstrates the Commission's ruling that "[t]he use of nonregulated companies as a comparable group for regulated firms … results in a highly speculative finding."[54]

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[52] *Pennsylvania Public Utility Commission v. Philadelphia Electric Co.*, 33 PUR 4th 319, 341 (Pa. PUC 1980).

[53] *Pa. PUC v. UGI Utilities, Inc. – Electric Division*, Docket No. R-2017-2640058, p. 105 (Order Entered October 25, 2018).

[54] *Pennsylvania Public Utility Commission v. Philadelphia Electric Co.*, 33 PUR 4th 319, 341 (Pa. PUC 1980).

Size Adjustment

Q. WHAT SIZE ADJUSTMENT HAS MR. D'ASCENDIS PROPOSED?

A. Mr. D'Ascendis added 85 basis points to his cost of common equity because he opined that smaller companies are less able to cope with significant events affecting sales, revenues, or earnings. He further stated that the loss of revenue from a few larger customers would have a greater effect on a small company. Mr. D'Ascendis relied upon technical literature including Kroll's Cost of Capital Navigator – U.S. Guide to Cost of Capital, "Size as a Predictor of Equity Returns," a Fama and French study entitled "The Capital Asset Pricing Model: Theory & Evidence," and Professor Eugene Brigham's textbook entitled "Fundamentals of Finance Management." Mr. D'Ascendis quantified his size adjustment based on size premiums for portfolios of New York Stock Exchange, American Stock Exchange, and NASDAQ listed companies ranked by deciles for the 1926 to 2024 period. While Mr. D'Ascendis' proxy group companies fell in the 3rd decile, he asserted that the Companies fell in the 10th decile for size. He stated that while this indicates an upward equity risk premium adjustment of 398 basis points, he chose an upward adjustment of 85 basis points. Finally, Mr. D'Ascendis points to a 2019 Commission order where the Commission considered a size adjustment.[55]

Q. DO YOU AGREE WITH MR. D'ASCENDIS' SIZE ADJUSTMENT?

A. No. Mr. D'Ascendis' proposed size adjustment is unnecessary because the

[55] Citizens'/Wellsboro Statement No. 2, pp. 47-51.

technical literature he cited supporting investment adjustments related to the size of a company is not specific to the utility industry; therefore, it has no relevance in this proceeding. Furthermore, any expense impact resulting from the lesser buying power of a smaller utility is reflected in the revenue requirement and the dollar-for-dollar recovery that applies to expenses. To apply an additional size adjustment to a smaller regulated utility would only duplicate the burden to ratepayers.

Q. IS THERE ACADEMIC EVIDENCE THAT SUPPORTS YOUR CONCLUSION THAT THE SIZE ADJUSTMENT FOR RISK IS NOT APPLICABLE TO UTILITY COMPANIES?

A. Yes. In the article "Utility Stocks and the Size Effect: An Empirical Analysis," Dr. Annie Wong concludes:

> The objective of this study is to examine if the size effect exists in the utility industry. After controlling for equity values, there is some weak evidence that firm size is a missing factor from the CAPM for the industrial but not for utility stocks. This implies that although the size phenomenon has been strongly documented for the industriales, the findings suggest that there is no need to adjust for the firm size in utility rate regulation.[56]

The Companies have presented no evidence to support application of a non-utility study regarding a size adjustment for risk to a utility setting. Absent any credible article to refute Dr. Wong's findings, Mr. D'Ascendis' size adjustment to his cost

[56] Dr. Annie Wong, "Utility Stocks and the Size Effect: An Empirical Analysis," *Journal of Midwest Finance Association* 1993, pp. 95-101.

of common equity results should be rejected. Furthermore, the Commission has rejected the application of a size adjustment to the cost of equity calculation.[57]

Q. DID THE COMMISSION AWARD A SIZE ADJUSTMENT IN THE REFERENCED COMMISSION ORDER FOR CITIZENS'?

A. No. The Commission did not, in fact, award an explicit 100-basis point size adjustment that was recommended by Citizens' as the Commission determined that there was not enough evidence as to whether size is specifically a risk for utilities:

> Consistent with the foregoing discussion, like the ALJs, we shall not specify an exact size adjustment. Instead, we shall adopt the ALJs' recommendation that Citizens' be awarded a DCF cost of common equity of 9.49%. In our view, this cost of equity is reasonable and strikes an appropriate balance by recognizing the general inverse relationship between a company's size and its risk, while acknowledging that there is not substantial evidence in the record to prove that an explicit size basis point adjustment is warranted in this case.[58]

Q. BASED ON THE COMPANIES' FILED RATE BASE AND CLAIMED CAPITAL STRUCTURES, WHAT IS THE VALUE OF AN ADDITIONAL 85 BASIS POINTS TO THE COST OF EQUITY?

A. The example below illustrates the impact of 85 additional basis points to the Companies' cost of equity:

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[57] *Pa. PUC v. UGI Utilities, Inc. – Electric Division*, Docket No. R-2017-2640058 (Order Entered October 25, 2018). *See generally* Disposition of Capital Asset Pricing Model (CAPM), p. 100.

[58] *Pa. PUC v. Citizens Electric Company of Lewisburg, PA;* Docket No. R-2019-3008212 (Order Entered April 27, 2020). *See generally* Disposition of Cost of Common Equity, pp. 103-104.

Citizens' Electric Company of Lewisburg, PA	
Claimed Equity Percentage of Capital Structure	51.06%
Additional Basis Points to Calculated Cost of Equity	85
Claimed Rate Base[59]	$17,092,345
Impact Prior to Gross Revenue Conversion Factor (0.5106 x 0.0085 x $17,092,345)	**$74,182**
Gross Revenue Conversation Factor[60]	1.494488
Total Impact (1.494488 x $74,182)	**$110,864**

Wellsboro Electric Company	
Claimed Equity Percentage of Capital Structure	51.06%
Additional Basis Points to Calculated Cost of Equity	85
Claimed Rate Base[61]	$25,857,280
Impact Prior to Gross Revenue Conversion Factor (0.5106 x 0.0085 x $25,857,280)	**$112,223**
Gross Revenue Conversation Factor[62]	1.49449
Total Impact (1.49449 x $112,223)	**$167,716**

[59] Citizens' Exhibit (HSG-1), Schedule C1-5.
[60] I&E Exhibit No. 2, Schedule 14.
[61] Wellsboro Exhibit (HSG-1), Schedule C1-5.
[62] I&E Exhibit No. 2, Schedule 15.

In this example, an addition of 85 basis points to the cost of equity would force ratepayers to fund an unwarranted additional amount of $110,864 and $167,716 for Citizens' and Wellsboro, respectively.

Performance Factor Adjustment

Q. WHAT IS THE COMPANIES' CLAIM REGARDING A PERFORMANCE FACTOR ADJUSTMENT?

A. Mr. D'Ascendis explains that his 11.65% cost of equity recommendation includes five basis points in consideration of the Companies' exemplary management performance. Mr. D'Ascendis points to Citizens' 2019 base rate case[63] and Valley Energy, Inc.'s, the Companies' affiliate, 2019 base rate case[64] where the Commission considered a management performance adjustment. Mr. D'Ascendis primarily relied upon the direct testimony of Citizens' witness Nathan Johnson[65] and Wellsboro witness Byron Farnsworth, Jr.[66] to support the consideration of additional basis points for the Companies' management performance.[67]

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63 *Pa. PUC v. Citizens Electric Company of Lewisburg, PA*, Docket No. R-2019-3008212 (Order Entered April 27, 2020). *See generally* Disposition of Return on Equity: Management Effectiveness Adjustment, pp. 108-110.

64 *Pa. PUC v. Valley Energy, Inc.*, Docket No. R-2019-3008212 (Order Entered April 27, 2020). *See generally* Disposition of Return on Equity: Management Effectiveness Adjustment, pp. 118-120.

65 Citizens' Statement No. 4.

66 Wellsboro Statement No. 4.

67 Citizens'/Wellsboro Statement No. 2, p. 51, line 21 through p. 52, line 9.

Q. WHAT INFORMATION DO MR. JOHNSON AND MR. FARNSWORTH PROVIDE TO SUPPORT THE COMPANIES' MANAGEMENT PERFORMANCE CLAIMS?

A. Mr. Johnson claims that Citizens' exemplary management performance is demonstrated through among other things, low customer complaints, favorable customer feedback, high responsiveness to customer support calls and energizing new service locations, excellent reliability metrics, zero reportable injuries, technology adoption of SmartHub use and tablets for line crews, increased pole attachment billing, "Tree Line USA" designation, and significant capital investments.[68]

Mr. Farnsworth claims that Wellsboro's exemplary management performance is demonstrated through among other things, excellent reliability metrics, low customer complaints, favorable customer feedback, high responsiveness to customer support calls, significant capital investments, technology adoption of SmartHub use, very low reportable injuries, and street light upgrades.[69]

[68] Citizens' Statement No. 4, p. 9, line 20 through p. 12, line 11.
[69] Wellsboro Statement No. 4, p. 8, line 1 through p. 10, line 5.

Q. ARE YOU AWARE OF ANY COMPANIES THAT HAVE RECENTLY RECEIVED ADDITIONAL BASIS POINTS IN RECOGNITION OF MANAGEMENT PERFORMANCE?

A. Yes. The Commission recently awarded Aqua Pennsylvania, Inc. (Aqua) an addition of 25 basis points for its management performance efforts.[70] However, it is important to recognize that this addition was based specifically on Aqua rescuing troubled water and wastewater systems at the Commission's request. The Commission stated: [71]

> We specifically recognize Aqua's efforts and willingness to quickly provide emergency aid to various water and wastewater systems that needed substantial improvement. Aqua has often provided this emergency aid on short notice and at the request of the Commission or other parties to protect the public from egregious health and safety threats and to protect the Commonwealth's drinking water resources from catastrophic damage.

Q. DOES THE COMMISSION'S PAST ISSUANCE OF ADDITIONAL EQUITY POINTS TO RECOGNIZE MANAGEMENT PERFORMANCE MEAN THAT THE COMPANIES SHOULD ALSO RECEIVE AN ADJUSTED RETURN ON EQUITY IN THIS PROCEEDING?

A. No. The issuance of equity points to recognize management performance should be analyzed on a case-by-case basis. The situation in the Aqua proceeding as discussed above was very specific to Aqua acquiring troubled water and

[70] *Pa. PUC v. Aqua Pennsylvania, Inc.,* Docket Nos. R-2021-3027385 & R-2021-3027386, pp. 168-173 (Order Entered May 16, 2022).
[71] *Id.*

wastewater systems and preventing health and safety concerns regarding drinking water. This scenario does not apply to the Companies in this base rate case.

Q. BASED ON THE COMPANIES' FILED RATE BASE AND CLAIMED CAPITAL STRUCTURES, WHAT IS THE VALUE OF AN ADDITIONAL 5 BASIS POINTS TO THE COST OF EQUITY?

A. The example below illustrates the impact of 5 additional basis points to the Companies' cost of equity:

Citizens' Electric Company of Lewisburg, PA	
Claimed Equity Percentage of Capital Structure	51.06%
Additional Basis Points to Calculated Cost of Equity	5
Claimed Rate Base[72]	$17,092,345
Impact Prior to Gross Revenue Conversion Factor (0.5106 x 0.0005 x $17,092,345)	**$4,364**
Gross Revenue Conversation Factor[73]	1.494488
Total Impact (1.494488 x $4,364)	**$6,522**

[72] Citizens' Exhibit (HSG-1), Schedule C1-5.
[73] I&E Exhibit No. 2, Schedule 14.

Wellsboro Electric Company	
Claimed Equity Percentage of Capital Structure	51.06%
Additional Basis Points to Calculated Cost of Equity	5
Claimed Rate Base[74]	$25,857,280
Impact Prior to Gross Revenue Conversion Factor (0.5106 x 0.0005 x $25,857,280)	**$6,601**
Gross Revenue Conversation Factor[75]	1.49449
Total Impact (1.49449 x $6,601)	**$9,865**

In this example, an addition of 5 basis points to the cost of equity would force ratepayers to fund an unwarranted additional amount of $6,522 and $9,865 for Citizens' and Wellsboro, respectively.

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE CONSIDERATION OF THE COMPANIES' MANAGEMENT PERFORMANCE IN DETERMINING THE COMPANIES' RETURN ON EQUITY?

A. I am aware that under 66 Pa. C.S. § 523 the Commission has authority to *consider* a utility's performance, however, it is not mandatory that the Commission grant additional basis points to the ROE.[76] Ultimately, true strong management

[74] Wellsboro Exhibit (HSG-1), Schedule C1-5.
[75] I&E Exhibit No. 2, Schedule 15.
[76] 66 Pa. C.S. § 523(a).

performance is earning a higher return through efficient use of resources and cost cutting measures. The greater net income resulting from cost savings and true efficiency in management and operations is available to be passed on to both ratepayers and shareholders. I do not believe that the Companies, or any utility, should be gifted additional basis points for doing what they are required to do to provide adequate, efficient, safe, and reasonable service.[77] For these reasons, I recommend that any addition of basis points to the cost of equity for management performance be disallowed.

OVERALL RATE OF RETURN RECOMMENDATION

Q. WHAT IS THE COMPANIES' PROPOSED COST OF EQUITY AND OVERALL RATE OF RETURN?

A. The Companies recommend a cost of equity of 11.65% and an overall rate of return of 8.49% and 8.18% for Citizens' and Wellsboro, respectively.[78]

Q. WHAT IS I&E'S RECOMMENDED COST OF EQUITY AND OVERALL RATE OF RETURN?

A. I&E Exhibit No. 2, Schedule 1, shows the calculation of an appropriate cost of equity to be 10.78% for the Companies with an overall rate of return for Citizens' and Wellsboro to be 8.07% and 7.76%, respectively.

[77] *See* 66 Pa. C.S. § 1501.
[78] Citizens'/Wellsboro Statement No. 2, p. 3, lines 12-15.

Q. DO YOU HAVE ANY FINAL COMMENTS REGARDING THE COMPANIES' PROPOSED RETURN ON EQUITY?

A. Yes. First, a report issued by Regulatory Research Associates, a group within S&P Global Market Intelligence, shows that the average return on equity authorized for electric utilities was 9.74% for cases decided in 2024, which was based on 55 rate cases across the nation and 9.72% for cases decided in the first quarter of 2025.[79] The Companies request is 191 basis points above the average for 2024.

Second, when asked, Mr. D'Ascendis indicated he was unaware if any electric utilities throughout the United States were granted a commission-authorized return of 11.65% or higher cost of common equity in the past two years.[80]

Third, a very recent paper from the American Economic Liberties Project[81] written in January 2025 expresses many good points explaining how and why the returns on equity for investor-owned utilities are irrationally high. A few of the points this paper argues is that (1) over the past decade, utilities have been awarded ROEs that are roughly double what is "just and reasonable," (2) although regulated utilities enjoy lower risk than the market as a whole, authorized ROEs are notably higher that what is projected for the overall market, and (3) the author challenges the usefulness of the RP and CE methods used in calculating ROEs and

[79] Regulatory Research Associates, "Major energy rate case decisions in the US – January-March 2025, Quarterly update on decided rate cases," *S&P Global Market Intelligence*, April 25, 2025.
[80] I&E Exhibit No. 2, Schedule 16.
[81] Mark Ellis, "Rate of Return Equals Cost of Capital: A Simple, Fair Formula to Stop Investor-Owned Utilities From Overcharging the Public," *American Economic Liberties Project,* January 2025.

notes that in 2022, the Federal Energy Regulatory Commission began to prohibit the use of these models.

Finally, I believe it is important to consider the impact of what the Companies' excessive return on equity requests of 11.65% would have on rates. As illustrated in the various charts above, any additional basis points beyond the I&E recommended ROE of 10.78% based on a DCF (market-determined) result are unnecessary and will put an enormous burden on ratepayers. The impact to ratepayers of each of the disputed adjustments is summarized as follows:

Citizens' Electric Company of Lewisburg, PA	
Adjustment	**Total Impact**
Size Adjustment to CAPM	$110,864
Performance Adjustment Factor	$6,522

Wellsboro Electric Company	
Adjustment	**Total Impact**
Size Adjustment to CAPM	$167,716
Performance Adjustment Factor	$9,865

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

Professional and Educational Experience
Christopher Keller

Professional Experience

January 2014 to Present
Fixed Utility Financial Analyst
Pennsylvania Public Utility Commission, Harrisburg, Pennsylvania
Bureau of Investigation & Enforcement

September 2008 to January 2014
Insurance Company Financial Analyst
Pennsylvania Insurance Department, Harrisburg, Pennsylvania
Bureau of Licensing & Financial Analysis

Education and Training

FAI Utility Finance and Accounting for Financial Professionals, Boston, MA
May 21-23, 2014

York College of Pennsylvania, York, Pennsylvania
Master of Business Administration, Finance Concentration, 2008
Bachelor of Science, Accounting, 2006

Testimony Submitted

I have testified and/or submitted testimony in the following proceedings:

- Docket No. R-2025-3054938 – UGI Utilities, Inc. – Gas Division (1307(f))
- Docket No. R-2024-3052716 – UGI Utilities, Inc. – Gas Division (O&M)
- Docket No. R-2024-3052357 – Pike County Light & Power Company (Gas) (ROR)
- Docket No. A-2022-3033138 – Aqua Pennsylvania Wastewater, Inc. – Acquisition of the Wastewater System Assets of the City of Beaver Falls (1329)
- Docket No. P-2024-3051313 – Rock Spring Water Company (529 Investigation)
- Docket No. R-2024-3047822 – Aqua Pennsylvania, Inc. (ROR)
- Docket No. R-2024-3047824 – Aqua Pennsylvania Wastewater, Inc. (ROR)
- Docket No. M-2023-3042180 - Venango Water Company, Sugarcreek Water Company, West Hickory Water Company, Plumer Water Company, Fryburg Water Company, Cooperstown Water Company, and Blaine E. Rhodes Sewer Company (529 Investigation)
- Docket No. R-2024-3048828– UGI Utilities, Inc. – Gas Division (1307(f))
- Docket No. R-2024-3046932 – PECO Energy Company – Gas Division (O&M)
- Docket No. R-2024-3046523 – Duquesne Light Company (ROR)
- Docket No. R-2023-3044549 – Peoples Natural Gas Company LLC (O&M)
- Docket No. R-2023-3040258 – Columbia Water Company (O&M and ROR)
- Docket No. R-2023-3040290 – UGI Utilities, Inc. – Gas Division (1307(f))

Professional and Educational Experience
Christopher Keller

Testimony Submitted (Continued)

I have testified and/or submitted testimony in the following proceedings:

- Docket No. R-2022-3037368 – UGI Utilities, Inc. – Electric Division (O&M)
- Docket No. R-2022-3035730 – National Fuel Gas Distribution Corporation (O&M)
- Docket No. R-2022-3031340 – York Water Company – Water (ROR)
- Docket No. R-2022-3032806 – York Water Company – Wastewater (ROR)
- Docket No. R-2022-3032300 – Valley Energy, Inc. (ROR)
- Docket No. R-2022-3031704 – Borough of Ambler – Water Department (ROR)
- Docket No. R-2022-3032242 – UGI Utilities, Inc. – Gas Division (1307(f))
- Docket No. R-2022-3031211 – Columbia Gas of Pennsylvania, Inc. (ROR)
- Docket No. A-2021-3026132 – Aqua Pennsylvania Wastewater, Inc. – Acquisition of the Wastewater Collection and Conveyance System Assets of East Whiteland Township (1329)
- Docket No. P-2021-3030012 – Metropolitan Edison Company (DSP)
- Docket No. P-2021-3030013 – Pennsylvania Electric Company (DSP)
- Docket No. P-2021-3030014 – Pennsylvania Power Company (DSP)
- Docket No. R-2024-3046932 – PECO Energy Company – Gas Division (ROR)
- Docket No. P-2021-3030021 – West Penn Power Company (DSP)
- Docket No. R-2021-3026116 – Borough of Hanover – Water (ROR)
- Docket No. R-2021-3025206 – Community Utilities of Pennsylvania – Water Division (ROR)
- Docket No. R-2021-3025207 – Community Utilities of Pennsylvania – Wastewater Division (ROR)
- Docket No. R-2021-3025652 – UGI Utilities, Inc. – Gas Division (1307(f))
- Docket No. R-2021-3024750 – Duquesne Light Company (O&M and ROR)
- Docket No. R-2021-3024296 – Columbia Gas of Pennsylvania, Inc. (ROR)
- Docket No. R-2020-3018929 – PECO Energy Company – Gas Division (ROR)
- Docket No. P-2020-3020914 – Twin Lakes Utilities, Inc. (529 Proceeding)
- Docket No. R-2020-3018835 – Columbia Gas of Pennsylvania, Inc. (ROR)
- Docket No. R-2020-3019680 – UGI Utilities, Inc. (1307(f))
- Docket No. P-2020-3019356 – PPL Electric Utilities Corporation (DSP)
- Docket No. R-2019-3015162 – UGI Utilities, Inc. – Gas Division (ROR)
- Docket No. R-2019-3010955 – City of Lancaster – Sewer Fund (O&M)
- Docket No. R-2019-3009647 – UGI Utilities, Inc. – Gas Division (1307(f))
- Docket No. R-2018-3006818 – Peoples Natural Gas Company LLC (O&M)
- Docket No. R-2018-3000124 – Duquesne Light Company (O&M)
- Docket No. R-2018-3001631 – UGI Central Penn Gas, Inc. (1307(f))
- Docket No. R-2018-3001632 – UGI Penn Natural Gas, Inc. (1307(f))
- Docket No. R-2018-3001633 – UGI Utilities, Inc. (1307(f))
- Docket No. R-2018-2645938 – Philadelphia Gas Works (1307(f))

Professional and Educational Experience
Christopher Keller

Testimony Submitted (Continued)

I have testified and/or submitted testimony in the following proceedings:

- Docket No. P-2017-2637855 – Metropolitan Edison Company (DSP)
- Docket No. P-2017-2637857 – Pennsylvania Electric Company (DSP)
- Docket No. P-2017-2637858 – Pennsylvania Power Company (DSP)
- Docket No. P-2017-2637866 – West Penn Power Company (DSP)
- Docket No. R-2017-2602627 – UGI Central Penn Gas, Inc. (1307(f))
- Docket No. R-2017-2602638 – UGI Utilities, Inc. (1307(f))
- Docket No. R-2017-2586783 – Philadelphia Gas Works (O&M)
- Docket No. R-2017-2587526 – Philadelphia Gas Works (1307(f))
- Docket No. I-2016-2526085 – Delaware Sewer Company (529 Proceeding)
- Docket No. R-2016-2531550 – Citizens' Electric Company (O&M)
- Docket No. R-2016-2531551 – Wellsboro Electric Company (O&M)
- Docket No. R-2016-2537349 – Metropolitan Edison Company (CWC and CAP)
- Docket No. R-2016-2537352 – Pennsylvania Electric Company (CWC and CAP)
- Docket No. R-2016-2537355 – Pennsylvania Power Company (CWC and CAP)
- Docket No. R-2016-2537359 – West Penn Power Company (CWC and CAP)
- Docket No. R-2016-2543311 – UGI Central Penn Gas, Inc. (1307(f))
- Docket No. R-2015-2518438 – UGI Utilities, Inc. – Gas Division (CWC and USP)
- Docket No. P-2015-2511333 – Metropolitan Edison Company (DSP)
- Docket No. P-2015-2511351 – Pennsylvania Electric Company (DSP)
- Docket No. P-2015-2511355 – Pennsylvania Power Company (DSP)
- Docket No. P-2015-2511356 – West Penn Power Company (DSP)
- Docket No. R-2015-2468056 – Columbia Gas of Pennsylvania, Inc. (O&M)
- Docket No. P-2014-2404341 – Delaware Sewer Company (529 Investigation)
- Docket No. R-2014-2452705 – Delaware Sewer Company (O&M)
- Docket No. R-2014-2428304 – Borough of Hanover – Water (O&M)
- Docket No. R-2014-2419774 – Wellsboro Electric Company (Customer Choice Support Charge)
- Docket No. R-2014-2420279 – UGI Central Penn Gas, Inc. (1307(f))

Assisted with the Following Cases

- Docket No. R-2017-2631441 – Reynolds Water Company (ROR)
- Docket No. R-2016-2580030 – UGI Penn Natural Gas, Inc. (ROR)
- Docket No. R-2014-2462723 – United Water Pennsylvania (CWC)
- Docket No. R-2014-2428742 – West Penn Power Company (CWC)
- Docket No. R-2014-2428743 – Pennsylvania Electric Company (CWC)
- Docket No. R-2014-2428744 – Pennsylvania Power Company (CWC)
- Docket No. R-2014-2428745 – Metropolitan Edison Company (CWC)
- Docket No. R-2013-2397353 – Pike County Light & Power Company (Gas) (O&M)

Assisted with the Following Cases (Continued)

- Docket No. R-2013-2397237 – Pike County Light & Power Company (Electric) (O&M)

I&E Exhibit No. 2
Witness: Christopher Keller

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

WELLSBORO ELECTRIC COMPANY
Docket No. R-2025-3054392

&

CITIZENS' ELECTRIC COMPANY OF LEWISBURG, PA
Docket No. R-2025-3054394

Exhibit to Accompany

the

Direct Testimony

of

Christopher Keller

Bureau of Investigation and Enforcement

Concerning:

Rate of Return

I&E
Summary of Cost of Capital

Type of Capital	Ratio	Cost Rate	Weighted Cost
Citizens' Electric Company of Lewisburg			
Long-Term Debt	51.06%	5.47%	2.79%
Common Equity	48.94%	10.78%	5.28%
Total	100.00%		8.07%

I&E
Summary of Cost of Capital

Type of Capital	Ratio	Cost Rate	Weighted Cost
Wellsboro Electric Company			
Long-Term Debt	51.06%	4.85%	2.48%
Common Equity	48.94%	10.78%	5.28%
Total	100.00%		7.76%

Proxy Group Capital Structure

	2024		2023		2022		2021		2020		Average
Dominion Energy Inc.											
Long-term Debt	$ 38,169.000	58.34%	$ 33,858.000	55.16%	$ 39,428.000	58.58%	$ 37,890.000	56.71%	$ 34,473.000	56.90%	57.14%
Preferred Stock	991.000	1.51%	1,783.000	2.90%	1,783.000	2.65%	3,393.000	5.08%	2,387.000	3.94%	3.22%
Common Equity	26,262.000	40.14%	25,746.000	41.94%	26,098.000	38.77%	25,525.000	38.21%	23,730.000	39.16%	39.65%
	65,422.000	100.00%	61,387.000	100.00%	67,309.000	100.00%	66,808.000	100.00%	60,590.000	100.00%	100.00%
Duke Energy Corporation											
Long-term Debt	77,297.000	60.66%	73,369.000	59.90%	67,937.000	57.94%	61,522.000	55.52%	56,965.000	54.29%	57.66%
Preferred Stock	973.000	0.76%	1,962.000	1.60%	1,962.000	1.67%	1,962.000	1.77%	1,962.000	1.87%	1.54%
Common Equity	49,154.000	38.58%	47,150.000	38.50%	47,360.000	40.39%	47,334.000	42.71%	46,002.000	43.84%	40.80%
	127,424.000	100.00%	122,481.000	100.00%	117,259.000	100.00%	110,818.000	100.00%	104,929.000	100.00%	100.00%
Consolidated Edison Inc.											
Long-term Debt	25,040.000	53.27%	22,357.000	51.38%	20,625.000	49.92%	23,323.000	53.79%	21,148.000	52.88%	52.25%
Preferred Stock	-	0.00%	-	0.00%	-	0.00%	-	0.00%	-	0.00%	0.00%
Common Equity	21,962.000	46.73%	21,158.000	48.62%	20,687.000	50.08%	20,037.000	46.21%	18,847.000	47.12%	47.75%
	47,002.000	100.00%	43,515.000	100.00%	41,312.000	100.00%	43,360.000	100.00%	39,995.000	100.00%	100.00%
Eversource Energy											
Long-term Debt	26,133.499	63.47%	24,067.198	62.94%	20,236.586	56.67%	17,569.879	54.62%	15,726.088	52.79%	58.10%
Preferred Stock	-	0.00%	-	0.00%	-	0.00%	-	0.00%	-	0.00%	0.00%
Common Equity	15,039.387	36.53%	14,173.892	37.06%	15,473.158	43.33%	14,599.844	45.38%	14,063.566	47.21%	41.90%
	41,172.886	100.00%	38,241.090	100.00%	35,709.744	100.00%	32,169.723	100.00%	29,789.654	100.00%	100.00%
Exelon Corporation											
Long-term Debt	43,554.000	61.80%	40,330.000	61.03%	35,928.000	59.22%	36,682.000	51.61%	36,572.000	52.88%	57.31%
Preferred Stock	-	0.00%	-	0.00%	-	0.00%	-	0.00%	-	0.00%	0.00%
Common Equity	26,921.000	38.20%	25,755.000	38.97%	24,744.000	40.78%	34,393.000	48.39%	32,585.000	47.12%	42.69%
	70,475.000	100.00%	66,085.000	100.00%	60,672.000	100.00%	71,075.000	100.00%	69,157.000	100.00%	100.00%
FirstEnergy Corp											
Long-term Debt	22,688.000	64.56%	23,064.000	68.85%	21,450.000	67.85%	22,519.000	72.19%	22,394.000	75.58%	69.80%
Preferred Stock	-	0.00%	-	0.00%	-	0.00%	-	0.00%	-	0.00%	0.00%
Common Equity	12,455.000	35.44%	10,437.000	31.15%	10,166.000	32.15%	8,675.000	27.81%	7,237.000	24.42%	30.20%
	35,143.000	100.00%	33,501.000	100.00%	31,616.000	100.00%	31,194.000	100.00%	29,631.000	100.00%	100.00%
NextEra Energy Inc											
Long-term Debt	72,385.000	59.10%	61,405.000	56.40%	55,256.000	58.48%	50,960.000	57.80%	41,944.000	53.46%	57.05%
Preferred Stock	-	0.00%	-	0.00%	-	0.00%	-	0.00%	-	0.00%	0.00%
Common Equity	50,101.000	40.90%	47,468.000	43.60%	39,229.000	41.52%	37,202.000	42.20%	36,513.000	46.54%	42.95%
	122,486.000	100.00%	108,873.000	100.00%	94,485.000	100.00%	88,162.000	100.00%	78,457.000	100.00%	100.00%
Public Service Enterprise Group Inc.											
Long-term Debt	19,117.000	54.26%	17,957.000	53.71%	16,664.000	54.83%	15,410.000	51.63%	14,748.000	47.99%	52.48%
Preferred Stock	-	0.00%	-	0.00%	-	0.00%	-	0.00%	-	0.00%	0.00%
Common Equity	16,114.000	45.74%	15,477.000	46.29%	13,729.000	45.17%	14,438.000	48.37%	15,984.000	52.01%	47.52%
	35,231.000	100.00%	33,434.000	100.00%	30,393.000	100.00%	29,848.000	100.00%	30,732.000	100.00%	100.00%
PPL Corporation											
Long-term Debt	15,952.000	53.12%	14,680.000	51.31%	12,931.000	48.17%	10,713.000	43.84%	21,623.000	61.79%	51.64%
Preferred Stock	-	0.00%	-	0.00%	-	0.00%	-	0.00%	-	0.00%	0.00%
Common Equity	14,077.000	46.88%	13,933.000	48.69%	13,915.000	51.83%	13,723.000	56.16%	13,373.000	38.21%	48.36%
	30,029.000	100.00%	28,613.000	100.00%	26,846.000	100.00%	24,436.000	100.00%	34,996.000	100.00%	100.00%

Five-Year Average Capital Structure					
Long-term Debt	56.92%	Maximum	69.80%	Minimum	51.64%
Preferred Stock	0.59%				
Common Equity	42.49%	Minimum	30.20%	Maximum	48.36%
	100.00%				

Source:
Compustat (S&P Global Market Intelligence - Data Management Solutions)
Yearly data updates typically provided late April of each year
(data in millions)

Accessed on May 14, 2025

I&E-RR-5-D

Reference Citizens' Statement No. 2, p. 17, line 6 through p. 18, line 8. Identify each company from Value Line's Electric Utility East, Central, and West groups that were excluded from Mr. D'Ascendis and Mr. Kucan's Electric Utility Proxy Group. Specifically, state which of Mr. D'Ascendis and Mr. Kucan's criteria each company violated in order to be excluded.

Response Provided By:
Dylan W. D'Ascendis, Partner, ScottMadden, Inc.
Ryan M. Kucan, Manager, ScottMadden, Inc.

Date: May 30, 2025

Response:

Please refer to I&E-RR-5-D Attachment A.

I&E-RR-5-D Attachment A

Source: S&P Global Market Intelligence; SEC Company 10-Ks (as of February 28, 2025)
Numbers in ($000)

	NOI	NOI Regulated Electric	% Regulated Electric	Assets	Assets Regulated Electric	% Regulated Electric	NOI and Asset Sources	Both NOI and Assets >= 70% Regulated Electric	Merger / Significant Event?	Dividend Cutter?	VL / BB betas?	Positive VL DPS Growth Projections?	VL, Zacks, or Yahoo Proj EPS Growth Rates?	Proxy Group Company?
AEE	1,723,000	1,477,991	85.78%	47,179,000	38,202,000	80.97%	2023 10-K PDF 144, 145	Y	N	N	Y	Y	Y	Y
AEP	4,214,000	3,830,000	90.89%	101,008,600	93,216,100	92.29%	2023 10-K PDF 185	Y	N	N	Y	Y	Y	Y
AGR	939,000	510,592	54.38%	43,989,000	18,162,150	41.29%	2023 10-K, PDF 60, 102, 156	N	N	N	Y	N	Y	N
ALE	334,300	211,100	63.15%	5,013,400	3,344,500	66.71%	2023 10-K, PDF 76, 84, 107, 108	N	N	N	Y	Y	Y	N
AVA	291,320,000	153,512,904	52.70%	7,724,052,000	4,869,173,176	63.04%	2023 10-K, PDF 87, 95, 119	N	N	N	Y	Y	Y	N
BKH	472,700,000	248,800,000	52.63%	7,119,300	3,309,100	46.48%	2023 10-K, PDF 62, 80, 100	N	N	N	Y	Y	Y	N
CMS	1,520,000	831,000	54.67%	33,517,000	19,358,000	57.76%	2023 10-K, PDF 135-137	N	N	N	Y	Y	Y	N
CNP	1,672,000	957,000	57.24%	39,715,000	21,089,000	53.10%	2023 10-K, PDF 100	N	N	Y	Y	Y	Y	N
D	3,874,000	3,082,000	79.56%	113,100	78,000	68.97%	2023 10-K, PDF 73, 202	N	N	Y	Y	Y	Y	N
DTE	2,234,000	1,204,000	53.89%	46,452,000	32,292,000	69.52%	2023 10-K, PDF 122	N	N	Y	Y	Y	Y	N
DUK	7,290,000	6,073,000	83.31%	176,893,000	155,449,000	87.88%	2023 10-K, PDF 135	Y	N	N	Y	Y	Y	Y
ED	2,709,000	1,416,000	52.27%	66,331,000	44,555,000	67.17%	2023 10-K at 125	N	N	N	Y	Y	Y	N
EIX	2,809,000	2,786,000	99.18%	81,758,000	81,483,000	99.66%	2023 10-K page 14, 23, 67, 69, 75	Y	N	N	Y	Y	Y	Y
ES	2,237,500	1,462,000	65.34%	82,290,700	44,232,900	53.75%	2023 10-K at PDF 140	N	N	N	Y	Y	Y	N
ETR	2,976,618,000	2,780,050,549	93.40%	64,723,636,000	60,678,361,751	93.75%	2023 10-K at PDF 60, 219, 249, 250, 352, 38	Y	N	N	Y	Y	Y	Y
EVRG	1,282,400	1,282,400	100.00%	30,976,100	30,976,100	100.00%	2023 10-K, PDF 47, 78	Y	N	N	Y	Y	Y	Y
EXC	4,857,000	3,590,757	73.93%	105,883,000	92,548,821	87.41%	2023 10-K at 46, 199, 206	Y	N	Y	N	Y	Y	N
FE	2,331,000	2,128,000	91.29%	48,767,000	48,084,000	98.60%	2023 10-K, PDF 47, 146	Y	Y	N	Y	Y	Y	N
HE	409,457,000	282,087,000	68.89%	17,243,821,000	7,283,554,000	42.24%	2023 10-K, PDF 129	N	N	Y	Y	N	N	N
IDA	380,484,000	372,927,000	98.01%	8,552,212,000	8,323,531,000	97.33%	2023 10-K, PDF 104	Y	N	N	Y	Y	Y	Y
LNT	943,000	827,000	87.70%	21,237,000	17,833,000	83.97%	2023 10-K, PDF 92	Y	N	N	Y	Y	Y	Y
MGEE	148,572,000	96,555,000	64.99%	3,112,919,000	1,777,903,000	57.11%	2023 10-K, PDF 106, 107	N	N	N	Y	Y	Y	N
NEE	9,606,000	5,666,000	58.98%	177,489,000	91,469,000	51.54%	2023 10-K, PDF 79	N	N	N	Y	Y	Y	N
NWE	292,916,000	247,973,000	84.66%	7,600,652,000	6,071,021,000	79.88%	2023 10-K, PDF 122	Y	N	N	Y	Y	Y	Y
OGE	594,000	582,800	98.11%	12,943,700	12,642,600	97.67%	2023 10-K, PDF 95	Y	N	N	Y	Y	Y	Y
OTTR	308,621,000	104,873,000	33.98%	3,242,568,000	2,533,831,000	78.14%	2023 10-K, PDF 49	N	N	N	Y	Y	Y	N
PCG	22,967,000	16,381,898	71.33%	125698000	87504165.96	69.61%	2023 10-K, PDF 65, 95	N	N	Y	Y	N	Y	N
PEG	3,315,000	1,451,299	43.78%	48,245,000	28,933,000	59.97%	2023 10-K, 27, 29-30, 51	N	N	N	Y	Y	Y	N
PNW	824,640,000	824,640,000	100.00%	24,661,153,000	24,661,153,000	100.00%	2023 10-K, PDF 79	Y	N	N	Y	Y	Y	Y
POR	396,000,000	396,000,000	100.00%	11,208,000,000	11,208,000,000	100.00%	2023 10-K, PDF 46, 64	Y	N	N	Y	Y	Y	Y
PPL	1,556,000	1,396,104	89.72%	39,236,000	31,306,590	79.79%	2023 10-K PDF 11, 14, 57-65, 73	Y	N	Y	Y	N	Y	N
SO	6,437,000	4,782,000	74.29%	140,719,000	100,429,000	71.37%	2023 10-K, PDF 247	Y	N	N	Y	Y	Y	Y
SRE	4,342,000	2,971,092	68.43%	72,495,000	25,123,000	34.65%	2023 10-K PDF 118, 137, 218	N	N	N	Y	Y	Y	N
TXNM	247,690,000	232,655,000	93.93%	10,252,605,000	9,958,096,000	97.13%	2023 10-K, PDF 79	Y	N	N	Y	Y	Y	Y
WEC	2,408,600	1,531,867	63.60%	39,519,000	14,878,400	37.65%	2023 10-K PDF 57, 62, 64, 66, 117, 143	N	N	N	Y	Y	Y	N
XEL	2,775,000,000	2,356,000,000	84.90%	73,029,000	52,494,000	71.88%	2023 10-K PDF 26, 38	Y	N	N	Y	Y	Y	Y

I&E-RR-5-D

Reference Wellsboro Statement No. 2, p. 17, line 6 through p. 18, line 8. Identify each company from Value Line's Electric Utility East, Central, and West groups that were excluded from Mr. D'Ascendis and Mr. Kucan's Electric Utility Proxy Group. Specifically, state which of Mr. D'Ascendis and Mr. Kucan's criteria each company violated in order to be excluded.

Response Provided By:
Dylan W. D'Ascendis, Partner, ScottMadden, Inc.
Ryan M. Kucan, Manager, ScottMadden, Inc.

Date: May 30, 2025

Response:

Please refer to I&E-RR-5-D Attachment A.

I&E-RR-5-D Attachment A

Source: S&P Global Market Intelligence; SEC Company 10-Ks (as of February 28, 2025)
Numbers in ($000)

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AEE	1,723,000	1,477,991	85.78%	47,179,000	38,202,000	80.97%	2023 10-K PDF 144, 145	Y	N	N	Y	Y	Y	Y
AEP	4,214,000	3,830,000	90.89%	101,008,600	93,216,100	92.29%	2023 10-K PDF 185	Y	N	N	Y	Y	Y	Y
AGR	939,000	510,592	54.38%	43,989,000	18,162,150	41.29%	2023 10-K, PDF 60, 102, 156	N	N	N	Y	N	Y	N
ALE	334,300	211,100	63.15%	5,013,400	3,344,500	66.71%	2023 10-K, PDF 76, 84, 107, 108	N	N	N	Y	Y	Y	N
AVA	291,320,000	153,512,904	52.70%	7,724,052,000	4,869,173,176	63.04%	2023 10-K, PDF 87, 95, 119	N	N	N	Y	Y	Y	N
BKH	472,700,000	248,800,000	52.63%	7,119,300	3,309,100	46.48%	2023 10-K, PDF 62, 80, 100	N	N	N	Y	Y	Y	N
CMS	1,520,000	831,000	54.67%	33,517,000	19,358,000	57.76%	2023 10-K, PDF 135-137	N	N	N	Y	Y	Y	N
CNP	1,672,000	957,000	57.24%	39,715,000	21,089,000	53.10%	2023 10-K, PDF 100	N	N	Y	Y	Y	Y	N
D	3,874,000	3,082,000	79.56%	113,100	78,000	68.97%	2023 10-K, PDF 73, 202	N	N	Y	Y	Y	Y	N
DTE	2,234,000	1,204,000	53.89%	46,452,000	32,292,000	69.52%	2023 10-K, PDF 122	N	N	Y	Y	Y	Y	N
DUK	7,290,000	6,073,000	83.31%	176,893,000	155,449,000	87.88%	2023 10-K, PDF 135	Y	N	N	Y	Y	Y	Y
ED	2,709,000	1,416,000	52.27%	66,331,000	44,555,000	67.17%	2023 10-K at 125	N	N	N	Y	Y	Y	N
EIX	2,809,000	2,786,000	99.18%	81,758,000	81,483,000	99.66%	2023 10-K page 14, 23, 67, 69, 75	Y	N	N	Y	Y	Y	Y
ES	2,237,500	1,462,000	65.34%	82,290,700	44,232,900	53.75%	2023 10-K at PDF 140	N	N	N	Y	Y	Y	N
ETR	2,976,618,000	2,780,050,549	93.40%	64,723,636,000	60,678,361,751	93.75%	2023 10-K at PDF 60, 219, 249, 250, 352, 38	Y	N	N	Y	Y	Y	Y
EVRG	1,282,400	1,282,400	100.00%	30,976,100	30,976,100	100.00%	2023 10-K, PDF 47, 78	Y	N	N	Y	Y	Y	Y
EXC	4,857,000	3,590,757	73.93%	105,883,000	92,548,821	87.41%	2023 10-K at 46, 199, 206	Y	N	Y	N	Y	Y	N
FE	2,331,000	2,128,000	91.29%	48,767,000	48,084,000	98.60%	2023 10-K, PDF 47, 146	Y	Y	N	Y	Y	Y	N
HE	409,457,000	282,087,000	68.89%	17,243,821,000	7,283,554,000	42.24%	2023 10-K, PDF 129	N	N	Y	Y	N	N	N
IDA	380,484,000	372,927,000	98.01%	8,552,212,000	8,323,531,000	97.33%	2023 10-K, PDF 104	Y	N	N	Y	Y	Y	Y
LNT	943,000	827,000	87.70%	21,237,000	17,833,000	83.97%	2023 10-K, PDF 92	Y	N	N	Y	Y	Y	Y
MGEE	148,572,000	96,555,000	64.99%	3,112,919,000	1,777,903,000	57.11%	2023 10-K, PDF 106, 107	N	N	N	Y	Y	Y	N
NEE	9,606,000	5,666,000	58.98%	177,489,000	91,469,000	51.54%	2023 10-K, PDF 79	N	N	N	Y	Y	Y	N
NWE	292,916,000	247,973,000	84.66%	7,600,652,000	6,071,021,000	79.88%	2023 10-K, PDF 122	Y	N	N	Y	Y	Y	Y
OGE	594,000	582,800	98.11%	12,943,700	12,642,600	97.67%	2023 10-K, PDF 95	Y	N	N	Y	Y	Y	Y
OTTR	308,621,000	104,873,000	33.98%	3,242,568,000	2,533,831,000	78.14%	2023 10-K, PDF 49	N	N	N	Y	Y	Y	N
PCG	22,967,000	16,381,898	71.33%	125698000	87504165.96	69.61%	2023 10-K, PDF 65, 95	N	N	Y	Y	N	Y	N
PEG	3,315,000	1,451,299	43.78%	48,245,000	28,933,000	59.97%	2023 10-K, 27, 29-30, 51	N	N	N	Y	Y	Y	N
PNW	824,640,000	824,640,000	100.00%	24,661,153,000	24,661,153,000	100.00%	2023 10-K, PDF 79	Y	N	N	Y	Y	Y	Y
POR	396,000,000	396,000,000	100.00%	11,208,000,000	11,208,000,000	100.00%	2023 10-K, PDF 46, 64	Y	N	N	Y	Y	Y	Y
PPL	1,556,000	1,396,104	89.72%	39,236,000	31,306,590	79.79%	2023 10-K PDF 11, 14, 57-65, 73	Y	N	Y	Y	N	Y	N
SO	6,437,000	4,782,000	74.29%	140,719,000	100,429,000	71.37%	2023 10-K, PDF 247	Y	N	N	Y	Y	Y	Y
SRE	4,342,000	2,971,092	68.43%	72,495,000	25,123,000	34.65%	2023 10-K PDF 118, 137, 218	N	N	N	Y	Y	Y	N
TXNM	247,690,000	232,655,000	93.93%	10,252,605,000	9,958,096,000	97.13%	2023 10-K, PDF 79	Y	N	N	Y	Y	Y	Y
WEC	2,408,600	1,531,867	63.60%	39,519,000	14,878,400	37.65%	2023 10-K PDF 57, 62, 64, 66, 117, 143	N	N	N	Y	Y	Y	N
XEL	2,775,000,000	2,356,000,000	84.90%	73,029,000	52,494,000	71.88%	2023 10-K PDF 26, 38	Y	N	N	Y	Y	Y	Y

	2024		
	Interest Charges	**Long-Term Debt**	**Debt Cost**
Dominion Energy Inc.	$ 2,023.00	$ 38,169.00	5.30%
Duke Energy Corporation	3,585.00	77,297.00	4.64%
Consolidated Edison Inc.	1,250.00	25,040.00	4.99%
Eversource Energy	1,175.74	26,133.50	4.50%
Exelon Corporation	2,036.00	43,554.00	4.67%
FirstEnergy Corp	1,144.00	22,688.00	5.04%
NextEra Energy Inc	2,235.00	72,385.00	3.09%
Public Service Enterprise Group Inc.	882.00	19,117.00	4.61%
PPL Corporation	758.00	15,952.00	4.75%
	Range:	**Low**	**3.09%**
		High	**5.30%**
		Average	**4.62%**

Source:
Compustat (S&P Global Market Intelligence - Data Management Solutions)
Yearly data updates typically provided late April of each year
(data in millions)

Accessed on May 14, 2025

Mergent Bond Record
A-Rated Public Utility Bond Yields

Month	Yield
May 2024	5.74%
June 2024	5.61%
July 2024	5.64%
August 2024	5.38%
September 2024	5.20%
October 2024	5.41%
November 2024	5.55%
December 2024	5.58%
January 2025	5.87%
February 2025	5.73%
March 2025	5.72%
April 2025	5.91%
Average	**5.61%**

Source:
Mergent Bond Record
May 2025

Dividend Yields of Proxy Group

Company	Dominion Energy Inc.	Duke Energy Corporation	Consolidated Edison Inc.	Eversource Energy	Exelon Corporation	FirstEnergy Corp	NextEra Energy Inc	Public Service Enterprise Group Inc.	PPL Corporation
Symbol	*D*	*DUK*	*ED*	*ES*	*EXC*	*FE*	*NEE*	*PEG*	*PPL*
Div	2.67	4.30	3.60	3.17	1.72	1.86	2.50	2.68	1.17
52-wk low	47.99	99.21	87.28	52.28	34.01	37.58	61.72	71.89	27.24
52-wk high	61.97	125.27	114.87	69.01	48.11	44.97	86.10	95.22	36.70
Spot Price	53.81	113.07	100.58	62.91	42.97	41.23	72.11	77.59	33.79
Spot Div Yield	4.96%	3.80%	3.58%	5.04%	4.00%	4.51%	3.47%	3.45%	3.46%
52-wk Div Yield	4.86%	3.83%	3.56%	5.23%	4.19%	4.51%	3.38%	3.21%	3.66%
Average	4.91%	3.82%	3.57%	5.13%	4.10%	4.51%	3.42%	3.33%	3.56%

	Average
Spot Div Yield	**4.03%**
52-wk Div Yield	**4.05%**
Average	**4.04%**

Source: Barron's May 14, 2025
Value Line May 9, 2025

Five-Year Growth Estimate Forecast for Proxy Group (Actual)

Company	Symbol	S&P	Zacks	Value Line	Average
		Source			
Dominion Energy Inc.	D	11.39%	13.60%	6.00%	10.33%
Duke Energy Corporation	DUK	6.38%	6.30%	6.00%	6.23%
Consolidated Edison Inc.	ED	5.79%	5.60%	6.00%	5.80%
Eversource Energy	ES	5.62%	5.70%	5.50%	5.61%
Exelon Corporation	EXC	6.42%	6.40%	NMF	6.41%
FirstEnergy Corp	FE	6.09%	6.40%	4.50%	5.66%
NextEra Energy Inc	NEE	7.70%	7.70%	8.50%	7.97%
Public Service Enterprise Group Inc.	PEG	6.65%	6.80%	7.00%	6.82%
PPL Corporation	PPL	7.40%	7.50%	7.50%	7.47%
Average:		**7.05%**	**7.33%**	**6.38%**	**6.92%**

Sources Date:
(From Internet)
May 15, 2025, May 14, 2025, and May 9, 2025

Five-Year Growth Estimate Forecast for Proxy Group (Adjusted)

Company	Symbol	S&P	Zacks	Value Line	Average
		Source			
Dominion Energy Inc.	D	11.39%	X	6.00%	8.70%
Duke Energy Corporation	DUK	6.38%	6.30%	6.00%	6.23%
Consolidated Edison Inc.	ED	5.79%	5.60%	6.00%	5.80%
Eversource Energy	ES	5.62%	5.70%	5.50%	5.61%
Exelon Corporation	EXC	6.42%	6.40%	NMF	6.41%
FirstEnergy Corp	FE	6.09%	6.40%	4.50%	5.66%
NextEra Energy Inc	NEE	7.70%	7.70%	8.50%	7.97%
Public Service Enterprise Group Inc.	PEG	6.65%	6.80%	7.00%	6.82%
PPL Corporation	PPL	7.40%	7.50%	7.50%	7.47%
Average:		**7.05%**	**6.55%**	**6.38%**	**6.74%**

Expected Market Cost Rate of Equity
Using Data for the Proxy Group of Electric Companies
5-Year Forecasted Growth Rates

	Time Period	Adjusted Dividend Yield (1)	Growth Rate (2)	Expected Return on Equity (3=1+2)
(1)	**52-Week Average** **Ending:** May 14, 2025	4.05%	6.74%	10.79%
(2)	**Spot Price** **Ending:** May 14, 2025	4.03%	6.74%	10.77%
(3)	**Average:**	**4.04%**	**6.74%**	**10.78%**

Sources: Value Line May 9, 2025
Barron's May 14, 2025

Company	Beta
Dominion Energy Inc.	0.75
Duke Energy Corporation	0.70
Consolidated Edison Inc.	0.65
Eversource Energy	0.85
Exelon Corporation	NMF
FirstEnergy Corp	0.75
NextEra Energy Inc	0.90
Public Service Enterprise Group Inc.	0.90
PPL Corporation	0.90
Average beta for CAPM	**0.80**

Source:
Value Line
May 9, 2025

Risk-Free Rate

10-Year Treasury Note	**Yield**
3Q 2025	4.20
4Q 2025	4.10
1Q 2026	4.10
2Q 2026	4.10
3Q 2026	4.10
2026-2030	4.00
Average	**4.10**

Source:
Blue Chip
May 1, 2025 and November 27, 2024

S&P 500 Historical Return

Year	Return
2024	25.02
2023	26.29
2022	-18.11
2021	28.71
2020	18.4
2019	31.49
2018	-4.38
2017	21.83
2016	11.96
2015	1.38
2014	13.69
2013	32.39
2012	16
2011	2.11
2010	15.06
2009	26.46
2008	-37
2007	5.49
2006	15.79
2005	4.91
2004	10.88
2003	28.68
2002	-22.1
2001	-11.89
2000	-9.1
1999	21.04
1998	28.58
1997	33.36
1996	22.96
1995	37.58
1994	1.32
1993	10.08
1992	7.62
1991	30.47
1990	-3.1
1989	31.69
1988	16.61
1987	5.25
1986	18.67
1985	31.73
1984	6.27
1983	22.56
1982	21.55
1981	-4.91
1980	32.42
1979	18.44
1978	6.56
1977	-7.18
1976	23.84
1975	37.2
1974	-26.47
1973	-14.66
1972	18.98

1971	14.31
1970	4.01
1969	-8.5
1968	11.06
1967	23.98
1966	-10.06
1965	12.45
1964	16.48
1963	22.8
1962	-8.73
1961	26.89
1960	0.47
1959	11.96
1958	43.36
1957	-10.78
1956	6.56
1955	31.56
1954	52.62
1953	-0.99
1952	18.37
1951	24.02
1950	31.71
1949	18.79
1948	5.5
1947	5.71
1946	-8.07
1945	36.44
1944	19.75
1943	25.9
1942	20.34
1941	-11.59
1940	-9.78
1939	-0.41
1938	31.12
1937	-35.03
1936	33.92
1935	47.67
1934	-1.44
1933	53.99
1932	-8.19
1931	-43.34
1930	-24.9
1929	-8.42
1928	43.61
1927	37.49
1926	11.62
Average	**12.29**

Source:
https://www.slickcharts.com/sp500/returns#google_vignette
Accessed on May 14, 2025

Required Rate of Return on Market as a Whole Forecasted

	Dividend Yield	+	Growth Rate	=	Expected Market Return
Value Line Estimate	2.30%		11.58%	(a)	13.88%
S&P 500 Historical Return					12.29%
Average Expected Market Return				=	**13.09%**

(a) Value Line forecast for the 3 to 5 year index appreciation is 55% ((1+55%)^.25)-1)

Sources:

S&P 500 Historical Rate	1926-2024	12.29%
Value Line Dividend Yield	5/16/2025	2.30%
Valueline Appreciation Potential	5/16/2025	55.00%

CAPM with Forecasted Return

Re		Required return on individual equity security
Rf		Risk-free rate
Rm		Required return on the market as a whole
Be		Beta on individual equity security
Re	=	Rf + Be(Rm - Rf)
Rf	=	4.10
Rm	=	13.09
Be	=	0.80
Re	=	**11.29**

Sources: Value Line May 9, 2025
Blue Chip May 1, 2025 and November 27, 2024

CAPM Using Kroll ERP & 20-Year U.S. Treasury

Re		Required return on individual equity security
Rf		Risk-free rate
ERP		Equity Risk Premium
Be		Beta on individual equity security
Re	=	Rf+Be(ERP)
Rf	=	4.95
ERP	=	5.50
Be	=	0.80
Re	=	**9.35**

Sources: Value Line May 9, 2025
Kroll April 15, 2025
CNBC May 14, 2025

Average CAPM Result **10.32**

I&E-RR-11-D

Reference Citizens' Exhibit_(HSG-1), Schedule C1, concerning the revenue requirement calculation. Provide the calculation for the gross revenue conversion factor for the HTY, FTY, and FPFTY to account for the need to gross-up revenue for taxes, uncollectibles, assessments, etc.

Response Provided By:
Howard Gorman, President, HSG Group, Inc.

Date: May 23, 2025

Response:

The calculation of the Revenue increase needed for the FPFTY is presented below.
There was no gross-up for uncollectibles or for assessments; however, including these amounts would cause the Revenue increase to be higher by a minor amount.

A	Rate base	17,092,345	A = Sch C1, Line 3(
B	Required return	8.490%	B= Schedule C1-2
C	Operating income required	1,451,140	C= A * B
D	Operating income at present rates	250,378	D= Sch C1, Line 28
E	Operating income deficiency	1,200,762	E= C - B
F	Gross-up for income tax	140.631%	F= 1 / (1-28.89%)
G	Gross-up for GRT and Income Tax	149.4488%	G= F / (1-5.90%)
H	Revenue deficiency- Distribution	1,794,525	H= E * G
I	Additional GRT	105,877	I= H * 5.90%
J	Additional Income tax expense	487,886	J= H - E - I
K	Increase in Distrbution revenue required	29.636%	K = H / 6,055,143 (I
L	Proposed revenue- Distribution	7,849,668	L = H + 6,055,143 (I

I&E-RR-11-D

Reference Wellsboro Exhibit_(HSG-1), Schedule C1, concerning the revenue requirement calculation. Provide the calculation for the gross revenue conversion factor for the HTY, FTY, and FPFTY to account for the need to gross-up revenue for taxes, uncollectibles, assessments, etc.

Response Provided By:
Howard Gorman, President, HSG Group, Inc.

Date: May 30, 2025

Response:
The calculation of the Revenue increase needed for the FPFTY is presented below.
There was no gross-up for uncollectibles or for assessments; however, these amounts would cause the Revenue increase to be higher by a minor amount.

A	Rate base	25,857,280	A = Sch C1, Line 31
B	Required return	8.18%	B = Sch C1-2
C	Operating income required	2,115,126	C = A * B
D	Operating income at present rates	175,071	D = Sch C1, Line 28
E	Operating income deficiency	1,940,054	E = C - B
F	Gross-up for income tax	1.40631	F = 1 / (1-28.80%)
G	Gross-up for GRT	1.49449	G = F / (1-5.90%)
H	Revenue deficiency- Computed	2,899,388	H = E * G
HH	Revenue deficiency- Requested	2,899,388	HH = Min (H, 5,000,000)
I	Additional GRT	171,064	I = HH * 5.90%
J	Additional Income tax expense	788,270	J = HH - E - I
K	Increase in Distrbution revenue required	45.29%	K = HH / 6,401,996
L	Proposed revenue	9,301,384	L = HH + 6,401,996

I&E-RR-7-D

Reference Citizens' Statement No. 2, p. 4, lines 10-11:

A. State whether Mr. D'Ascendis or Mr. Kucan are aware of any electric utilities throughout the United States that have been granted a Commission-authorized 11.65% or higher cost of common equity in the past two years.

B. If the answer to I&E-RR-7-D Part A is yes, identify which company/companies have been authorized such cost of common equity, in what jurisdiction, and docket numbers associated with each instance.

Response Provided By:
Dylan W. D'Ascendis, Partner, ScottMadden, Inc.
Ryan M. Kucan, Manager, ScottMadden, Inc.

Date: May 30, 2025

Response:

A. Messrs. D'Ascendis and Kucan have not conducted an exhaustive study of all Commission orders, but they are not aware of any instances where a Commission has approved an electric ROE of 11.65% or higher in a base rate proceeding.

B. N/A.

I&E-RR-7-D

Reference Wellsboro Statement No. 2, p. 4, lines 10-11:

A. State whether Mr. D'Ascendis or Mr. Kucan are aware of any electric utilities throughout the United States that have been granted a Commission-authorized 11.65% or higher cost of common equity in the past two years.

B. If the answer to I&E-RR-7-D Part A is yes, identify which company/companies have been authorized such cost of common equity, in what jurisdiction, and docket numbers associated with each instance.

Response Provided By:
Dylan W. D'Ascendis, Partner, ScottMadden, Inc.
Ryan M. Kucan, Manager, ScottMadden, Inc.

Date: May 30, 2025

Response:

A. Messrs. D'Ascendis and Kucan have not conducted an exhaustive study of all Commission orders, but they are not aware of any instances where a Commission has approved an electric ROE of 11.65% or higher in a base rate proceeding.
B. N/A.

I&E Statement No. 2-SR
Witness: Christopher Keller

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

WELLSBORO ELECTRIC COMPANY
Docket No. R-2025-3054392

&

CITIZENS' ELECTRIC COMPANY OF LEWISBURG, PA
Docket No. R-2025-3054394

Surrebuttal Testimony

of

Christopher Keller

Bureau of Investigation and Enforcement

Concerning:

Rate of Return

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INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Christopher Keller. My business address is Pennsylvania Public Utility Commission, Commonwealth Keystone Building, 400 North Street, Harrisburg, PA 17120.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by the Pennsylvania Public Utility Commission (Commission) in the Bureau of Investigation & Enforcement (I&E) as a Fixed Utility Financial Analyst.

Q. ARE YOU THE SAME CHRISTOPHER KELLER WHO IS RESPONSIBLE FOR THE DIRECT TESTIMONY CONTAINED IN I&E STATEMENT NO. 2 AND THE SCHEDULES IN I&E EXHIBIT NO. 2?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR SURREBUTTAL TESTIMONY?

A. The purpose of my surrebuttal testimony is to respond to the rebuttal testimony of Wellsboro Electric Company (Wellsboro) and Citizens' Electric Company of Lewisburg (Citizens'), collectively referred to in this testimony as "the

Companies," witness Dylan W. D'Ascendis[1] and Office of Consumer Advocate (OCA) witness Christopher C. Walters[2] regarding rate of return topics including the cost of common equity and the overall fair rate of return, which will be applied to the Companies' rate base. I will also address the Companies' size adjustment and performance factor claims discussed by Mr. D'Ascendis, Citizens' witness Nathan Johnson,[3] and Wellsboro witness Byron Farnsworth, Jr.[4]

Q. DOES YOUR SURREBUTTAL TESTIMONY INCLUDE AN ACCOMPANYING EXHIBIT.

A. No, however, I will make references to my direct testimony[5] and its accompanying exhibit.[6]

SUMMARY OF MR. WALTERS' REBUTTAL TESTIMONY

Q. SUMMARIZE MR. WALTERS' RESPONSE IN REBUTTAL TESTIMONY TO YOUR RECOMMENDATIONS MADE IN DIRECT TESTIMONY.

A. Mr. Walters takes issue with my overall return on equity recommendation stating that my return on equity recommendation would be the highest allowed return on equity for an electric distribution company since at least 2010 and deviates from

1 Citizens'/Wellsboro Statement No. 2R.
2 OCA Statement No. 2R (Citizens') and OCA Statement No. 2R (Wellsboro).
3 Citizens' Statement No. 4R.
4 Wellsboro Statement No. 4R.
5 I&E Statement No. 2.
6 I&E Exhibit No. 2.

industry norms for distribution-only electric utilities and vertically integrated electric utilities. Mr. Walters disagrees with certain aspects of my Discounted Cash Flow (DCF) analysis claiming the growth rate in my DCF analysis is excessive and I should have considered a multiple-stage DCF model. Finally, Mr. Walters claims that I failed to consider the results of cost of equity models other than the DCF model.[7]

Q. WHAT IS MR. WALTERS' SPECIFIC CRITICISM REGARDING YOUR DCF ANALYSIS?

A. Mr. Walters opines that the result of my DCF analysis is unreasonably high because it exceeds the projected growth rate of the U.S. economy which he bases on the projected long-term U.S. Gross Domestic Product (GDP) at the time of his analysis of 4.09%. Mr. Walters states that the GDP growth projections are a reasonable upper limit as public utilities cannot sustain a growth rate that exceeds the U.S. economy. Mr. Walters states that I believe that utilities can indefinitely sustain a growth rate that exceeds the growth rate of the U.S. economy. Finally, Mr. Walters opines I should have considered using a multi-stage DCF model in addition to my constant growth DCF model in order to balance the result of my "flawed" constant growth rate DCF result. Mr. Walters recalculates my DCF result to include a multi-stage DCF result which he averages with my constant

[7] OCA Statement No. 2R (Citizens'), p. 4, lines 5-19 and OCA Statement No. 2R (Wellsboro), p. 4, lines 3-17.

growth rate model result to produce an overall DCF analysis of 9.7% which is in between his recommended range of 9.00% to 10.00%.[8]

Q. HOW DO YOU RESPOND TO MR. WALTERS' CRITICISMS OF YOUR DCF ANALYSIS?

A. First, it should be noted, in the context of recommending an appropriate return on equity and overall rate of return, I&E's role is to perform an unbiased analysis using current and reputable sources. In determining an appropriate growth rate for my DCF analysis, I relied upon the forecasted earnings estimates from S&P, Zacks, and Value Line.[9] These resources are trusted and used industry wide, including by most Company, advocate, and Commission witnesses who submit rate of return testimony. Mr. Walters, Mr. D'Ascendis, and I all utilize these sources in our respective DCF analyses.

Next, the estimates I use from the sources listed above are five-year growth forecasts which are not short-term, nor are they intended to be viewed as sustainable indefinitely as Mr. Walters seems to suggest is my intention.[10] I believe the five-year growth estimates are reasonable as they cover the time period of the Fully Projected Future Test Year (FPFTY) and rate case filing frequency of many utilities. In this proceeding, I&E witness Zachari Walker determined the

[8] OCA Statement No. 2R (Citizens'), p. 8, line 1 through p. 10, line 10 and OCA Statement No. 2R (Wellsboro), p. 8, line 1 through p. 10, line 10.
[9] I&E Exhibit No. 2, Schedule 7.
[10] OCA Statement No. 2R (Citizens'), p. 9, lines 11-15 and OCA Statement No. 2R (Wellsboro), p. 9, lines 11-15.

rate case filing frequency to be 36 months (3 years)[11] and 60 months (5 years)[12] for Citizens' and Wellsboro, respectively.

Additionally, the Commission has repeatedly confirmed I&E's DCF methodology for determining a fair return on common equity. Specifically, in the 2020 Columbia Gas rate case, the 2021 Aqua Pennsylvania, Inc. rate case, the 2023 Columbia Water rate case, and mostly recently, the 2023 Pennsylvania-American Water Company rate case, the Commission agreed with the ALJ's recommendation to use I&E's cost of equity methodology, which included using five-year growth estimates in the DCF analysis.[13]

Finally, Mr. Walters acknowledges that despite my DCF analysis based on the constant growth rate DCF model being "flawed," my DCF result of 10.78% is nearly identical to his DCF result based on the constant growth rate model of 10.79%.[14]

Q. PLEASE RESPOND TO MR. WALTERS' ASSERTION THAT YOU RELIED SOLELY ON THE DCF.

A. As stated in my direct testimony, while my recommendation was based on the

[11] R-2025-3054394, I&E Statement No. 1, p. 9, lines 15-20.
[12] R-2025-3054392, I&E Statement No. 1, p. 9, lines 14-17.
[13] *Pa. PUC v. Columbia Gas of Pennsylvania, Inc.*, Docket No. R-2020-3018835, pp. 141-143 (Order Entered February 19, 2021); *Pa. PUC v. Aqua Pennsylvania, Inc.*, Docket Nos. R-2021-3027385 & R-2021-3027386, pp. 154-155 (Order Entered May 16, 2022); *Pa. PUC v. Columbia Water Company*, Docket No. R-2023-3040258, p. 105 (Order Entered January 18, 2024); and *Pa. PUC v. Pennsylvania-American Water Company*, Docket Nos. R-2023-3043189 and R-2023-3043190, pp. 194-195 (Order Entered July 22, 2024).
[14] OCA Statement No. 2R (Citizens'), p. 11, lines 5-8 and fn. 6 and OCA Statement No. 2R (Wellsboro), p. 11, lines 5-8.

results of my DCF analysis, I also employed the Capital Asset Pricing Model (CAPM) only as a comparison because the DCF method is the most reliable.[15] The DCF method has the most wide-spread regulatory acceptance, and while the Commission has more recently based its ROE decisions on a combination of methods, I still stand by my method of using the DCF with a CAPM comparison.

SUMMARY OF MR. D'ASCENDIS' REBUTTAL TESTIMONY

Q. SUMMARIZE MR. D'ASCENDIS' RESPONSE IN REBUTTAL TESTIMONY TO YOUR RATE OF RETURN RECOMMENDATIONS.

A. Mr. D'Ascendis disputes my recommendations regarding an overall fair rate of return. Specifically, Mr. D'Ascendis claims that I failed to consider the results of cost of equity models other than the DCF model. Next, he criticizes my application of the CAPM, claiming that I have incorrectly relied on the 10-year Treasury Bond for my risk-free rate and have not employed the Empirical CAPM (ECAPM). Further, he claims that I fail to account for the Companies' size-specific risk, takes issue with my dismissal of his Non-Price Regulated Proxy Group, and disagrees with my recommended disallowance of additional basis points for management performance. Finally, although Mr. D'Ascendis expresses disagreement with my rate of return analysis for the reasons stated above, he states

[15] I&E Statement No. 2, pp. 20-21.

that since our analyses led to comparable results, he will not discuss his concerns with our approaches or the bases of their recommendations.[16]

Q. DID MR. D'ASECNDIS PROVIDE AN UPDATE TO HIS RATE OF RETURN ANALYSIS?

A. Yes. Mr. D'Ascendis provided an update to its analysis using data through July 18, 2025 and updated his proxy based on 2024 data. Ultimately, Mr. D'Ascendis' return on equity recommendation of 11.65% from his direct testimony remains unchanged.[17]

DISCOUNTED CASH FLOW

Q. SUMMARIZE MR. D'ASCENDIS' REBUTTAL TESTIMONY REGARDING YOUR DCF ANALYSIS.

A. Mr. D'Ascendis opines that I have inappropriately relied solely on the DCF model for my cost of equity recommendations.[18] He presents three cases where he claims the Commission has considered multiple cost of equity models.[19]

[16] Citizens'/Wellsboro Statement No. 2R, p. 7, lines 5-13.
[17] Citizens'/Wellsboro Statement No. 2R, p. 4, line 3 through p. 6, line 3.
[18] Citizens'/Wellsboro Statement No. 2R, p. 7, lines 7-9.
[19] Citizens'/Wellsboro Statement No. 2R, p. 16, line 26, through p 18, line 7.

Q. PLEASE RESPOND TO MR. D'ASCENDIS' ASSERTION THAT YOU RELIED SOLELY ON THE DCF.

A. As stated in my direct testimony, while my recommendation was based on the results of my DCF analysis, I also employed the CAPM only as a comparison because the DCF method is the most reliable.[20] The DCF method has the most wide-spread regulatory acceptance, and while the Commission has more recently based its ROE decisions on a combination of methods, I still stand by my method of using the DCF with a CAPM comparison.

Q. WHICH CASES DOES MR. D'ASCENDIS MENTION WHERE HE CLAIMS THE COMMISSION HAS CONSIDERED MULTIPLE COST OF EQUITY MODELS?

A. Mr. D'Ascendis mentions the 2013 Columbia Water Company (Columbia Water),[21] the 2014 Emporium Water Company (Emporium),[22] and the 2021 Aqua Pennsylvania, Inc. (Aqua)[23] cases to suggest the Commission has considered multiple cost of common equity models.[24]

[20] I&E Statement No. 2, pp. 20-21.
[21] *Pa. PUC v. The Columbia Water Company*, Docket No. R-2013-2360798 (Order Entered January 23, 2014).
[22] *Pa. PUC v. Emporium Water Company*, Docket No. R-2014-2402324 (Order Entered January 28, 2015).
[23] *Pa. PUC v. Aqua Pennsylvania, Inc.,* Docket Nos. R-2021-3027385 & R-2021-3027386 (Order Entered May 16, 2022).
[24] Citizens'/Wellsboro Statement No. 2R, pp. 16-18.

Q. WHAT COMMENTS DO YOU HAVE REGARDING THE CASES MR. D'ASCENDIS MENTIONS?

A. First, within the citation Mr. D'Ascendis presents regarding the Columbia Water case, the Commission specifically states that it used the DCF method as the foundation in determining the cost of equity.[25] Any adjustments to the cost of equity after the fact are at the Commission's discretion and independent of the result of any other cost of equity model. Regarding the Emporium case, the Commission simply summarized the recommendations presented by OCA, I&E, and Emporium; it did not specifically comment on which model(s) it relied on.[26] Regarding the Aqua case, as I stated in my direct testimony, Aqua's return on equity of 10.00% was well above the national average for water utility base rate cases. Finally, as stated in my direct testimony, I did in fact employ the CAPM as a comparison to my DCF result.[27]

CAPITAL ASSET PRICING MODEL

Q. SUMMARIZE MR. D'ASCENDIS' RESPONSE TO YOUR CAPM ANALYSIS.

A. Mr. D'Ascendis disputes my use of the 10-year U.S. Treasury Note as a proxy to measure the risk-free rate that I use in my CAPM analysis. He also disagrees with

[25] Citizens'/Wellsboro Statement No. 2R, p. 16, lines 30-33.
[26] Citizens'/Wellsboro Statement No. 2R, p. 17, lines 7-25.
[27] I&E Statement No. 2, p. 20, lines 1-9.

my exclusion of the ECAPM method of computing the Companies' return on equity.

Risk-Free Rate

Q. WHAT IS MR. D'ASCENDIS' RESPONSE TO YOUR USE OF THE YIELD ON THE 10-YEAR U.S. TREASURY NOTE?

A. Mr. D'Ascendis claims his use of the yield on a 30-year U.S. Treasury Bond is more appropriate than my use of the yield on a 10-year Treasury Note because it better reflects the life of the underlying investment. He also opines that long-term treasury notes are not subject to maturity risk as the cost of equity is a long-term concept, and the investment horizon of an individual investor is irrelevant. [28]

Q. IS THE LIFE OF THE INVESTMENT THE ONLY FACTOR THAT SHOULD BE CONSIDERED IN THE CHOICE OF A RISK-FREE RATE?

A. No. The risk-free rate is the return that can be earned without accepting any risk, and while the life of the investment can be considered in the choice of risk-free rates, the most important consideration is that the rate be as risk-free as possible. As explained in my direct testimony, I chose the 10-year Treasury Note as it mitigates the shortcomings of the short-term Treasury-Bill and the 30-year Treasury Bond.[29] Although long-term Treasury Bonds have less risk of being

[28] Citizens'/Wellsboro Statement No. 2R, pp. 24-25.
[29] I&E Statement No. 2, p. 33-34.

influenced by federal policies, they have substantial maturity risk associated with market risk. In addition, long-term Treasury Bonds bear the risk of unexpected inflation. As such, my choice of a 10-year Treasury Note is appropriate. Further, as also pointed out in my direct testimony, the Commission recently agreed with I&E that the 10-year Treasury Note is the superior measure of the risk-free rate of return.[30]

Q. DO YOU AGREE WITH MR. D'ASCENDIS' ASSERTION THAT LONG-TERM TREASURY BONDS ARE NOT SUBJECT TO MATURITY RISK?

A. No. As discussed in my direct testimony, while long-term Treasury Bonds exhibit more stability, they are not risk-free. Long-term Treasury Bonds have substantial maturity risk associated with market risk and the risk of unexpected inflation which is why long-term treasuries normally offer higher yields to compensate investors for these risks.[31]

[30] *Pa. PUC v. UGI Utilities, Inc. – Electric Division*, Docket No. R-2017-2640058 (Order Entered October 25, 2018). *See generally* Disposition of Capital Asset Pricing Model (CAPM), p. 99; *Pa. PUC v. Aqua Pennsylvania, Inc.*, Docket Nos. R-2021-3027385 & R-2021-3027386, p. 154 (Order Entered May 16, 2022); *Pa. PUC v. Columbia Water Company*, Docket No. R-2023-3040258 (Order Entered January 18, 2024). *See generally* Disposition of Cost of Common Equity, pp. 107-108; *Pa. PUC v. Pennsylvania-American Water Company*, Docket Nos. R-2023-3043189 & R-2023-3043190 (Order Entered July 22, 2024). *See generally* Disposition of Capital Asset Pricing Model (CAPM), pp. 171-172.

[31] I&E Statement No. 2, p. 33, line 21 through p. 34, line 4.

Exclusion of the ECAPM

Q. PLEASE SUMMARIZE MR. D'ASCENDIS' RESPONSE TO YOUR EXCLUSION OF THE ECAPM IN YOUR ANALYSIS.

A. Mr. D'Ascendis asserts that the empirical Security Market Line (SML) described by the traditional CAPM is not as steeply sloped as the CAPM model predicts and that tests of the CAPM have measured the level of which security returns and betas are related as predicted by the CAPM.[32]

Q. WHY HAVE YOU EXCLUDED THE ECAPM FROM YOUR ANALYSIS?

A. The ECAPM is a modified version of the CAPM which attempts to address the belief that the actual risk vs. return correlation is flatter than what is predicted by the CAPM. The implication is that the CAPM underestimates returns with lower levels of risk and over-estimates the returns associated with higher levels of risk. The model entails assigning 25% weight to the market beta and 75% weight to the individual company or proxy group.[33]

Further, the use of the ECAPM in estimating the cost of capital does not increase the validity of the result but merely adds another measure of subjectivity to the CAPM, attempting to make the SML more accurate. The ECAPM reduces the purpose of the beta, which is the only company-specific variable in the CAPM

[32] Citizens'/Wellsboro Statement No. 2R, pp. 21-23.
[33] David C. Parcell, "The Cost of Capital – A Practitioner's Guide," 2010 Edition, p. 104.

model. This additional layer of subjectivity provides an even stronger basis to rely on the DCF as the primary method to calculate a utility's cost of equity.

Q. HAVE YOU CHANGED YOUR CAPM RETURN ON EQUITY RECOMMENDATION AS A RESULT OF MR. D'ASCENDIS' REBUTTAL TESTIMONY?

A. No. Even though it is lower, I continue to recommend using my CAPM result of 10.32%[34] only as a comparison to my higher DCF result of 10.78%.[35]

NON-PRICE REGULATED PROXY GROUP

Q. WHAT WAS YOUR RECOMMENDATION IN DIRECT TESTIMONY CONCERNING MR. D'ASCENDIS' UTILIZATION OF A NON-REGULATED PROXY GROUP?

A. I recommended the Commission reject all analyses performed using the non-price regulated company proxy group as it is highly speculative and subjective. Mr. D'Ascendis' non-regulated proxy group in effect blends the CE approach into the DCF, RP, and CAPM models, and I cited that the Commission has ruled on the use of non-utility companies in comparable groups for the CE approach as being highly speculative.[36]

[34] I&E Exhibit No. 1, Schedule 13.
[35] I&E Exhibit No. 1, Schedule 8.
[36] I&E Statement No. 2, pp. 42-43.

Q. SUMMARIZE MR. D'ASCENDIS RESPONSE REGARDING YOUR DISAGREEMENT WITH HIS USE OF A NON-REGULATED PROXY GROUP.

A. In rebuttal testimony, Mr. D'Ascendis attempts to justify the use of the companies contained in his non-regulated proxy group based on the betas and standard errors of the regression being similar to that of the companies in his electric company proxy group and, therefore, opining they are similar to the Companies.[37]

Q. HAS MR. D'ASCENDIS PROVEN THAT THE RISKS FACED BY HIS NON-REGULATED PROXY GROUP ARE SIMILAR TO THAT OF HIS ELECTRIC UTILITY GROUP?

A. No. The risks faced in each industry for the companies used in Mr. D'Ascendis' unregulated group differ from the risks faced by his electric utility group. Specifically, the level of competition between non-price regulated companies and monopolies, which utilities largely are, is too difficult a factor to control. Although beta is an indicator of a company's investment risk in relation to the entire stock market, beta is not a quantification of the total investment risk of a given company. Mr. D'Ascendis' unregulated proxy group may have a beta comparable to that of his electric group, but that does not mean the companies face sufficiently similar risks to be used as a substitute for an industry's market. Both

[37] Citizens'/Wellsboro Statement No. 2R, pp. 27-30.

beta and the standard error of regression are measures of the past performance of a stock and as such do not necessarily reflect where an industry is going or what risks it is expected to face.

Additionally, the Commission made the following comments in the 2018 UGI Electric case regarding the CE method, specifically, the use of non-utility companies in comparable groups, and stated:

> With respect to the CE method, as noted above, this cost of equity method utilizes data for non-regulated firms. Thus, by its very nature, determining which companies are comparable is entirely subjective. In addition, the record indicates that the companies UGI utilized in its CE group results in the selection of companies such as Coca-Cola Company, Kellogg Company, and Walmart Stores, Inc. . . . Each of these companies operate in industries that are very different from a utility company and have significantly more competition, which would require a higher return for the associated additional risk.[38]

Finally, I am advised by counsel that this premise defies the principle set forth in the *Hope* and *Bluefield* cases that a utility is entitled to a return similar to that being earned by companies with similar risks and uncertainties, but not as high as those earned by highly profitable or speculative ventures.[39]

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[38] *Pa. PUC v. UGI Utilities, Inc. – Electric Division*, Docket No. R-2017-2640058, p. 105 (Order Entered October 25, 2018). The Commission has also ruled "[t]he use of nonregulated companies as a comparable group for regulated firms requires numerous unsupportable assumptions which results in a highly speculative finding." *Pennsylvania Public Utility Commission v. Philadelphia Electric Co.*, 33 PUR 4th 319, 341 (Pa. PUC 1980).

[39] *See Bluefield Water Works & Improvements Co. v. Public Service Comm. of West Virginia,* 262 U.S. 679, 692-93 (U.S. 1923) and *FPC v. Hope Natural Gas Co.,* 320 U.S. 591, 603 (U.S. 1944).

Finally, considering there is a range of 277[40] basis points for his Electric Proxy Group DCF results and a range of 508[41] basis points for his Non-Price Regulated Proxy Group DCF results, overlap is almost inevitable.

SIZE ADJUSTMENT

Q. SUMMARIZE YOUR DIRECT TESTIMONY REGARDING MR. D'ASCENDIS' CLAIM FOR AN ADJUSTMENT FOR THE COMPANIES' SMALL SIZE.

A. In direct testimony, I stated that Mr. D'Ascendis' 85-basis point adjustment is unnecessary because none of the technical literature cited in his direct testimony supporting an adjustment related to the size of a company is specific to the utility industry. Additionally, I stated that any expense impact resulting from the lesser buying power of a smaller utility is reflected in the revenue requirement and the dollar-for-dollar recovery that applies to expenses and to apply an additional size adjustment to a smaller regulated utility would only duplicate the burden to ratepayers. I also presented an article by Dr. Annie Wong that demonstrated there is no need to make an adjustment for the size of a company in utility rate regulation. Finally, I indicated that the Commission has recently rejected the application of a size adjustment to the cost of equity calculation.[42]

[40] Citizens'/Wellsboro Statement No. 2R, p. 30 (10.90% - 8.13% = 2.77%).
[41] Citizens'/Wellsboro Statement No. 2R, p. 30 (12.30% - 7.22% = 5.08%).
[42] I&E Statement No. 2, pp. 44-48.

Q. SUMMARIZE THE COMPANIES' RESPONSE IN REBUTTAL TESTIMONY REGARDING A SIZE RISK FACTOR ADJUSTMENT.

A. Mr. D'Ascendis opines that firms of smaller size are less able to cope with significant events affecting sales, are less diverse in their operations, and have less financial flexibility. He supports these statements by pointing to a Fama and French study relating the size of a company to its return on equity. Mr. D'Ascendis also attempts to discredit a study performed by Dr. Wong, which I&E relied upon in rejection of his size adjustment, by citing a review of her study authored by Thomas M. Zepp. Additionally, Mr. D'Ascendis points to a 2019 Commission order where the Commission considered a size adjustment. Finally, Mr. D'Ascendis calculated the standard deviation of my DCF results.[43]

Additionally, Mr. Johnson points to Citizens' 2019 rate case order where he states that the Commission accepted a size adjustment and should apply a size adjustment in this proceeding for regulatory consistency.[44]

Finally, Mr. Farnsworth states that the Commission should include a size adjustment opining that Wellsboro received a size adjustment in the past and it is used in planning their system improvements and projecting Wellsboro's financial situation.[45]

[43] Citizens'/Wellsboro Statement No. 2R, pp. 8-12.
[44] Citizens' Statement No. 4R, p. 6.
[45] Wellsboro Statement No. 4R, p. 4, lines 1-5.

Q. ARE MR. D'ASCENDIS' ASSERTIONS REGARDING FIRMS OF SMALLER SIZE RELEVANT TO THE REGULATED UTILITY INDUSTRY?

A. No. The study performed by Dr. Wong provides empirical evidence that refutes Mr. D'Ascendis' claim that I will further elaborate upon below.

Q. WHAT ARE YOUR OBSERVATIONS REGARDING THE FAMA AND FRENCH STUDY MR. D'ASCENDIS RELIES ON TO SUPPORT HIS CLAIM OF A SIZE ADJUSTMENT?

A. The Fama and French study is not specific to the utility industry. While I&E relied upon the Fama and French study in this proceeding, as Mr. D'Ascendis correctly points out, the purpose for which I&E cited the study was to empirically demonstrate the shortcomings of the CAPM. The Fama and French study is irrelevant toward the determination of the size risk factor because it is not specific to the utility industry.

Q. PLEASE COMMENT ON THE REVIEW OF DR. WONG'S STUDY PERFORMED BY DR. ZEPP.

A. The article Mr. D'Ascendis references from Dr. Zepp does not recreate Dr. Wong's study; it simply speculates on other possible reasons for her results and references the results of two other studies. The first study, completed by the California Public Utilities Commission Staff in 1991, is not included in the article,

and, therefore, Dr. Zepp's opinions cannot be properly evaluated. Dr. Zepp also draws his conclusions about an entire industry based on the second study, which examines the effects of size on only four water utility companies. This article does not contain enough credible evidence to refute Dr. Wong's findings.

Q. HAVE YOU FOUND FURTHER EVIDENCE TO SUPPORT YOUR RECOMMENDATION REGARDING SIZE ADJUSTMENTS?

A. Yes. The difficulty in predicting the risk effect of a company's size is demonstrated in the variance from year to year of the measurement of difference between the annual returns on the large and small-capitalization stocks of the NYSE/AMEX/NASDAQ in the Ibbotson *Stocks, Bonds, Bills & Inflation: 2015 Yearbook.* As stated on page 100:

> While the largest stocks actually declined in 2001, the smallest stocks rose more than 30%. A more extreme case occurred in the depression-recovery year of 1933, when the difference between the first and 10th decile returns was far more substantial. The divergence in the performance of small- and large- cap stocks is evident. In 30 of the 89 years since 1926, the difference between the total returns of the largest stocks (decile 1) and the smallest stocks (decile 10) has been greater than 25 percentage points.

Page 109 states:

> In four of the last 10 years, large-capitalization stocks (deciles 1-2 of NYSE/AMEX/NASDAQ) have outperformed small-capitalization stocks (deciles 9-10). This has led some market observers to speculate that there is no size premium. But statistical evidence suggests that periods of underperformance should be expected.

Page 112 states:

> Because investors cannot predict when small-cap returns will be higher than large-cap returns, it has been argued that they do not expect higher rates of return for small stocks.

Q. WHAT IS YOUR RESPONSE TO MR. D'ASCENDIS' REBUTTAL TESTIMONY REGARDING THE REFERENCED COMMISSION ORDER FOR CITIZENS'?

A. Although the Commission in the Citizens' 2019 proceeding agreed that there is an inverse relationship between size and risk, the Commission concluded that there is not substantial evidence that size is specifically a risk for utilities as follows:

> At the same time, however, we echo the ALJs that the Parties have presented offsetting arguments such that there is not substantial evidence to determine whether size is specifically a risk for utilities. As I&E and the OCA both noted, the technical literature presented by Citizens' is not specific to the utility industry and also may not definitively support a size adjustment. Additionally, as I&E observed, the empirical study undertaken by the Company's witness Mr. D'Ascendis illustrates the difficulty in predicting the risk effect of a company's size. More specifically, while Mr. D'Ascendis used market information from the NYSE, the AMEX, and the NASDAQ, we find that I&E offered evidence indicating that for certain periods, large-capitalization stocks have outperformed small-capitalization stocks such that there is not sufficient correlation to prove that size is a specific risk for utilities. I&E St. 2-SR at 23-24. Therefore, we are not persuaded by the Company's argument that the ALJs erred by not awarding Citizens' a greater size adjustment. For this reason, we decline to award an explicit 100-basis point size adjustment, as advocated by Citizens'.[46]

[46] *Pa. PUC v. Citizens' Electric Company of Lewisburg, PA*, Docket No. R-2019-3008212 (Order Entered April 29, 2020). *See generally* Disposition of Cost of Common Equity, pp. 103-104.

Finally, as stated in my direct testimony, the Commission has specifically rejected the application of a size adjustment to the cost of equity calculation.[47]

Q. WHAT IS YOUR RESPONSE TO MR. JOHNSON'S REBUTTAL TESTIMONY REGARDING THE REFERENCED COMMISSION ORDER FOR CITIZENS'?

A. The Commission did not, in fact, award an explicit size adjustment as the Commission determined that there was not enough evidence as to whether size is specifically a risk for utilities:

> Consistent with the foregoing discussion, like the ALJs, we shall not specify an exact size adjustment. Instead, we shall adopt the ALJs' recommendation that Citizens' be awarded a DCF cost of common equity of 9.49%. In our view, this cost of equity is reasonable and strikes an appropriate balance by recognizing the general inverse relationship between a company's size and its risk, while acknowledging that there is not substantial evidence in the record to prove that an explicit size basis point adjustment is warranted in this case.[48]

Finally, as I stated above and in my direct testimony, the Commission has rejected the application of a size adjustment to the cost of equity calculation in the 2017 UGI Electric rate case.[49]

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[47] I&E Statement No. 2, p. 46, lines 1-2.

[48] *Pa. PUC v. Citizens' Electric Company of Lewisburg, PA*, Docket No. R-2019-3008212, pp. 103-04 (Order Entered April 29, 2020).

[49] *Pa. PUC v. UGI Utilities, Inc. – Electric Division;* Docket No. R-2017-2640058, p. 100 (Order Entered October 25, 2018).

Q. DO YOU AGREE WITH MR. FARNSWORTH THAT THE COMMISSION'S PAST ISSUANCE OF ADDITIONAL EQUITY POINTS TO RECOGNIZE SIZE MEANS THAT THE COMPANIES SHOULD ALSO RECEIVE AN ADJUSTED RETURN ON EQUITY IN THIS PROCEEDING?

A. No. The issuance of equity points to recognize size should be done on a case-by-case basis.

Q. HAS YOUR RECOMMENDATION REGARDING MR. D'ASCENDIS' SIZE ADJUSTMENT CHANGED SINCE YOUR DIRECT TESTIMONY?

A. No. I continue to recommend that any adjustments in consideration of the Companies' size be disallowed.

PERFORMANCE FACTOR ADJUSTMENT

Q. SUMMARIZE MR. D'ASCENDIS', MR. JOHNSON'S, AND MR. FARNSWORTH'S REBUTTAL TESTIMONY REGARDING A PERFORMANCE FACTOR ADJUSTMENT.

A. Mr. D'Ascendis simply states, "the Companies should each be awarded a five-basis point upward adjustment to their indicated ROE based on Code 66 Pa. C.S. § 523 regarding performance factor."[50] He further states, "[s]imply put, Code 66 Pa.

[50] Citizens'/Wellsboro Statement No. 2R, p. 13, lines 5-6.

C.S. § 523 is in existence to incentivize companies to 'do their job' at a high level. The Companies in this case fulfill the requirement of the statute and should receive the benefit of doing so."[51] He does not offer an explanation beyond what he argued in his direct testimony.

Mr. Johnson states that I ignored the specific examples given that he opines exceed regulatory requirements. Mr. Johnson provides specific examples such as low customer complaints, favorable customer feedback, customer support calls, energizing new service locations, reliability, zero reportable injuries, technology adoptions, pole attachments, tree line designation, and capital investment. Mr. Johnson states that Citizens' agrees that there is no obligation or entitlement for Citizens' to receive a management performance adjustment. Finally, he notes that Citizens' received basis points for management performance in Citizens' 2019 proceeding and should so again for regulatory consistency.[52]

Mr. Farnsworth provides specific examples that he opines is exemplary management performance such as improvements to reliability and resiliency, reduction in customer complaints, implementation of capital projects to improve overall reliability and resilience to Wellsboro's distribution system, reconductoring its three-phase lines, expedited its wood pole replacement program, and installed vacuum reclosers that replaced high maintenance hydraulic reclosers. Additionally, Mr. Farnsworth states that the Commission should

[51] Citizens'/Wellsboro Statement No. 2R, p. 13, lines 11-13.
[52] Citizens' Statement No. 4R, pp. 2-5.

include a performance factor adjustment opining that Wellsboro received a performance factor adjustment in the past and that Wellsboro relies on receiving consistent treatment by the Commission as it is used in planning system improvements and projecting Wellsboro's financial situation.[53]

Q. WHAT IS YOUR RESPONSE TO MR. D'ASCENDIS', MR. JOHNSON'S, AND MR. FARNSWORTH'S REBUTTAL TESTIMONY REGARDING MANAGEMENT PERFORMANCE?

A. My position remains unchanged from the arguments made in my direct testimony. Awarding the Companies management effectiveness points would add an increased cost to ratepayers for service. Any savings from effective operating and maintenance cost measures should flow through to ratepayers and investors. These claimed savings would likely be offset by the addition of basis points for management effectiveness as ratepayers would have to fund the additional costs. This defeats the purpose of implementing cost saving measures to benefit ratepayers.

Additionally, the Companies should not be awarded management performance points in order to provide a sufficient return on equity or to affect investment decisions and planning for future financial activities, including the timing of rate cases. The purpose of base rate cases is to allow a utility to recover

[53] Wellsboro Statement No. 4R, p. 2-4.

its costs and provide it the *opportunity* to earn a reasonable return on capital investments where additional basis points for management performance would not be necessary if management was as effective as they claim.

The Companies should also not be rewarded for management performance for not utilizing the Distribution System Improvement Charge (DSIC) when it replaced its mains. The Commission offers risk reducing mechanisms such as the DSIC and the FPFTY to help reduce any regulatory lag in recovery of infrastructure investment or other unforeseen expenditures, however, the DSIC and the use of a FPFTY were not designed to eliminate the need for periodic base rate filings. The DSIC was specifically designed to encourage its use and to incentivize accelerated pipeline replacement and infrastructure upgrades to bring the existing aging infrastructure closer to meeting safety and reliability requirements in between base rate filings. It is irrational to wait until after the fact to hopefully receive additional basis points on its return on equity for management performance.

Furthermore, past issuance of additional equity points for management performance in prior proceedings as stated by Mr. Farnsworth does not guarantee such issuance in future proceedings. The issuance of equity points to recognize management performance should be done on a case-by-case basis. Additionally, this idea presented by Mr. Farnsworth contradicts Citizens' witness Johnson who

states that Citizens' agrees that there is no obligation or entitlement for Citizens' to receive a management performance adjustment.[54]

Finally, as discussed in my direct testimony, true management effectiveness is earning a higher return through efficient use of resources and cost cutting measures. The greater net income resulting from cost savings and true efficiency in management and operations is available to be passed on to shareholders. The Companies, or any utility, should not be awarded additional basis points for doing what they are required to do in order to provide adequate, efficient, safe, and reasonable service.[55]

OVERALL RATE OF RETURN

Q. HAS YOUR OVERALL RATE OF RETURN RECOMMENDATION FOR THE COMPANIES CHANGED FROM YOUR DIRECT TESTIMONY?

A. No. I continue to support each recommendation made in I&E Statement No. 2.

Q. WHAT IS YOUR OVERALL RATE OF RETURN RECOMMENDATION?

A. I recommend the following rate of return for the Companies:

[54] Citizens' Statement No. 4R, p. 2, line 20 through p. 3, line 1.
[55] *See* 66 Pa. C.S. § 1501.

Summary of Cost of Capital			
Type of Capital	**Ratio**	**Cost Rate**	**Weighted Cost**
Citizens' Electric Company of Lewisburg			
Long-Term Debt	51.06%	5.47%	2.79%
Common Equity	48.94%	10.78%	5.28%
Total	100.00%		8.07%

Summary of Cost of Capital			
Type of Capital	**Ratio**	**Cost Rate**	**Weighted Cost**
Wellsboro Electric Company			
Long-Term Debt	51.06%	4.85%	2.48%
Common Equity	48.94%	10.78%	5.28%
Total	100.00%		7.76%

Q. DOES THIS CONCLUDE YOUR SURREBUTTAL TESTIMONY?

A. Yes.

I&E Statement No. 3
Witness: Ethan H. Cline

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

WELLSBORO ELECTRIC COMPANY

Docket No. R-2025-3054392

Direct Testimony

Of

Ethan H. Cline

Bureau of Investigation and Enforcement

Concerning:

Rate Base
Customer Cost Analysis
Scale Back of Rates

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INTRODUCTION

Q. WOULD YOU PLEASE STATE YOUR NAME AND BUSINESS ADDRESS?

A. My name is Ethan H. Cline. My business address is Pennsylvania Public Utility Commission, Commonwealth Keystone Building, 400 North Street, Harrisburg, Pennsylvania 17120.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed as a Fixed Utility Valuation Engineer in the Pennsylvania Public Utility Commission's ("Commission") Bureau of Investigation and Enforcement ("I&E").

Q. WHAT IS YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND?

A. My education and professional background are set forth in Appendix A, which is attached.

Q. PLEASE DESCRIBE THE ROLE OF I&E IN RATE PROCEEDINGS.

A. I&E is responsible for protecting the public interest in proceedings before the Commission. The I&E analysis in this proceeding is based on its responsibility to represent the public interest. This responsibility requires the balancing of the interests of ratepayers, the regulated utility, and the regulated community as a

whole.

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. The purpose of my direct testimony is to present recommendations regarding Wellsboro Electric Company ("Wellsboro" or "Company") request for a base rate revenue increase of $2,899,388[1]. I will address issues including rate base, cost of service study, and rate structure.

TEST YEAR

Q. WHAT TEST YEARS HAS THE COMPANY USED IN THIS PROCEEDING?

A. Wellsboro has selected the year ended December 31, 2024, as the historic test year ("HTY"), the year ending December 31, 2025, as the future test year ("FTY"), and the year ending December 31, 2026, as the fully projected future test year ("FPFTY")[2].

Q. WHAT TEST YEAR HAS THE COMPANY BASED ITS REVENUE REQUIREMENT ON IN THIS PROCEEDING?

A. Wellsboro based its requested revenue requirement on the FPFTY ending December 31, 2026.[3]

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1 Wellsboro Exhibit HSG-1, Schedule C1.
2 Wellsboro Statement No. 1, p. 2.
3 *Id.*

RATE BASE

Q. WHAT IS RATE BASE?

A. Rate base is the depreciated original cost of a utility's investment in plant a utility has in place to serve customers plus other additions and deductions that the Commission determines to be necessary in order to keep the utility operating and providing safe and reliable service to its customers.

Q. HOW IS RATE BASE USED WITHIN THE RATEMAKING FORMULA?

A. Rate base is one part of the financial equation used by the Commission to determine the appropriate revenue that a utility is granted in a rate proceeding. The revenue determination allows the utility to meet its expense obligations and gives it the opportunity to earn the rate of return established by the Commission in a rate proceeding. The equation used to determine the proper revenue requirement level is:

Revenue Requirement = (Rate Base x Rate of Return) + Operating Expenses + Depreciation Expenses + Taxes.

CUSTOMER DESPOSTIS

Q. WHAT RATE BASE IS THE COMPANY CLAIMING FOR THE FPFTY ENDING DECEMBER 31, 2026?

A. The Company's claimed rate base for the FPFTY ending December 31, 2026, is

$25,857,280.[4]

Q. HAS THE COMPANY STATED ITS INTENTION TO ADJUST ITS RATE BASE CLAIM IN REBUTTAL TESTIMONY?

A. Yes. In its response to I&E-RB-8, the Company stated its intent to reflect in its rebuttal testimony an update to its claim for Customer Deposits in the FPFTY rate base claim.[5] The updated claim is based on the 13-month average of actual claims ended December 31, 2024, rather than the asset balance at December 31, 2024, as filed.

Q. WHAT IS THE COMPANY'S PROPOSED CHANGE TO ITS CUSTOMER DEPOSITS CLAIM?

A. The Company will update its customer deposits claim by decreasing the claim by $80,450 from $195,713 to $115,263.[6]

Q. WHAT IS THE TOTAL UPDATE TO RATE BASE THAT THE COMPANY INDICATED IT WILL PROPOSE?

A. As shown on I&E Exhibit No. 3, Schedule 2, line 10, the Company's updates will result in an increase to the Company's as filed rate base claim of $80,450 from $25,857,280 to $25,937,730.

[4] Wellsboro Exhibit_(HSG-1), Schedule C1-5, line 13.
[5] Company responses to I&E-RB-8 attached as I&E-Exhibit No. 3, Schedule 1.
[6] *Id*.

Q. DO YOU AGREE WITH THE COMPANY'S UPDATED CUSTOMER DEPOSITS AND RATE BASE CLAIMS BASED ON ACTUAL 13-MONTH AVERAGE BALANCES?

A. Partially. While I do agree that using a 13-month average of actual monthly balances is the proper methodology to customer deposits claims in the FPFTY, I do not agree that the Company used the correct time period in projecting these claims. Specifically, I recommend the customer deposits claims be based on a 13-month average of the most recent actual balances available.

Q. WHAT IS THE CUSTOMER DEPOSITS AMOUNT BASED ON THE MOST RECENT 13-MONTH AVERAGE OF ACTUAL CLAIMS?

A. The result of calculating the customer deposits amount by using the most recent 13-month average of actual balances available is $120,033.[7] This is an increase of $4,769[8] from the Company's updated customer deposits claim of $115,263 to $120,033.[9] Because customer deposits is a net reduction to rate base, the increase to the customer deposits claim represents a reduction to rate base of the same amount.

[7] I&E Exhibit No. 3, Schedule 3.
[8] The $1 mathematical error in this calculation is due to rounding.
[9] I&E Exhibit No. 3, Schedule 2, line 5, columns C-E.

Q. WHY DO YOU RECOMMEND THE PROJECTED CUSTOMER DEPOSITS CLAIMS BE BASED UPON A 13-MONTH AVERAGE OF THE MOST RECENT ACTUAL BALANCES AVAILABLE?

A. Basing the FPFTY projection of customer deposits on the most recent data available is reasonable because it provides a more accurate and reasonable projection for the FPFTY.

Q. IF THE COMPANY PROVIDES FURTHER UPDATES THROUGH THE COURSE OF THIS PROCEEDING, SHOULD THE CUSTOMER DEPOSITS CLAIMS BE ADJUSTED?

A. Yes. It is appropriate to use the most recent 13-month average available to determine the customer deposits balances.

MATERIALS AND SUPPLIES

Q. WHAT IS THE COMPANY'S CLAIM FOR MATERIALS AND SUPPLIES?

A. The Company claimed $247,983 for Materials and Supplies. The Company's claim for materials and supplies is simply the asset amount at December 31, 2024.[10]

[10] Wellsboro response to I&E-RB-1, attached as I&E Exhibit No. 3 Schedule 4.

Q. DO YOU AGREE WITH THE COMPANY'S CLAIM FOR MATERIALS AND SUPPLIES?

A. No. As with its customer deposits claim, described above, the materials and supplies claim in the FPFTY should be determined through a 13-month average of the most recent actual materials and supplies balances available.

Q. WHAT DO YOU RECOMMEND REGARDING THE CLAIM FOR MATERIALS AND SUPPLIES?

A. I recommend that Wellsboro's materials and supplies claim be increased by $54,313 from $247,983 to $302,296.[11]

Q. HOW DID YOU DETERMINE THE $302,296 MATERIALS AND SUPPLIES AMOUNT?

A. In its response to I&E-RB-1, the Company provided a list of month end materials and supplies balances from January 2023 through the most recent month available, or April 2025.[12] I&E Exhibit No. 3, Schedule 5 shows the calculation of the 13-month average of materials and supplies based on the most recent 13-months of actual data available.

[11] I&E Exhibit No. 3, Schedule 2, line 7.
[12] I&E Exhibit No. 3, Schedule 4.

Q. WHAT TOTAL ADJUSTMENT TO RATE BASE DO YOU RECOMMEND?

A. As a result of my recommended adjustments to customer deposits and materials and supplies, I am recommending an increase to the Company's total, as filed, rate base of $129,993 from $25,857,280 to $25,987,273.[13]

CUSTOMER COST ANALYSIS

Q. WHAT IS A CUSTOMER COST ANALYSIS AND HOW IS IT USED?

A. A customer cost analysis is part of a cost of service study that includes only customer costs to determine the appropriate customer charges for the various classes.

Q. WHAT IS WELLSBORO PROPOSING REGARDING CUSTOMER CHARGES?

A. Wellsboro is proposing to increase the customer charge of each rate class as shown on Wellsboro Exhibit_(HSG-1), Schedule B7 and summarized below:

Customer Charges			
Rate Class	Present Rate	Proposed Rate	Percent Increase
RS and RSAE	$12.00	$16.50	37.5%
NRS and NRH	$12.22	$16.50	35.0%
CS	$32.03	$32.03	0.0%
CSH	$45.81	$45.81	0.0%
IS	$85.00	$150.00	76.5%

[13] I&E Exhibit No. 3, Schedule 2, line 10.

Q. ARE THE COMPANY'S PROPOSED CUSTOMER CHARGES CONSISTENT WITH ITS CUSTOMER COST ANALYSIS?

A. Partially. The following table, which is a comparison of the Company's proposed customer charges and the results of the customer cost analysis depicted on Wellsboro Exhibit_(HSG-1), Sch. E-1C, shows that the RS, RSAE, NRS, and NRH rate classes include proposed rates consistent with the customer cost analysis and the CS and CSH are not proposed customer charge increases because their present rates are currently above the results of the customer cost analysis. However, the Company is proposing a significant increase to the IS rate class customer charge despite the present rates are above the results of the customer cost analysis.

Customer Charges			
Rate Class	Present Rate	Proposed Rate	Customer Cost Analysis
RS and RSAE	$12.00	$16.50	$17.59
NRS and NRH	$12.22	$16.50	$17.59
CS	$32.03	$32.03	$26.35
CSH	$45.81	$45.81	$26.35
IS	$85.00	$150.00	$71.80

Q. ARE YOU RECOMMENDING AN ADJUSTMENT TO THE PROPOSED IS CLASS CUSTOMER CHARGE?

A. No. While the customer cost analysis shows that the IS class customer charge should not be above $71.80, the IS class generally consists of larger users where a

higher customer charge and lower usage rate could be beneficial. Therefore, I recommend that the IS class customer charge be included in a scale back of rates as discussed below.

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE APPROPRIATE LEVEL OF CUSTOMER CHARGES FOR EACH CLASS?

A. As described below, I recommend that the increase in the customers charges that are proposed an increase be scaled back if the Commission grants an increase less than the full increase.

SCALE BACK OF RATES

Q. WHAT DO YOU RECOMMEND IF THE COMMISSION GRANTS LESS THAN THE FULL INCREASE?

A. If the Commission grants less than the Company's requested increase, I recommend that the proposed increase be scaled back based on the cost of service study ultimately approved by the Commission. As I stated above, I also recommend that the customer charges that have a proposed increase be included in any scale back of rates.

Q. WHY DO YOU RECOMMEND THE CUSTOMER CHARGES THAT HAVE BEEN PROPOSED AN INCREASE BE INCLUDED IN A SCALE BACK OF RATES?

A. Despite the RS, RSAE, NRS, and NRH customer charges being supported by the customer cost analysis, as discussed above, the increases to each charge represent significant increases to the fixed portion of the customer's bill of 37.5% for the RS and RSAE classes and 35.0% for the NRS and NRH, classes, as shown above. Therefore, it is reasonable to include these rates in any scale back of rates. Furthermore, if a lower increase is authorized, it is reasonable to expect that the lower revenue authorization would be related to accepted expense and return adjustments that would likely impact the outcome of the customer cost analysis, so including a scale back of customer charges is a logical approach in this scenario.

Q. DID THE COMMISSION DETERMINE IN A RECENT ELECTRIC RATE CASE THAT IT WAS PREFERABLE TO SCALE BACK THE CUSTOMER CHARGES EVEN IF THE CUSTOMER COST ANALYSIS SUPPORTS THE FULL INCREASE?

A. Yes. In the UGI Utilities, Inc. – Electric Division rate case at Docket No. R-2017-2640058, the Commission determined that despite the higher customer cost determination in the cost of service study, the customer charges should be reduced for all customers[14]. My recommendation is consistent with the Commission's

[14] *Pa. PUC v. UGI Utilities, Inc. – Electric Division*, R-2017-2640058, p. 175 (Order Entered October 25, 2018).

decision in this Order.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

ETHAN H. CLINE
PROFESSIONAL EXPERIENCE AND EDUCATION

EXPERIENCE:

03/2009 - Present

Bureau of Investigation and Enforcement, Pennsylvania Public Utility Commission - Harrisburg, Pennsylvania

Fixed Utility Valuation Engineer – Assists in the performance of studies and analyses of the engineering-related areas including valuation, depreciation, cost of service, quality and reliability of service as they apply to fixed utilities. Assists in reviewing, comparing and performing analyses in specific areas of valuation engineering and rate structure including valuation concepts, original cost, rate base, fixed capital costs, inventory processing, excess capacity, cost of service, and rate design.

06/2008 – 09/2008

Akens Engineering, Inc. - Shiremanstown, Pennsylvania

Civil Engineer – Responsible, primarily, for assisting engineers and surveyors in the planning and design of residential development projects

10/2007 – 05/2008

J. Michael Brill and Associates - Mechanicsburg, Pennsylvania

Design Technician – Responsible, primarily, for assisting engineers in the permit application process for commercial development projects.

01/2006 – 10/2007

CABE Associates, Inc. - Dover, Delaware

Civil Engineer – Responsible, primarily, for assisting engineers in performing technical reviews of the sewer and sanitary sewer systems of Sussex County, Delaware residential development projects.

EDUCATION:

Pennsylvania State University, State College, Pennsylvania
Bachelor of Science; Major in Civil Engineering, 2005

- Attended NARUC Rate School, Clearwater, FL

TESTIMONY SUBMITTED:

I have testified and/or submitted testimony in the following proceedings:

1. Clean Treatment Sewage Company, Docket No. R-2009-2121928
2. Pennsylvania Utility Company – Water Division, Docket No. R-2009-2103937
3. Pennsylvania Utility Company – Sewer Division, Docket No. R-2009-2103980
4. UGI Central Penn Gas, Inc., 1307(f) proceeding, Docket No. R-2010-2172922
5. PAWC Clarion Wastewater Operations, Docket No. R-2010-2166208
6. PAWC Claysville Wastewater Operations, Docket No. R-2010-2166210
7. Citizens' Electric Company of Lewisburg, Pa, Docket No. R-2010-2172665
8. City of Lancaster – Bureau of Water, Docket No. R-2010-2179103
9. Peoples Natural Gas Company LLC, Docket No. R-2010-2201702
10. UGI Central Penn Gas, Inc., Docket No. R-2010-2214415
11. Pennsylvania-American Water Company, Docket No. R-2011-2232243
12. Pentex Pipeline Company, Docket No. A-2011-2230314
13. Peregrine Keystone Gas Pipeline, LLC, Docket No. A-2010-2200201
14. Philadelphia Gas Works 1307(f), Docket No. R-2012-2286447
15. Peoples Natural Gas Company LLC, Docket No. R-2012-2285985
16. Equitable Gas Company, Docket Nos. R-2012-2312577, G-2012-2312597
17. City of Lancaster – Sewer Fund, Docket No. R-2012-2310366
18. Peoples TWP, LLC 1307(f), Docket No. R-2013-2341604
19. UGI Penn Natural Gas, Inc. 1307(f), Docket No. R-2013-2361763
20. UGI Central Penn Gas, Inc. 1307(f), Docket No. R-2013-2361764
21. Joint Application, Docket Nos. A-2013-2353647, A-2013-2353649, A-2013-2353651
22. City of Dubois – Bureau of Water, Docket No. R-2013-2350509
23. The Columbia Water Company, Docket No. R-2013-2360798
24. Pennsylvania American Water Company, Docket No. R-2013-2355276
25. Generic Investigation Regarding Gas-on-Gas Competition, Docket Nos. P-2011-227868, I-2012-2320323
26. Philadelphia Gas Works 1307(f), Docket No. R-2014-2404355
27. Pike County Light and Power Company (Gas), Docket No. R-2013-2397353
28. Pike County Light and Power Company (Electric), Docket No. R-2013-2397237
29. Peoples Natural Gas Company LLC 1307(f), Docket No. R-2014-2403939
30. UGI Penn Natural Gas, Inc. 1307(f), Docket No. R-2014-2420273
31. UGI Utilities, Inc. – Gas Division 1307(f), Docket No. R-2014-2420276
32. UGI Central Penn Gas, Inc. 1307(f), Docket No. R-2014-2420279
33. Emporium Water Company, Docket No. R-2014-2402324
34. Borough of Hanover – Hanover Municipal Water, Docket No. R-2014-2428304
35. Philadelphia Gas Works 1307(f), Docket No. R-2015-2465656
36. Peoples Natural Gas Company LLC 1307(f), Docket No. R-2015-2465172

37. Peoples Natural Gas Company – Equitable Division 1307(f), Docket No. R-2015-2465181
38. PPL Electric Utilities Corporation, Docket No. R-2015-2469275
39. UGI Penn Natural Gas, Inc. 1307(f), Docket No. R-2015-2480934
40. UGI Central Penn Gas, Inc. 1307(f), Docket No. R-2015-2480937
41. UGI Utilities, Inc. – Gas Division 1307(f), Docket No. R-2015-2480950
42. UGI Utilities, Inc. – Gas Division, Docket No. R-2015-2518438
43. Joint Application of Pennsylvania American Water, et al., Docket No. A-2016-2537209
44. UGI Utilities, Inc. – Gas Division 1307(f), Docket No. R-2016-2543309
45. UGI Central Penn Gas, Inc. 1307(f), Docket No. R-2016-2543311
46. City of Dubois – Company, Docket No. R-2016-2554150
47. UGI Penn Natural Gas, Inc., Docket No. R-2016-2580030
48. UGI Central Penn Gas, Inc. 1307(f), Docket No. R-2017-2602627
49. UGI Penn Natural Gas, Inc. 1307(f), Docket No. R-2017-2602633
50. UGI Utilities, Inc. – Gas Division 1307(f), Docket No. R-2017-2602638
51. Application of Pennsylvania American Water Company Acquisition of the Municipal Authority of the City of McKeesport, Docket No. A-2017-2606103
52. Pennsylvania American Water Company, Docket No. R-2017-2595853
53. Pennsylvania American Water Company Lead Line Petition, Docket No. P-2017-2606100
54. UGI Utilities, Inc. – Electric Division, Docket No. R-2017-2640058
55. Peoples Natural Gas Company, LLC – Peoples and Equitable Division 1307(f), Docket Nos. R-2018-2645278 & R-2018-3000236
56. Peoples Gas Company, LLC 1307(f), Docket No. R-2018-2645296
57. Columbia Gas of Pennsylvania, Inc., Docket No. R-2018-2647577
58. Duquesne Light Company, Docket No. R-2018-3000124
59. Suez Water Pennsylvania, Inc., Docket No. R-2018-3000834
60. Application of Pennsylvania American Water Company Acquisition of the Municipal Authority of the Township of Sadsbury, Docket No. A-2018-3002437
61. The York Water Company, Docket No. R-2018-3000006
62. Application of SUEZ Water Pennsylvania, Inc. Acquisition of the Water and Wastewater Assets of Mahoning Township, Docket Nos. A-2018-3003517 and A-2018-3003519
63. Pittsburgh Water and Sewer Authority, Docket Nos. R-2018-3002645 and R-2018-3002647
64. Joint Application of Aqua America, Inc. et al., Acquisition of Peoples Natural Gas Company LLC, et al., Docket Nos. A-2018-3006061, A-2018-3006062, and A-2018-3006063
65. Implementation of Chapter 32 of the Public Utility Code Regarding Pittsburgh Water and Sewer Authority, Docket Nos. M-2018-2640802 and M-2018-2640803
66. Philadelphia Gas Works 1307(f), Docket No. R-2019-3007636
67. People Natural Gas Company, LLC, Docket No. R-2018-3006818

68. Application of Pennsylvania American Water Company Acquisition of the Steelton Borough Authority, Docket No. A-2019-3006880
69. Application of Aqua America, Inc. et al., Acquisition of the Wastewater System Assets of the Township of Cheltenham, Docket No. A-2019-3006880
70. Philadelphia Gas Works, Docket No. R-2019-3009016
71. Wellsboro Electric Company, Docket No. R-2019-3008208
72. Valley Energy, Inc., Docket No. R-2019-3008209
73. Citizens' Electric Company of Lewisburg, Pa, Docket Non. R-2019-3008212
74. Application of Aqua America, Inc. et al., Acquisition of the Wastewater System Assets of the East Norriton Township, Docket No. A-2019-3009052
75. Peoples Natural Gas Company, LLC 1307(f), Docket No. R-2020-3017850
76. Peoples Gas Company, LLC 1307(f), Docket No. R-2020-3017846
77. Philadelphia Gas Works, Docket No. R-2020-3017206
78. Pittsburgh Water and Sewer Authority, Docket Nos. R-2020-3017951 et al.
79. Columbia Gas of Pennsylvania, Docket No. R-2020-3018835
80. Pennsylvania America Water Company, Docket Nos. R-2020-3019369 and R-2020-3019371
81. PECO Energy Company – Gas Division, Docket No. R-2020-3019829
82. PGW 1307(f), Docket No. R-2021-3023970
83. Peoples Natural Gas Company, LLC 1307(f), Docket No. R-2021-3023965
84. Peoples Gas Company, LLC 1307(f), Docket No. R-2021-3023967
85. UGI Utilities, Inc. – Electric Division, Docket No. R-2021-3023618
86. Columbia Gas of Pennsylvania, Inc., Docket No. R-2021-3024926
87. Duquesne Light Company, Docket No. R-2021-3024750
88. UGI Utilities, Inc. – Gas Division 1307(f), Docket No. R-2021-3025652
89. Pittsburgh Water and Sewer Authority, Docket Nos. R-2021-3024773 et al.
90. Application of Aqua America Wastewater, Inc. et al., Acquisition of the Wastewater System Assets of Lower Makefield Township, Docket No. A-2021-3024267
91. Aqua Pennsylvania Water, Inc. and Aqua Pennsylvania Wastewater, Inc., Docket Nos. R-2021-3027385 and R-2021-3027386
92. Application of Pennsylvania-American Water Company for Acquisition of the Wastewater Collection and Treatment System Assets of the York City Sewer Authority, Docket No. A-2021-3024681
93. City of Lancaster – Bureau of Water, Docket No. R-2021-3026682
94. Application of Aqua America Wastewater, Inc. et al., Acquisition of the Wastewater System Assets of East Whiteland Township, Docket No. A-2021-30246132
95. UGI Utilities, Inc. – Gas Division, Docket No. R-2021-3030218
96. Peoples Natural Gas Company, LLC 1307(f), Docket No. R-2022-3030661
97. Columbia Gas of Pennsylvania, Inc., Docket No. R-2022-3031211
98. UGI Utilities, Inc. – Gas Division 1307(f), Docket No. R-2022-3032242

99. Pennsylvania American Water Company, Docket Nos. R-2022-3031672 and R-2022-3031673
100. The York Water Company, Docket Nos. R-2022-3031340 and R-2022-3032806
101. Columbia Gas of Pennsylvania, Inc., Docket No. R-2022-3032167
102. National Fuel Gas Distribution Corporation, Docket No. R-2022-3035730
103. UGI Utilities, Inc. – Electric Division, Docket No. R-2022-3037368
104. Application of Pennsylvania-American Water Company for Acquisition of the Wastewater Collection and Treatment System Assets of the Butler Area Sewer Authority, Docket No. A-2022-3037047
105. Philadelphia Gas Works, Docket No. R-2023-3037933
106. Pittsburgh Water and Sewer Authority, Docket Nos. R-2023-3039920 et al.
107. Pennsylvania-American Water Company, Docket Nos. R-2023-3043189 and R-2023-3043190
108. Peoples Natural Gas Company, LLC, Docket No. R-2023-3044549
109. Duquesne Light Company, Docket No. R-2024-3046523
110. PECO Energy Company – Gas Division, Docket No. R-2024-3046932
111. Aqua Pennsylvania Water, Inc. and Aqua Pennsylvania Wastewater, Inc., Docket Nos. R-2024-3047822 and R-2024-3047824
112. Application of Aqua America Wastewater, Inc. et al., Acquisition of the Wastewater System Assets of Beaver Falls, Docket No. A-202-3033138
113. Pike County Light and Power Company (Gas), Docket No. R-2024-3052357
114. UGI Utilities, Inc. – Gas Division, Docket No. R-2024-3052716
115. Philadelphia Gas Works, Docket No. R-2025-3053112

I&E Exhibit No. 3
Witness: Ethan H. Cline

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

WELLSBORO ELECTRIC COMPANY

Docket No. R-2025-3054392

Exhibit to Accompany

the

Direct Testimony

Of

Ethan H. Cline
Bureau of Investigation and Enforcement

Concerning:

Rate Base
Customer Cost Analysis
Scale Back of Rates

WELLSBORO ELECTRIC COMPANY
DOCKET NO. R-2025-3054392

I&E-RB-8

Reference Wellsboro Electric Exhibit HSG-1, Schedule C2. Regarding the Company's claim for customer deposits in the amount of $195,713, provide the following:

A. A detailed explanation of the method used to develop the claim for customer deposits.

B. Provide the actual balance for each month from January 2023 through the latest month available.

Response Provided By:
Howard Gorman, President, HSG Group, Inc.
Jill L. Campbell, VP of Finance of Administration, Wellsboro Electric Company

Date: June 13, 2025

Response:

A. The Company's claim for Customer deposits, which is an amount that reduces the Company's rate base, is equal to the liability on the Company's balance sheet at December 31, 2024.

The liability on the financial statements includes credit balances in Customer accounts receivable; for rate case purposes, credit balances in Customer accounts receivable should be offset against Customer accounts receivable and not reflected in Customer deposits.

As noted in the response to part B below, the actual balance of Customer deposits at December 31, 2024 was $121,200 and the 13-month average was $115,263; the Company will correct its filing in Rebuttal to reflect the 13-month average.

WELLSBORO ELECTRIC COMPANY
DOCKET NO. R-2025-3054392

B.

		Customer Meter Deposits		
		Account #235.00		
		2023	2024	2025
January		101,425	106,325	121,450
February		98,925	115,225	120,225
Amcrh		100,050	113,125	120,625
April		101,000	113,650	124,750
May		101,900	114,800	125,650
June		101,325	115,275	
July		100,125	116,025	
August		98,725	119,075	
September		99,675	119,950	
October		101,050	120,100	
November		102,375	121,300	
December		102,375	121,200	
Prior December			102,375	
13-month Average			115,263	

Wellsboro Electric Company
FPFTY Rate Base 2026
R-2025-3054392

Line No.		FPFTY 2026 As Filed (A)	Company Adjustment (B)	Company Updated (C)	I&E Adjustment (D)	I&E Adjusted (E)
	Utility Plant in Service					
1	Assets	$ 44,666,856	$ -	$ 44,666,856	$ -	$ 44,666,856
2	Less: Accumulated Depreciation	$ (19,321,064)	$ -	$ (19,321,064)	$ -	$ (19,321,064)
3		$ 25,345,792	$ -	$ 25,345,792	$ -	$ 25,345,792
4	Less: Accumulated Defeerred Income Taxes	$ (38,728)	$ -	$ (38,728)	$ -	$ (38,728)
5	Less: Customer Deposits	$ (195,713)	$ 80,450	$ (115,263)	$ (4,769)	$ (120,033)
6	Accrued Pension / OPEB Liability	$ (19,798)	$ -	$ (19,798)	$ -	$ (19,798)
7	Materials and Supplies	$ 247,983	$ -	$ 247,983	$ 54,313	$ 302,296
8		$ 25,339,536	$ 80,450	$ 25,419,986	$ 49,544	$ 25,469,529
9	Cash Working Capital Allowance	$ 517,744	$ -	$ 517,744	$ -	$ 517,744
10	RATE BASE	$ 25,857,280	$ 80,450	$ 25,937,730	$ 49,544	$ 25,987,273
11	I&E Rate Base adjustment from As Filed:	$ 129,993				

I&E Exhibit No. 3
Schedule 2

Wellsboro Electric Company
Customer Deposits
R-2025-3054392

	Customer Deposits Acct #235		
	2023	2024	2025
January	101,425	106,325	121,450
February	98,925	115,225	120,225
March	100,050	113,125	120,625
April	101,000	113,650	124,750
May	101,900	114,800	125,650
June	101,325	115,275	
July	100,125	116,025	
August	98,725	119,075	
September	99,675	119,950	
October	101,050	120,100	
November	102,375	121,300	
December	102,375	121,200	
December		*102,375*	
Company 13-month Average		115,263	
I&E 13-month Average			120,033

WELLSBORO ELECTRIC COMPANY
DOCKET NO. R-2025-3054392

I&E-RB-1

Reference Wellsboro Electric Exhibit HSG-1, Schedule C2. Regarding the Company's claim for Materials and Supplies in the amount of $247,983, provide the following:

A. A detailed explanation of the method of inventory valuation used to develop the claim for materials and supplies.

B. Provide the actual balance for each month from January 2023 through the latest month available.

Response Provided By:
Howard Gorman, President, HSG Group, Inc.
Jill L. Campbell, VP of Finance of Administration, Wellsboro Electric Company

Date: June 13, 2025

Response:

A. The Company's claim for Materials and Supplies is the asset on the Company's balance sheet at December 31, 2024.

B.

Month End Inventory Balance		
Accounts 154.00-154.99		
2023	**2024**	**2025**
483,953.24	338,593.38	259,767.82
471,035.58	345,523.07	258,576.76
433,127.85	379,202.37	257,289.71
508,043.40	374,605.77	245,758.91
505,761.75	396,560.96	
456,734.77	386,204.78	
455,120.12	339,285.67	
416,185.30	336,456.74	
397,429.81	294,275.87	
355,645.25	277,487.82	
327,930.68	255,595.73	
334,040.67	247,983.12	

Wellsboro Electric Company
Materials and Supplies
R-2025-3054392

	Materials and Supplies Acct #154		
	2023	2024	2025
January	486,953.24	338,593.38	259,767.82
February	471,035.58	345,523.07	258,576.76
March	433,127.85	379,202.37	257,289.71
April	508,043.40	374,605.77	245,758.91
May	505,761.75	396,560.96	
June	456,734.77	386,204.78	
July	455,120.12	339,285.67	
August	416,185.30	336,456.74	
September	397,429.81	294,275.87	
October	355,645.25	277,487.82	
November	327,930.68	255,595.73	
December	334,040.67	247,983.12	
I&E 13-month Average			302,296

I&E Statement No. 3-SR
Witness: Ethan H. Cline

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

WELLSBORO ELECTRIC COMPANY

Docket No. R-2025-3054392

Surrebuttal Testimony

Of

Ethan H. Cline

Bureau of Investigation and Enforcement

Concerning:

Rate Base
Customer Cost Analysis
Scale Back of Rates

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CUSTOMER DESPOSTIS AND MATERIALS AND SUPPLIES **2**

CUSTOMER COST ANALYSIS **2**

CUSTOMER CHARGE SCALE BACK **3**

SCALE BACK OF RATES **6**

INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Ethan H. Cline, and my business address is Pennsylvania Public Utility Commission, Commonwealth Keystone Building, 400 North Street, Harrisburg, PA 17120.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by the Pennsylvania Public Utility Commission (Commission) in the Bureau of Investigation and Enforcement (I&E) as a Fixed Utility Valuation Engineer.

Q. ARE YOU THE SAME ETHAN H. CLINE THAT SUBMITTED DIRECT TESTIMONY ON JULY 15, 2025?

A. Yes. I submitted I&E Statement No. 3 and I&E Exhibit No. 3 on July 15, 2025.

Q. WHAT IS THE PURPOSE OF YOUR SURREBUTTAL TESTIMONY?

A. The purpose of my surrebuttal testimony is to address the rebuttal testimony of Wellsboro Electric Company (Wellsboro or Company) witness Howard S. Gorman.[1] I will also address the rebuttal testimony of the Office of Consumer Advocate (OCA) witness Michael Deupree.[2]

[1] Wellsboro Statement No. 1R.
[2] OCA Statement No. 3R.

Q. DOES YOUR TESTIMONY INCLUDE AN EXHIBIT?

A. No.

CUSTOMER DESPOSITS AND MATERIALS AND SUPPLIES

Q. WHAT DID YOU RECOMMEND REGARDING THE COMPANY'S CUSTOMER DEPOSITS AND MATERIALS AND SUPPLIES CLAIMS?

A. I recommended that the customer deposits and materials and supplies claims be calculated based on the most recent 13-month average of actual balances.[3]

Q. DID THE COMPANY RESPOND TO YOUR RECOMMENDATIONS?

A. Yes. The Company agreed with my recommendation and updated its claims in rebuttal testimony.[4]

CUSTOMER COST ANALYSIS

Q. DID YOU RECOMMEND ANY CHANGES TO THE COMPANY'S CUSTOMER COST ANALYSIS?

A. No. I based my analysis of the Company's proposed customer charges on the customer cost analysis presented in the filing.[5]

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3 I&E Statement No. 3, pp. 3-7.
4 Wellsboro Statement No. 1R, p. 6.
5 I&E Statement No. 3, pp. 8-10.

CUSTOMER CHARGE SCALE BACK

Q. WHAT DID YOU RECOMMEND REGARDING THE PROPOSED CUSTOMER CHARGES IF THE COMMISSION GRANTS LESS THAN THE INCREASE REQUESTED BY THE COMPANY?

A. I recommended that the proposed customer charges be included in any scale back of rates.[6]

Q. DID THE COMPANY AGREE WITH YOUR RECOMMENDATION?

A. No. Wellsboro witness Gorman disagreed with my recommendation and stated that the proposed customer charges are consistent with the Commission's policy and should be approved as submitted, unless an updated customer cost analysis indicates otherwise.[7]

Q. DO YOU AGREE THAT USING A CUSTOMER COST ANALYSIS TO ASSIST IN DETERMINING PROPOSED CUSTOMER CHARGES IS CONSISTENT WITH COMMISSION POLICY?

A. Yes. The Company is correct that using a customer cost analysis to assist in determining proposed customer charges is consistent with Commission policy. As described above, I did not object to the customer cost analysis submitted by the Company in its filing.

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6 I&E Statement No. 3, pp. 10-11.
7 Wellsboro Statement No. 1R, p. 6.

Q. IS INCLUDING CUSTOMER CHARGES IN A SCALE BACK OF RATES WITHOUT UPDATING THE CUSTOMER COST ANALYSIS CONSISTENT WITH COMMISSION PRECEDENT?

A. Yes. As I stated in my direct testimony, the Commission determined in the 2017 UGI Electric base rate case that, despite the higher customer cost determination in the cost of service study, the customer charges should be reduced for all customers.[8] The Company did not provide any reason or rationale for the Commission to reverse its previous decision.

Q. SHOULD THE COMMISSION REQUIRE THAT AN UPDATED CUSTOMER COST ANALYSIS BE SUBMITTED IN ORDER TO ADJUST THE CUSTOMER CHARGES PROPOSED BY THE COMPANY?

A. No. By the time the Commission provided its final determination regarding the factors that would be needed to adjust the customer cost analysis, the record for this proceeding would be closed. This would deprive the parties of the chance to review the updated customer cost analysis for accuracy and reasonableness. As such, simply including the customer charges in a scale back of rates is a more reasonable method to adjust customer charges. Furthermore, including customer charges in a scale back acknowledges that authorizing a reduced revenue increase corresponds to reductions in the underlying claims, which would include the costs

[8] I&E Statement No. 3, p. 11.

assigned in the customer cost analysis.

Q. DID ANY OTHER PARTY RESPOND TO YOUR PROPOSAL TO INCLUDE THE CUSTOMER CHARGES IN THE SCALE BACK OF RATES?

A. Yes. OCA witness Deupree objected to my recommendation because it is based on the results of the Company's customer cost analysis. Mr. Deupree's position is that the customer cost analysis should not use the Company's requested rate of return (ROR) but instead use either the ROR under present rates or the ROR proposed by the OCA.[9]

Q. DO YOU AGREE WITH THE OCA'S POSITION REGARDING THE ROR USED TO CALCULATE THE CUSTOMER COST ANALAYSIS?

A. No. Using the Company's claimed ROR under proposed rates to determine the customer cost analysis is appropriate because it properly aligns the Company's expenses with its proposed rates whereas using the ROR under present rates to determine proposed customer charges would be a misalignment. Furthermore, while I have no comment on the OCA's proposed ROR itself, the fact that using the OCA's ROR would cause a reduction in the results of the customer cost analysis supports my recommendation to include the customer charges in the scale

[9] OCA Statement No. 3R, pp. 2-5.

back of rates because this change to the ROR directly affects the results of the customer cost analysis. Including the customer charges in the scale back of rates is a simple, reasonable method to account for these changes.

Q. DO YOU WISH TO CHANGE YOUR RECOMMENDATION TO INCLUDE THE CUSTOMER CHARGE IN THE SCALE BACK OF RATES?

A. No. I continue to recommend that the proposed customer charges be included in the scale back of rates if the Commission grants less than the Company's fully requested increase.

SCALE BACK OF RATES

Q. WHAT DID YOU RECOMMEND IF THE COMMISSION GRANTS LESS THAN THE FULL INCREASE?

A. If the Commission grants less than the Company's requested increase, I recommended that the proposed increases be scaled back based on the cost of service study ultimately approved by the Commission. I also recommended that the customer charges that have a proposed increase be included in any scale back of rates.[10]

[10] I&E Statement No. 3, pp. 10-12.

Q. DID ANY PARTY RESPOND TO YOUR SCALE BACK RECOMMENDATIONS?

A. Yes. In response to my scale back recommendation, the Company proposed that if the Commission accepts the Company's allocated cost of service study but reduces its requested revenue requirement, a proportionate scale back to allocate the increase.[11] This proposal is consistent with my recommendation. I discussed the other parties' response to my recommendation to include the customer charges in the scale back above.

Q. DOES THIS CONCLUDE YOUR SURREBUTTAL TESTIMONY?

A. Yes.

[11] Wellsboro Statement No. 1R, p. 6.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No. R-2025-3054392
	:	
Wellsboro Electric Company	:	

VERIFICATION OF
ZACHARI WALKER

I, Zachari Walker, on behalf of the Bureau of Investigation and Enforcement, hereby verify that the documents identified as:

- I&E Statement No. 1
- I&E Exhibit No. 1
- I&E Statement No. 1-SR

were prepared by me or under my direct supervision and control. Furthermore, the facts contained therein are true and correct to the best of my knowledge, information and belief and I expect to be able to prove the same at an evidentiary hearing in this matter. This Verification is made subject to the penalties of 18 Pa.C.S. § 4904 relating to unsworn falsification to authorities.

/s/ Zachari Walker
Zachari Walker
Pennsylvania Public Utility Commission
Bureau of Investigation and Enforcement

Dated: September 2, 2025

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No. R-2025-3054392
	:	
Wellsboro Electric Company	:	

VERIFICATION OF
CHRISTOPHER KELLER

I, Christopher Keller, on behalf of the Bureau of Investigation and Enforcement, hereby verify that the documents identified as:

- I&E Statement No. 2
- I&E Exhibit No. 2
- I&E Statement No. 2-SR

were prepared by me or under my direct supervision and control. Furthermore, the facts contained therein are true and correct to the best of my knowledge, information and belief and I expect to be able to prove the same at an evidentiary hearing in this matter. This Verification is made subject to the penalties of 18 Pa.C.S. § 4904 relating to unsworn falsification to authorities.

/s/ Christopher Keller_____
Christopher Keller
Pennsylvania Public Utility Commission
Bureau of Investigation and Enforcement

Dated: September 3, 2025

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No. R-2025-3054392
	:	
Wellsboro Electric Company	:	

VERIFICATION OF
ETHAN H. CLINE

I, Ethan H. Cline, on behalf of the Bureau of Investigation and Enforcement, hereby verify that the documents identified as:

- I&E Statement No. 3
- I&E Exhibit No. 3
- I&E Statement No. 3-SR

were prepared by me or under my direct supervision and control. Furthermore, the facts contained therein are true and correct to the best of my knowledge, information and belief and I expect to be able to prove the same at an evidentiary hearing in this matter. This Verification is made subject to the penalties of 18 Pa.C.S. § 4904 relating to unsworn falsification to authorities.

*/s/ Ethan H. Cline*_____
Ethan H. Cline
Pennsylvania Public Utility Commission
Bureau of Investigation and Enforcement

Dated: 9/2/25

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
v.	)	**R-2025-3054394**
Citizens' Electric Company of Lewisburg, PA	)	

Direct Testimony and Exhibit of

Greg R. Meyer

OCA Statement 1

On behalf of

Pennsylvania Office of Consumer Advocate

Date Served: July 15, 2025

BRUBAKER & ASSOCIATES, INC.

Project 11858

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
v.	)	**R-2025-3054394**
Citizens' Electric Company of Lewisburg, PA,	)	

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QUALIFICATIONS OF GREG R. MEYER ..... Appendix A

EXHIBIT GRM-1 (CITIZENS)

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
v.	)	**R-2025-3054394**
Citizens' Electric Company of Lewisburg, PA,	)	

Direct Testimony of Greg R. Meyer

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Greg R. Meyer. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q WHAT IS YOUR OCCUPATION?

A I am a consultant in the field of public utility regulation and a Senior Principal with the firm of Brubaker & Associates, Inc. ("BAI"), energy, economic and regulatory consultants.

Q PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A This information is included in Appendix A to my testimony.

Q ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?

A I am appearing on behalf of the Pennsylvania Office of Consumer Advocate ("OCA").

Q HAVE YOU TESTIFIED BEFORE THE PENNSYLVANIA PUBLIC UTILITY COMMISSION ("COMMISSION") IN PRIOR PROCEEDINGS?

A Yes, I have. I provided testimony in Docket R-2024-3046519 (Columbia Gas of Pennsylvania) on behalf of the OCA.

Q PLEASE GIVE A BRIEF OVERVIEW OF YOUR TESTIMONY.

A My testimony will provide a brief overview of the case and discuss various aspects of the revenue requirement of Citizens' Electric Company of Lewisburg, PA ("Citizens" or "Company").

My silence in regard to any issue should not be construed as an endorsement of or acquiescence to the Company's position.

CASE OVERVIEW AND WITNESS INTRODUCTION

Q PLEASE DESCRIBE THE RATE INCREASE THAT CITIZENS FILED.

A On April 30, 2025, Citizens filed a Statement of Reason seeking approval to increase base rates by $1.79 million. Citizens filed the Direct Testimony of five witnesses. Citizens serves approximately 7,176 customers. Citizens uses a Fully Projected Future Test Year ("FPFTY") ending December 31, 2026, a Future Test Year ("FTY") ending December 31, 2025, and a Historical Test Year ("HTY") ending December 31, 2024. Citizens stated in its filing that it must seek a general increase in its rates to recover its costs and to earn a fair return on capital.

Q CAN YOU DESCRIBE THIS RATE FILING IN RELATION TO THE COMPANY'S PRIOR GENERAL RATE INCREASE FILINGS?

A Citizens has filed for general rate increases in 2016, 2019, and 2022, each of which resulted in a grant of a rate increase with an effective date somewhere near nine months of the filing date in each case.

Q PLEASE SUMMARIZE THE TESTIMONY OF OCA'S OTHER EXPERTS IN THIS PROCEEDING.

A The OCA's witnesses touch on most aspects of the Company's rate case.

- My testimony, OCA Statement 1, addresses the Company's proposed claims for its proposed increase in its revenue requirement based on the FPFTY 2026 and makes recommendations for reasonable adjustments to reflect appropriate and normalized revenues and expenses for ratemaking purposes.

- Mr. Christopher Walters, OCA Statement 2, addresses the appropriate capital structure for ratemaking, the Return on Equity ("ROE"), and the impact of the Company's claims for an additional 25 basis points for management performance and size adjustment on the ROE. Mr. Walters recommends a market-based ROE of 9.50%, which is the midpoint of his reasonable range of 9.00% to 10.00% based on the analytical methods he used. The negative adjustment to the Company's revenue requirement based on Mr. Walters' recommended ROE is reflected in the recommended revenue requirement increase presented in my testimony.

- Mr. Michael W. Deupree, OCA Statement 3, is the OCA's expert witness on cost-of-service studies, revenue allocation, and rate design. Mr. Deupree provides adjustments to the Company's allocated class cost of service study, recommendations regarding proposed revenue allocation and rate design for the customer charge.

- Ms. LeeAnn Wise, OCA Statement 4, is the OCA's expert witness on quality of customer service issues, including customer payment fees, security deposits, and payment plans. Ms. Wise recommends that the Company eliminate the $3.95 processing fee charged to customers who pay their utility bills by credit card. Given this recommendation, the resulting increase to the revenue requirement will be reflected in my revenue requirement recommendation.

SUMMARY OF RECOMMENDATIONS

Q PLEASE SUMMARIZE YOUR CONCLUSIONS AND RECOMMENDATIONS.

A My conclusions and recommendations are as follows:

1. I recommend that Citizens' annualized revenues be increased.
2. I recommend that Citizens' uncollectible expense be decreased.
3. I recommend that Citizens' annualized payroll expense be decreased.
4. I recommend that Citizens' non-labor expenses be decreased in Accounts 593 and 920.
5. Finally, I recommend that certain Citizens' Sponsorships and Lobbying costs be disallowed.

Q DO YOU BELIEVE AN INCREASE IN CITIZENS' REVENUES OF APPROXIMATELY $1.79 MILLION WILL RESULT IN JUST AND REASONABLE RATES FOR CITIZENS' CUSTOMERS?

A No. I believe that the base rate increase proposed by Citizens is overstated. I have prepared Table GRM-1 (Citizens) that shows the adjustments I am proposing that reduces the revenue increase sought by Citizens by a total of $686,208. With my recommended adjustments, and the adjustments recommended by OCA Witness Walters (ROE) and OCA Witness Wise (credit card payment fees), Table GRM-1 (Citizens) shows that the Company is only entitled to a $1,108,317 revenue requirement increase.

Table GRM-1 (Citizens)

OCA Revenue Requirement Adjustments

Line	Description	Amount
1	Company Proposed Revenue Requirement Increase[1]	$ 1,794,525
	OCA Adjustments:	
2	Return on Equity	$ (268,215)
3	Rate Revenue	$ (56,136)
4	Uncollectible Expense	$ (5,111)
5	Labor	$ (125,320)
6	Acct 593 and 920	$ (272,331)
7	Sponsorship and Lobbying	$ (2,109)
8	Credit Card Fee	$ 43,014
9	Total OCA Adjustments	$ (686,208)
10	OCA Proposed Revenue Requirement Increase	$ 1,108,317

Source:
[1]OCA-I-1 Attachment A (Schedule A-D) Tab "C1."

REVENUES

Q HAVE YOU REVIEWED THE LEVEL OF ANNUALIZED REVENUES PROPOSED BY CITIZENS FOR INCLUSION IN THIS RATE CASE?

A Yes, I have.

Q DO YOU AGREE WITH THE LEVELS OF ANNUALIZED REVENUES INCLUDED IN CITIZENS' REVENUE REQUIREMENT?

A No. I believe Citizens has understated the Residential, Commercial, and Industrial levels of revenues.

Q PLEASE EXPLAIN WHY YOU BELIEVE CITIZENS HAS UNDERSTATED THE LEVEL OF RESIDENTIAL REVENUES.

A The usage per customer (kilowatt-hour ("kWh") per customer) proposed by Citizens for the Residential class is understated when compared to a 10-year average of usage from 2015-2024 Company annual reports. I have prepared Table GRM-2 (Citizens) below to show the levels of Residential usage from different time periods and the usage level proposed by Citizens.

Table GRM-2 (Citizens)

Residential Usage Analysis

Time Period	Usage (kWh) per Customer
5-Year Average[1]	14,487
10-Year Average[1]	14,617
15-Year Average[1]	14,644
Company Proposed FPFTY[2]	14,488

Sources:

[1]Calculated based on Company Annual reports from 2010 to 2024.

[2]Company Schedule B3.

As can be seen from Table GRM-2 (Citizens), the Residential usage levels proposed by Citizens matches the five-year historical usage level experienced. I recommend using the 10-year usage patterns for the Residential class to annualize revenues. The table also shows that the 10- and 15-year usage patterns are very close to each other and slightly greater than the five-year usage level. Overall, this indicates that the recent years have had milder weather and a longer time period of annualization is warranted.

Q WHAT IS THE RESIDENTIAL REVENUE ADJUSTMENT IMPACT FROM YOUR PROPOSED USAGE PER CUSTOMER?

A Utilizing the 10-year usage per customer results in an increase in annualized Residential revenues of $26,456. I would note that my adjustment to increase Residential revenues also recognizes the effects of uncollectible expense. The adjustment to Residential usage per customer is calculated in Exhibit GRM-1 (Citizens), page 3, and the impact is shown on Exhibit GRM-1 (Citizens), page 2. The energy proposed for Residential customers is shown on Exhibit GRM-1 (Citizens), page 6.

Q DO YOU BELIEVE THE CITIZENS' COMMERCIAL REVENUES ARE ALSO UNDERSTATED?

A Yes, I do. I have prepared Table GRM-3 (Citizens) to show the levels of Commercial usage from different time periods and the usage level proposed by Citizens.

Table GRM-3 (Citizens)

Commercial Usage Analysis

Time Period	Usage (kWh) per Customer
5-Year Average[1]	24,152
10-Year Average[1]	25,907
15-Year Average[1]	26,284
Company Proposed FPFTY[2]	24,027

Sources:

[1]Calculated based on Company Annual reports from 2010 to 2024.

[2]Company Schedule B3.

As can be seen from Table GRM-3 (Citizens) above, the Commercial usage levels proposed by Citizens are lower than the five-, 10-, and 15-year historical usage levels experienced. I recommend using the 10-year usage patterns for the Commercial class to annualize revenues. The table also shows that the 10- and 15-year usage patterns are very close to each other and significantly greater than the five-year usage level. Overall, this indicates that the recent years have had milder weather and a longer time period of annualization is warranted.

Q WHAT IS THE COMMERCIAL REVENUE ADJUSTMENT IMPACT FROM YOUR PROPOSED USAGE PER CUSTOMER?

A Utilizing the 10-year usage per customer results in an increase in annualized Commercial revenues of $21,134. I would note that my adjustment to increase Commercial revenues also recognizes the effects of uncollectible expense. The adjustment to Commercial usage per customer is calculated in Exhibit GRM-1 (Citizens), page 3, and the impact is shown on Exhibit GRM-1 (Citizens), page 2. The energy proposed for Commercial customers is shown on Exhibit GRM-1 (Citizens), page 6.

Q FINALLY, DO YOU BELIEVE CITIZENS' INDUSTRIAL REVENUES ARE ALSO UNDERSTATED?

A Yes, I do. I have prepared Table GRM-4 (Citizens) to show the levels of Industrial usage from different time periods and the usage level proposed by Citizens.

Table GRM-4 (Citizens)

Industrial Usage Analysis

Time Period	Usage (kWh) per Customer
5-Year Average[1]	1,133,866
10-Year Average[1]	1,301,308
15-Year Average[1]	1,290,608
Company Proposed FPFTY[2]	1,109,527

Sources:

[1]Calculated based on Company Annual reports from 2010 to 2024.

[2]Company Schedule B3.

As can be seen from Table GRM-4 (Citizens) above, the Industrial usage levels proposed by Citizens is lower than the five-, 10-, and 15-year historical usage levels experienced. I recommend using the 10-year usage patterns for the Industrial class to annualize revenues. The table also shows that the 10- and 15-year usage patterns are very close to each other and significantly greater than the five-year usage level. Overall, this indicates that the recent years have had milder weather and a longer time period of annualization is warranted.

Q WHAT IS THE INDUSTRIAL REVENUE ADJUSTMENT IMPACT FROM YOUR PROPOSED USAGE PER CUSTOMER?

A Utilizing the 10-year usage per customer results in an increase in annualized Industrial revenues of $8,296. I would note that my adjustment to increase Industrial revenues recognizes the effects of uncollectible expense. The adjustment to Industrial usage per customer is calculated in Exhibit GRM-1 (Citizens), page 4, and the impact is shown on Exhibit GRM-1 (Citizens), page 2. The energy proposed for Industrial customers is shown on Exhibit GRM-1 (Citizens), page 6.

Summing the three rate class revenue adjustments results in a total Citizens' increase to Citizens' revenues of $55,886 and a resulting decrease to Citizens' revenue requirement of $56,136. This is shown on Exhibit GRM-1 (Citizens), page 2.

UNCOLLECTIBLE EXPENSE

Q HAVE YOU REVIEWED THE COMPANY'S PROPOSAL FOR UNCOLLECTIBLE EXPENSE?

A Yes, I have.

Q DO YOU HAVE CONCERNS WITH THE LEVEL OF UNCOLLECTIBLE EXPENSE INCLUDED IN CITIZENS' REVENUE REQUIREMENT?

A Yes. I believe Citizens has overstated the level of uncollectible expenses.

Q PLEASE DISCUSS YOUR RATIONALE ON WHY YOU BELIEVE CITIZENS HAS OVERSTATED THE LEVEL OF UNCOLLECTIBLE EXPENSES.

A Citizens is proposing a level of uncollectible expenses of $30,900. This level of uncollectible expenses reflects a 0.167% bad debt write-off factor. I contend that this bad debt write-off factor is too high, and therefore, the uncollectible expense is too high.

Q WHAT INFORMATION DO YOU HAVE TO SHOW THE BAD DEBT WRITE-OFF FACTOR UTILIZED BY CITIZENS IS TOO HIGH?

A I have prepared Table GRM-5 (Citizens) below that shows the historical levels of bad debt write-offs experienced by Citizens.

Table GRM-5 (Citizens)

Historical Bad Debt Write-off %

Year	Revenues	Net Write-offs	% of Rev
2020	$13,603,836	$ 18,770	0.138%
2021	$13,692,112	$ 18,429	0.135%
2022	$16,929,825	$ 20,270	0.120%
2023	$20,304,827	$ 31,823	0.157%
2024	$16,279,186	$ 24,932	0.153%
5 Year Total	$80,809,786	$ 114,225	0.141%
Company Proposed FPFTY	$18,458,350	$ 30,900	0.167%

Sources:
1. 2020 to 2024 revenues sourced from Company annual reports.
2. 2020 and 2024 Net Write-offs sourced from Company Resposne to OCA Data Request 7-17
3. Company Proposed FPFTY sourced from Company Schedule C1 and C1-1.

As can be seen from the Table GRM-5 (Citizens), the bad debt write-off factor used by Citizens in its FPFTY 2026 of 0.167% is overstated when compared to the five-year historical average of 0.141%. I propose to use the five-year percentage average of bad debt write-offs for annualizing uncollectible expense. Using a five-year average of bad debt write-offs of 0.141% reduces Citizens' uncollectible expenses by $4,809. My adjustment to uncollectible expense results in a decrease to Citizens' revenue requirement of $5,111. My proposed uncollectible expense is calculated on Exhibit GRM-1 (Citizens), page 5, and the revenue requirement impact is shown on Exhibit GRM-1 (Citizens), page 2.

PAYROLL EXPENSE

Q HAVE YOU REVIEWED THE LEVEL OF PAYROLL EXPENSE INCLUDED IN CITIZENS' REVENUE REQUIREMENT?

A Yes, I have.

Q DO YOU BELIEVE THE LEVEL OF PAYROLL EXPENSE INCLUDED IN CITIZENS' REVENUE REQUIREMENT REPRESENTS A REASONABLE LEVEL?

A No. I believe Citizens has overstated the level of payroll expenses for the FPFTY 2026. Citizens is proposing to increase payroll expense by approximately 21%[1] over the payroll level recorded in the HTY 2024.

[1]Percent Change of Schedule C1-1 Total Operating & Maintenance Expense between FPFTY 2026 and HTY 2024.

Q IN YOUR REVIEW OF CITIZENS' PAYROLL EXPENSE, DID YOU DISCOVER THAT CITIZENS IS PROPOSING TO ADD NEW EMPLOYEES TO ITS WORKFORCE?

A Yes. I discovered that Citizens is proposing to add two new employees to its workforce.

Q WHAT IS CITIZENS' CURRENT WORKFORCE NUMBERS?

A I have prepared Table GRM-6 (Citizens) below that shows the historical level of Citizens' employees.

Table GRM-6 (Citizens)

Citizens' Employee Levels

Year	Employee Count (1)
2020	16
2021	18
2022	19
2023	18
2024	18
FTY	19
FPFTY	20

Source:
2020 to 2024 from annual reports;
TYs from OCA 7-12

As can be seen from Table GRM-6 (Citizens), Citizens has included two new employees in its level of payroll expenses for the FPFTY 2026 in this case.

Q DID CITIZENS PROVIDE ANY EXPLANATION IN THEIR DIRECT TESTIMONY FOR THE ADDITION OF TWO NEW EMPLOYEES?

A No. I could not find any reference in the Direct Testimony discussing the need to add two new employees. Therefore, my payroll annualization will not recognize the addition of two new employees.

Q PLEASE DISCUSS THE PROCESS YOU UTILIZED TO ANNUALIZE CITIZENS' PAYROLL EXPENSES.

A I increased the HTY 2024 level of payroll by 4% to reflect a reasonable level of FTY 2025 payroll expenses. I then applied a 4% payroll increase to the FTY 2025 level of payroll expenses to reflect a reasonable FPFTY 2026 annualized level of payroll expenses.

Q WHY DID YOU CHOSE A 4% PAYROLL INCREASE FIGURE?

A It is my experience that a typical range for annual payroll increases are between 3.5% to 4% per year. Therefore, I chose 4% to annualize Citizens' payroll expense.

Q WHAT WAS THE EFFECT OF YOUR PAYROLL ANNUALIZATION?

A My annualized level of payroll expenses resulted in a reduction of payroll expenses of $116,567. This results in a decrease to revenue requirement of $125,320. My proposed payroll expenses are shown on Exhibit GRM-1 (Citizens), pages 14 and 15. The impact of this adjustment is shown on Exhibit GRM-1 (Citizens), page 2.

NON-LABOR OPERATION & MAINTENANCE ("O&M") EXPENSES

Q HAVE YOU PERFORMED A REVIEW OF CITIZENS' NON-LABOR O&M EXPENSE?

A Yes, I have. In reviewing Citizens' expenses, I noticed that the non-labor expenses projected for Accounts 593 (Maintenance of Overhead Lines) and 920 (Administrative and General ("A&G") Salaries) were much greater than recent history would suggest appropriate.

Q WAS THE NON-LABOR EXPENSE GROWTH PROJECTIONS ASSOCIATED WITH THESE TWO ACCOUNTS ADDRESSED IN CITIZENS' TESTIMONY?

A No, not specifically. Citizens' Witness Kathy Stauder notes that "[t]he FPFTY data is based on our projections for the year ending December 31, 2026."[2]

Q WHAT DID YOU FIND WITH RESPECT TO THE NON-LABOR EXPENSES ASSOCIATED WITH ACCOUNT 593 MAINTENANCE OF OVERHEAD LINES?

A In reviewing the non-labor breakout for this account from both the last case and the current case in the workpapers for Exhibit (HSG-1) Schedule C, from the years 2020 to HTY 2024, there was an annual growth of 5.73%.[3] The growth rate projected by Citizens for FTY 2025 non-labor expenses is 20.19%. Then 31.07% growth was added for FPFTY 2026 on top of the FTY 2025 amount. This results in a non-labor expense

[2] *See* Direct Testimony of Kathy Stauder at page 4, lines 5-6.

[3] Compound Annual Growth Rate calculated as (418,821 / 335,141) ^ (1 / (2024-2020)) – 1 = 5.73%.

for this account that is 1.57 times the highest level experienced within the past five years. I have summarized this in Table GRM-7 (Citizens) below.

Table GRM-7 (Citizens)

Account 593 Non-Labor Expense

Year	Expense
2020	$335,141
2021	359,785
2022	N/A*
2023	421,331
2024 HTY	418,821

Forecast	Expense	Growth
2025 FTY	$503,361	20.19%
2026 FPFTY	659,768	31.07%

*Actual non-labor expense for 2022 was not included in the workpapers for either the last case or the current case.

Q HAS THE COMPANY PROVIDED AN EXPLANATION OF HOW EXPENSES WERE PROJECTED?

A Yes. In response to Data Request I&E-RE-14-D, the Company provided the following list of reasons for the increase shown for FTY 2025:

> a. Vegetation Management contract costs came in slightly under budget in 2024 as a result of lower than expected T&E work by the contractor. T&E work is highly influenced by customer requests and, though typically stable, can vary at times. FTY 2025 is budgeted for a higher overall cost based on field assessment of overhead lines and the expectation that T&E work will remain at average levels.
>
> b. Pole Inspection Management contract costs are expected to increase as a result of the geographic area identified for traditional pole inspections, as well as the introduction of an aerial drone inspection

> program that was piloted in 2023 and budgeted for full implementation in 2025.
>
> c. Increase in labor costs driven by additional hires in 2024 and 2025. For budgeting purposes, available field worker labor is forecast to be split across various labor accounts based on historical distributions. In the labor distribution for 2025, a full year's wages for the new lineworker hire from 2024 are reflected, as well as partial year's wages for two expected new hires in 2025.

For FPFTY 2026 increases, the Company provided the following explanation:

> The primary driver for the $159,625 increase from FTY 2025 to FPFTY 2026 is the substantial expected increase in vegetation management contract costs. See Exhibit NJ-6 for copies of the 2025 bids received. The Company was fortunate to secure a bid at near budget for FTY 2025, but the rest of the bid field, as well as verbal communications from contractor representatives indicate that costs are likely to increase substantially in FPFTY 2026.

Q PLEASE RESPOND TO THE EXPLANATION.

A When looking at these explanations, I am struck that there is no discussion of how the Company is exercising cost control. We must keep in mind that the Company is requesting a 57.5% increase over the HTY 2024 non-labor expenses for this account. With growth of that size projected, it is incumbent on the Company to show that it has done all it can to hold the line on expense growth. Absent that showing, it is difficult to say that the requested increase is warranted.

At this point we are to accept merely the bald assertion that costs will increase drastically in the future, well beyond what has been experienced in the recent past. Additionally, one might expect the aerial drone program to provide unaccounted for efficiencies that would serve to offset additional costs.

Q WHAT DID YOU FIND WITH RESPECT TO THE NON-LABOR EXPENSES ASSOCIATED WITH ACCOUNT 920 A&G SALARIES?

A In reviewing the non-labor breakout for this account from both the last case and the current case in the workpapers for Exhibit (HSG-1) Schedule C, from the years 2020 to HTY 2024, there was an annual growth of 3.48%.[4] The growth rate projected by Citizens for FTY 2025 non-labor expenses is 3.59%. Then 19.16% growth was added for FPFTY 2026 on top of the FTY 2025 amount. This results in a non-labor expense for this account that is 1.19 times the highest level experienced within the past five years. I have summarized this in Table GRM-8 (Citizens) below.

Table GRM-8 (Citizens)

Account 920 Non-Labor Expense

Year	Expense
2020	$329,134
2021	328,029
2022	N/A*
2023	391,193
2024 HTY	377,412

Forecast	Expense	Growth
2025 FTY	$390,975	3.59%
2026 FPFTY	465,884	19.16%

*Actual non-labor expense for 2022 was not included in the workpapers for either the last case or the current case.

[4]Compound Annual Growth Rate calculated as (377,412 / 329,134) ^ (1 / (2024-2020)) – 1 = 3.48%.

Q HAS THE COMPANY PROVIDED ANY EXPLANATION OF HOW EXPENSES WERE PROJECTED?

A Yes. In response to Data Request I&E-RE-17-D, the Company provided the following explanation for the growth in the total cost of the account (both the labor and non-labor increases):

> D. The 20.8% increase expected from FTY 2025 to FPFTY 2026 is primarily driven by the planned overlap of positions during 2026. Expected administrative position retirements in 2027 necessitate overlap to allow for knowledge transfer and provide continuity.

Q PLEASE RESPOND TO THE EXPLANATION.

A With my review, I was primarily focused on the non-labor expense recorded to Account 920, and the explanation provided appears to be focused on labor costs. However, even accepting that this explanation addresses the non-labor costs as well, it describes a non-normal operating condition. As such, it is inappropriate to set rates based on non-normal operations. The overlap in positions represents merely a temporary state in operations, and shortly thereafter one can reasonably expect that the cost of the overlapping labor will be discontinued. Normalizing costs improves the utility's incentive to control costs, while awarding one-for-one recovery of expenses in non-normal operating conditions reduces the utility's incentive to control costs.

Q HOW DO YOU PROPOSE TO ADDRESS THE NON-LABOR EXPENSE FOR THESE TWO ACCOUNTS?

A I propose that the historical growth rates between 2020 and HTY 2024 be applied to develop the costs for FTY 2025 and FPFTY 2026. For Account 593, this results in a

non-labor expense level of $468,197, a reduction of $191,571 to the Company's proposed expense. For Account 920, this results in a non-labor expense level of $404,145, a reduction of $61,739 to the Company's proposed expense.

My adjustments to Accounts 593 and 920 result in a decrease to expense of $253,310. This results in a reduction to revenue requirement of $272,331. My adjusted non-labor expense for these two accounts can be seen on Exhibit GRM-1 (Citizens), pages 14 through 17. The impact of my adjustments can be seen on Exhibit GRM-1 (Citizens), page 2.

SPONSORSHIP AND LOBBYING

Q HAVE YOU PERFORMED A REVIEW OF CITIZENS' SPONSORSHIP AND LOBBYING EXPENSE?

A Yes, I have. In response to Data Request I&E-RE-9-D, Citizens provided the Company's Sponsorships and Lobbying expenses that were included in the FPFTY 2026. Citizens is proposing to include $695 and $1,267 in FPFTY 2026 for Sponsorships and Lobbying, respectively.

Q DO YOU BELIEVE THAT THE ABOVE LEVELS OF SPONSORSHIP AND LOBBYING EXPENSES IS APPROPRIATE TO INCLUDE IN THIS CASE?

A No, customers should not have to pay for Sponsorships and Lobbying expenses that are not necessary or beneficial to providing safe and reliable service. These types of activities and expenses are solely for burnishing the reputation of the Company.

Q WHAT IS YOUR RECOMMENDATION REGARDING SPONSORSHIP AND LOBBYING EXPENSES?

A I recommend that these expenses be removed from the revenue requirement. This adjustment would lower the revenue requirement by $2,109. My adjusted expenses are shown on Exhibit GRM-1 (Citizens), page 13. The impact of my adjustment is shown on Exhibit GRM-1 (Citizens), page 2.

OTHER ADJUSTMENTS

Q ARE YOU REFLECTING OTHER ADJUSTMENTS IN YOUR RECOMMENDED REVENUE INCREASE?

A Yes. In Exhibit GRM-1 (Citizens), page 2, and in Table GRM-1 (Citizens), I reflect the adjustment to the Company's revenue requirement increase recommended by OCA Witnesses Walters and Wise, in OCA Statement Nos. 2 and 4, respectively.

Q PLEASE EXPLAIN HOW YOU ADDRESS OCA WITNESS WALTERS' ADJUSTMENT.

A OCA Witness Walters recommends a market-based ROE of 9.50%, which is the midpoint of his reasonable range of 9.00% to 10.00% based on the analytical methods he used. Applying Mr. Walters' recommended ROE results in a negative adjustment to the Company's revenue requirement claim by $268,215.

Q PLEASE EXPLAIN HOW YOU ADDRESS OCA WITNESS WISE'S ADJUSTMENT.

A OCA Witness Wise recommends that the Company eliminate the $3.95 processing fee charged to customers who pay their utility bills by credit card. The total annual revenue that the Company collects in these fees from customers and then forwards to a third-party vendor is $40,010. Applying Ms. Wise's recommendation results in a positive adjustment of $43,014 to the Company's claimed revenue requirement increase.

CONCLUSION

Q DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A Yes, it does.

QUALIFICATIONS OF GREG R. MEYER

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Greg R. Meyer. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q PLEASE STATE YOUR OCCUPATION.

A I am a consultant in the field of public utility regulation and a Senior Principal with the firm of Brubaker & Associates, Inc. ("BAI"), energy, economic and regulatory consultants.

Q PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A I graduated from the University of Missouri in 1979 with a Bachelor of Science Degree in Business Administration, with a major in Accounting. Subsequent to graduation I was employed by the Missouri Public Service Commission. I was employed with the Commission from July 1, 1979 until May 31, 2008.

I began my employment at the Missouri Public Service Commission as a Junior Auditor. During my employment at the Commission, I was promoted to higher auditing classifications. My final position at the Commission was an Auditor V, which I held for approximately ten years.

As an Auditor V, I conducted audits and examinations of the accounts, books, records and reports of jurisdictional utilities. I also aided in the planning of audits and investigations, including staffing decisions, and in the development of staff positions in

which the Auditing Department was assigned. I served as Lead Auditor and/or Case Supervisor as assigned. I assisted in the technical training of other auditors, which included the preparation of auditors' workpapers, oral and written testimony.

During my career at the Missouri Public Service Commission, I presented testimony in numerous electric, gas, telephone and water and sewer rate cases. In addition, I was involved in cases regarding service territory transfers. In the context of those cases listed above, I presented testimony on all conventional ratemaking principles related to a utility's revenue requirement. During the last three years of my employment with the Commission, I was involved in developing transmission policy for the Southwest Power Pool as a member of the Cost Allocation Working Group.

In June of 2008, I joined the firm of Brubaker & Associates, Inc. as a Consultant. Since joining the firm, I have presented testimony and/or testified in the state jurisdictions of Arkansas, Florida, Idaho, Illinois, Indiana, Iowa, Kentucky, Maryland, Missouri, Montana, New Mexico, Ohio, Utah, Washington, Wisconsin and Wyoming. I have also appeared and presented testimony in Alberta and Nova Scotia, Canada. In addition, I have filed testimony at the Federal Energy Regulatory Commission ("FERC"). These cases involved addressing conventional ratemaking principles focusing on the utility's revenue requirement. The firm Brubaker & Associates, Inc. provides consulting services in the field of energy procurement and public utility regulation to many clients including industrial and institutional customers, some utilities and, on occasion, state regulatory agencies.

More specifically, we provide analysis of energy procurement options based on consideration of prices and reliability as related to the needs of the client; prepare rate,

feasibility, economic, and cost of service studies relating to energy and utility services; prepare depreciation and feasibility studies relating to utility service; assist in contract negotiations for utility services, and provide technical support to legislative activities.

In addition to our main office in St. Louis, the firm also has branch offices in Corpus Christi, Texas; Louisville, Kentucky and Phoenix, Arizona.

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Table GRM-1 (Citizens)

OCA Revenue Requirement Adjustments

Line	Description	Amount
1	Company Proposed Revenue Requirement Increase[1]	$ 1,794,525
	OCA Adjustments:	
2	Return on Equity	$ (268,215)
3	Rate Revenue	$ (56,136)
4	Uncollectible Expense	$ (5,111)
5	Labor	$ (125,320)
6	Acct 593 and 920	$ (272,331)
7	Sponsorship and Lobbying	$ (2,109)
8	Credit Card Fee	$ 43,014
9	Total OCA Adjustments	$ (686,208)
10	OCA Proposed Revenue Requirement Increase	$ 1,108,317

Source:
[1]OCA-I-1 Attachment A (Schedule A-D) Tab "C1."

Citizens' Electric Company of Lewisburg

Change Log of OCA Adjustments to Revenue Requirement

Line	Issue	Changed Cells	Starting Revenue Requirement Increase	Ending Revenue Requirement Increase	OCA Adjustment	Notes and Sources
			(1)	(2)	(3)	(4)
1	Return on Equity	Changed Cell E11 on Tab "C1-2" to 9.5%	$ 1,794,525	$ 1,526,309	$ (268,215)	See Mr. Christopher Walters, OCA Statement 2
2	Rate Revenue - Residential	Added 785,507 to Cell D7 on Tab "B3-1"	$ 1,526,309	$ 1,499,735	$ (26,574)	See Mr. Greg Meyer, OCA Statement 1; See Adjustment Schedule 1 for the calculation of additional usage added
3	Rate Revenue - Commercial	Added 2,129,464 to Cell F7 and 14,213 to Cell E7 on Tab "B3-1"	$ 1,499,735	$ 1,478,507	$ (21,228)	See Mr. Greg Meyer, OCA Statement 1; See Adjustment Schedule 1 for the calculation of additional usage added
4	Rate Revenue - Industrial	Added 8,054,804 to Cell G7 on Tab "B3-1"	$ 1,478,507	$ 1,470,174	$ (8,333)	See Mr. Greg Meyer, OCA Statement 1; See Adjustment Schedule 1 for the calculation of additional usage added
5	Uncollectible Expense	Changed Cell I34 on Tab "C1-1" to $26,091	$ 1,470,174	$ 1,465,063	$ (5,111)	See Mr. Greg Meyer, OCA Statement 1; See Adjustment Schedule 1 for the calculation of $26,091
6	Labor	On Tab "WP1_C", changed all Cells with values in Column L from Account 580 to Account 932.4 to reflect a 4% increase in total labor for each year from 2024 in relation to their proportion of expense to the total in Line 53.	$ 1,465,063	$ 1,339,743	$ (125,320)	See Mr. Greg Meyer, OCA Statement 1
7	Account 593	On Tab "WP1_C", changed the non-labor 2026 Accounts 593, 593.5, 593.6 to total $468,197 by using their company proposed proportion multiplied by $468,197.	$ 1,339,743	$ 1,133,787	$ (205,956)	See Mr. Greg Meyer, OCA Statement 1
8	Account 920	Changed Cell Q43 on Tab "WP1_C" to equal $404,145	$ 1,133,787	$ 1,067,412	$ (66,375)	See Mr. Greg Meyer, OCA Statement 1
9	Sponsorship and Lobbying	Subtracted $695 from Cell G55 and $1,267 from Cell G56 on Tab "WP1_C"	$ 1,067,412	$ 1,065,302	$ (2,109)	See Mr. Greg Meyer, OCA Statement 1
10	Credit Card Fee	Added $40,010 to Cell G39 on Tab "WP1_C"	$ 1,065,302	$ 1,108,317	$ 43,014	See Ms. LeeAnn Wise, OCA Statement 4
11				OCA Total Adjustments	$ (686,208)	

Citizens' Electric Company of Lewisburg

Residential Usage per Customer Adjustments

Line	Description	Residential
1	Company Proposed FPFTY Sales (kWh)[1]	87,664,162
2	Company Proposed FPFTY Average Customers[1]	6,051
3	Company Proposed Usage per Customer (Line 1 ÷ Line 2)	14,488
4	OCA Proposed Usage per Customer[2]	14,617
5	OCA Adjustment to Usage per Customer (Line 4 - Line 3)	130
6	OCA Proposed Additional Usage (Line 2 x Line 5)	785,507

Commerical Usage per Customer Adjustments

Line	Description	GLP-1	SH	Total
		(1)	(2)	(3)
7	Company Proposed FPFTY Sales (kWh)[1]	27,208,762	181,607	27,390,368
8	Company Proposed FPFTY Average Customers[1]	1,137	3	1,140
9	Company Proposed Usage per Customer (Line 7 ÷ Line 8)			24,027
10	OCA Proposed Usage per Customer[2]			25,907
11	OCA Adjustment to Usage per Customer (Line 10 - Line 9)			1,880
12	OCA Proposed Additional Usage[3]	2,129,464	14,213	2,143,678

Industrial Usage per Customer Adjustments

Line	Description	GLP-3
13	Company Proposed FPFTY Sales (kWh)[1]	46,600,138
14	Company Proposed FPFTY Average Customers[1]	42
15	Company Proposed Usage per Customer (Line 13 ÷ Line 14)	1,109,527
16	OCA Proposed Usage per Customer[2]	1,301,308
17	OCA Adjustment to Usage per Customer (Line 16 - Line 15)	191,781
18	OCA Proposed Additional Usage (Line 14 x Line 17)	8,054,804

Sources and Notes:

[1]Company Schedule B3-1.

[2]Ten year average of sales divided by average customers from 2020 to 2024 Annual Reports.

[3]Total is Line 8 x Line 11 while the different rate classes are calculated based on a proportion of their usage in Line 7 to the total

Citizens'

Net Write-offs

Year	Revenues	Net Write-offs	% of Rev	
2,020	$ 13,603,836	$ 18,770	0.138%	*Revenues sourced from Annual Reports
2,021	$ 13,692,112	$ 18,429	0.135%	*Net Write Offs from OCA DR 7-17
2,022	$ 16,929,825	$ 20,270	0.120%	
2,023	$ 20,304,827	$ 31,823	0.157%	
2,024	$ 16,279,186	$ 24,932	0.153%	
Total	$ 80,809,786	$ 114,225	0.141%	
HTY	$ 16,378,412	$ 27,330	0.167%	*Uncollectibles Sourced from Company Schedule C1-1
FTY	$ 16,644,983	$ 30,000	0.180%	*Revenues sources from Company Schedule C1
FPFTY Present	$ 16,663,825	$ 30,900	0.185%	
FPFTY Proposed	$ 18,458,350	$ 30,900	0.167%	
	OCA Proposed	$ 26,091	0.141%	

B3-1

Citizens' Electric Company of Lewisburg
Rate Case with Fully Projected Future Test Year 2026
Billing Units, Rates And Revenue At Present Rates
Fully Projected Future Test Year 2026

		Residential	Space Heating	GLP-1	GLP-3	Municipal Boulevard	Outdoor Lighting	Total
1					**BILLING UNITS**			
2	kWh Sales	88,449,669	195,820	29,338,226	54,654,942	75,543	213,869	172,928,069
3								
4	Number of Bills	72,612	36	13,644	504	156	312	87,264
5	Average Monthly Bills	6,051	3	1,137	42	13	26	7,272
6								
7					**Annual Billing Units- Public Lighting and Street Lighting HY 2024**			
8	Rate 1				MBL- Meter	13		
9	Rate 2				MBL- Post	535		
10	Rate 3				Monthly revenue	2,179	9,602	
11	Rate 4							
12					**RATES AND CHARGES**			
13					**Tariff Rates**			
14	Customer Charge	$13.10	$20.19	$16.00	$55.00	$3.84		
15						$3.98	Average	
16	Energy Block 1	$0.03368	$0.04413	$0.00963	$0.009490		$14.66	
17	Energy Block 2				$0.001030		Count	
18	Reservation Chge				$2.51		655	
19	Voltage Discount				($0.234420)			
20	Block 1 kWh = Demand X				30			
21	Demand Block 1			$3.74	$5.37			
22								
23					**COMPUTATION OF REVENUE**			
24	Customer Charge Revenue	951,217	727	218,304	27,720	26,151	115,224	1,339,343
25								
26	Distribution kWh Revenue	2,978,985	8,642	282,527	88,085			3,358,239
27	Distribution Demand Revenue	0	0	611,814	801,634			1,413,448
28	*Total Distribution Revenue*	2,978,985	8,642	894,341	889,720	0	0	4,771,687
29	**Total Distribution Revenue**	$3,930,202	$9,368	$1,112,645	$917,440	$26,151	$115,224	$6,111,030
30	*FTY 2025*	*3,887,618*	*8,741*	*1,092,138*	*908,267*	*26,151*	*115,224*	*6,038,139*
31								

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Citizens' Electric Company of Lewisburg
Rate Case with Fully Projected Future Test Year 2026
Billing Units, Rates And Revenue At Present Rates
Fully Projected Future Test Year 2026

		Residential	Space Heating	GLP-1	GLP-3	Municipal Boulevard	Outdoor Lighting	Total
32	Block 1 kWh 2024				3,757,740			
33	Block 2 kWh 2024				50,897,202			
34								
35	Demand kW 2024			163,587	131,225			
36	New Customers, Load Factor	29.4%			318			
37	Demand kW			163,587	131,543			295,130
38								
39	Reservation kW- annaul				150,600			150,600
40	Reservation (CR-kW)- annual				(41,529)			
41	Voltage Discount- kW				58,964			58,964
42	Block 1 kWh				3,500			3,500
43								
44	Customers December 2024	6,001	3	1,137	40	13	26	7,220
45	Customers added (lost) 2025	25	0	0	2	0	0	27
46	Customers added (lost) 2026	25						25
47	Forecast Customers 2026	6,051	3	1,137	42	13	26	7,247
48	Average Annual UPC, 2020-202	14,488	60,536	23,930	1,144,553			
49	Existing Customers	6,001	3	1,137	40	13	26	7,220
50	Forecast kWh 2026, Existing	86,939,784	181,607	27,208,762	45,782,138	75,543	213,869	160,401,703
51	Projected New Customers 2025	362,189			537,000			899,189
52	Projected New Customers 2026	362,189			281,000			643,189
53	Forecast kWh 2026	87,664,162	181,607	27,208,762	46,600,138	75,543	213,869	161,944,081
54								

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Citizens' Electric Company of Lewisburg
Rate Case with Fully Projected Future Test Year 2026

Net Operating Income And Rates of Return
HY 2024, FTY 2025 and FPFTY 2026
Answer to 52 Pa. Code 53.52 c[1]

Line	Description	Present Rates HY 12/31/2024		Present Rates FTY 12/31/2025	Present Rates FPFTY 12/31/2026	Full Revenue Requirement FPFTY 12/31/2026	Proposed Rates FPFTY 12/31/2026
		Per Books	Distribution Only	Distribution Only	Distribution Only	Distribution Only	Distribution Only
1	**REVENUE**						
2	Residential	$3,689,870	$3,689,870	$3,887,618	$3,930,202		$5,148,260
3	Comm and indus	1,981,976	1,981,976	2,009,146	2,039,453		2,507,965
4	Lighting	141,375	141,375	141,375	141,375		194,201
5	Rounding	0					
6	Electric operating revenue	5,813,222	5,813,222	6,038,139	6,111,030	7,219,346	7,850,427
7	Other revenue, net	99,224	99,224	102,026	104,137	104,137	104,137
8	GSSR	10,504,818					
9	Other, net	(38,851)	(38,851)				
10	Total Revenue	16,378,412	5,873,594	6,140,165	6,215,167	7,323,484	7,954,564
11	*Annual kWH*	*150,899,872*	*150,899,872*	*161,300,892*	*172,928,069*	*172,928,069*	*172,928,069*
12	**EXPENSES**				Increase	1,108,317	
13	Purchased electricity	10,504,818					
14	Distribution	1,556,654	1,556,654	1,743,703	1,684,968	1,684,968	1,684,968
15	Customer acct & coll	536,669	536,669	542,259	567,426	567,426	567,426
16	Admin & general	1,268,350	1,268,350	1,429,095	1,513,029	1,513,029	1,513,029
17	Total Operating expense	13,866,491	3,361,673	3,715,057	3,765,423	3,765,423	3,765,423
18							
19	Depreciation expense	1,126,159	1,126,159	1,323,181	1,409,998	1,409,998	1,409,998
20							
21	Taxes other than income	978,426	427,276	441,195	446,255	511,645	548,834
22							
23	Total Expenses	15,971,075	4,915,108	5,479,433	5,621,675	5,687,066	5,724,255
24							
25	Net operating income before income taxes	407,337	958,487	660,732	593,491	1,636,417	2,230,309
26							
27	Income tax expense	124,998	162,212	95,752	66,479	367,802	539,390
28	NET UTILITY OPERATING INCOME (LOSS) (A)	$282,338	$796,274	$564,980	$527,012	$1,268,615	$1,690,919
29							0.099167
30	RATE BASE (B)		$15,121,720	$16,244,077	$17,051,278	$17,051,278	$17,051,278
31	RATE OF RETURN ON RATE BASE (A / B)		5.27%	3.48%	3.09%	7.44%	9.92%

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Citizens' Electric Company of Lewisburg
Rate Case with Fully Projected Future Test Year 2026

Net Operating Income And Rates of Return
HY 2024, FTY 2025 and FPFTY 2026
Answer to 52 Pa. Code 53.52 c[1] - Support Sheet No. 1
Support Sheet No. 1- Operating Expense and Going-Level Adjustments

Line	Acct.	Account Description	Year 2023	Year 2024	Year 2024 to Year 2025	Year 2025	Year 2025 to Year 2026	Year 2026	Labor			
									Year 2023	HY 2024	FTY 2025	FPFTY 2026
			Actual	Actual	Changes	Forecast	Changes	Forecast	Actual	Actual	Forecast	Forecast
1	Distribution Expenses											
2	580	Operations Supv & Eng	139,449	147,492	3,650	151,142	(3,197)	147,944	65,639	69,376	70,506	66,366
3	582	Station Expense	20,968	5,258	8,721	13,979	(500)	13,478	8,446	1,974	5,821	5,373
4	583	Overhead Line	242,610	226,033	8,894	234,927	(2,517)	232,410	106,207	80,793	99,056	91,436
5	585	Street Lighting	8,095	12,169	(7,144)	5,025	(102)	4,922	2,438	4,820	2,195	2,026
6	586	Meter Expense	25,262	24,042	24,916	48,958	(441)	48,517	18,234	(7,401)	22,504	20,773
7	587	Customer Installation	39,845	41,115	12,650	53,765	511	54,276	16,746	19,074	21,945	20,257
8	588	Miscellaneous Distribution	395,055	455,104	31,311	486,415	(3,565)	482,850	116,645	121,176	127,162	117,380
9	589	Rents	520	530	(5)	525	0	525	0	0	0	0
10		*Total Operating & Maintenanc*	871,804	911,743	82,992	994,735	(9,813)	984,922	334,356	289,812	349,187	323,611
11												
12	592	Maintenance of Station Equipmen	2,202	25,133	(8,301)	16,832	(350)	16,482	1,134	11,213	7,461	6,887
13	593	Maintenance of Overhead Lines	563,525	558,565	108,646	667,211	(47,914)	619,297	142,193	139,744	163,850	151,100
14	594	Maintenance of Underground Line	16,532	13,331	1,030	14,361	(135)	14,226	6,923	5,237	6,159	5,686
15	595	Maintain Line Transformers	85,912	31,968	(5,001)	26,967	(219)	26,748	9,440	7,462	7,377	6,809
16	596	Maint. Street Light & Signal	22,847	15,914	7,682	23,596	(304)	23,292	10,192	6,283	9,176	8,470
17	597	Maintenance of Misc. Distrib Plan	0	0	0	0	0	0	0	0	0	0
18		*Total Maintenance*	691,018	644,911	104,057	748,968	(48,922)	700,046	169,882	169,939	194,023	178,952
19		*Total Operating & Maintenanc*	1,562,822	1,556,654	187,049	1,743,703	(58,735)	1,684,968	504,238	459,751	543,210	502,563
20												

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Citizens' Electric Company of Lewisburg
Rate Case with Fully Projected Future Test Year 2026

Net Operating Income And Rates of Return
HY 2024, FTY 2025 and FPFTY 2026
Answer to 52 Pa. Code 53.52 c[1] - Support Sheet No. 1
Support Sheet No. 1- Operating Expense and Going-Level Adjustments

Line	Acct.	Account Description	Year 2023	Year 2024	Year 2024 to Year 2025	Year 2025	Year 2025 to Year 2026	Year 2026	Labor Year 2023	Labor HY 2024	Labor FTY 2025	Labor FPFTY 2026
21	Customer Accounting & Collection Expenses:											
22	902	Meter Reading Expense	25,085	26,338	(338)	26,000	0	26,000	0	0	0	0
23	903	Customer Records & Collection	474,976	483,001	3,258	486,259	29,076	515,335	176,064	174,418	174,043	162,322
24	904	Uncollectible Accounts	31,906	27,330	2,670	30,000	(3,909)	26,091	0	0	0	0
25		*Total Customer Accting & Coll*	531,968	536,669	5,590	542,259	25,167	567,426	176,064	174,418	174,043	162,322
26												
27	Administrative & General Expenses:											
28	920	Administrative & General Salaries	742,994	700,832	31,998	732,830	50,327	783,157	351,801	323,420	341,855	379,012
29	921	Office Supplies & Expenses	243,492	145,653	101,335	246,988	7,410	254,397	0	0	0	0
30	923	Outside Services Employed	47,103	40,008	(3,008)	37,000	1,110	38,110	0	0	0	0
31	924	Property Insurance	11,431	11,190	(131)	11,059	0	11,059	0	0	0	0
32	925	Injuires & Damages	27,561	27,341	1,566	28,907	0	28,907	0	0	0	0
33	926	Employee Pensions & Benefits	6,204	7,497	1,003	8,500	255	8,755	0	0	0	0
34	928	Regulatory Commission	105,515	70,128	18,080	88,208	28,979	117,187	0	0	0	0
35	930	Miscellaneous General	105,300	110,600	291	110,891	1,365	112,256	0	0	0	0
36	932	Maintenance of General Property	121,914	155,101	9,612	164,713	(5,511)	159,201	47,569	62,272	64,116	59,184
37		*Total Administrative & General*	1,411,514	1,268,350	160,745	1,429,095	83,934	1,513,029	399,370	385,692	405,971	438,197
38												
39		**Total O&M Expense**	**$3,506,304**	**$3,361,673**	**$353,384**	**$3,715,057**	**$50,366**	**$3,765,423**	**$1,079,671**	**$1,019,861**	**$1,123,224**	**$1,103,082**
40												

41			Year 2023	Year 2024	Year 2024 to Year 2025	Year 2025	Year 2025 to Year 2026	Year 2026
42		Labor	1,079,671	1,019,861	103,363	1,123,224	(20,142)	1,103,082
43		Overhead	1,197,394	1,239,081	45,537	1,284,618	(44,373)	1,240,245
44		Transportation	101,038	87,328	1,310	88,638	13,682	102,320
45		Materials	1,128,201	1,015,403	203,174	1,218,577	67,961	1,286,537
46			3,506,304	3,361,673	353,384	3,715,057	17,127	3,732,184

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Citizens' Electric Company of Lewisburg
Rate Case with Fully Projected Future Test Year 2026
Net Operating Income And Rates of Return
Support Sheet No. 2- Cost of Capital and Fair Rate of Return Based upon Hypothetical Ratemaking Capital Structure
12/31/2025 and 12/31/2026

Line	Type of Capital		Ratios (1)	12/31/26 Cost Rate	12/31/26 Weighted Cost
1	Long-Term Debt	(B)	51.06%	5.470%	2.79%
2	Preferred Stock				
3	Common Equity	(A)	48.94%	9.50%	4.65%
4	Total		100.00%		7.44%
5				Using	7.44000%
6					
7	(A) Recommended hypothetical capital structure ratios as discussed in direct testimony.				

WP1_C **Citizens' Electric Company of Lewisburg**
Rate Case with Fully Projected Future Test Year 2026
Workpaper 1 to Schedule C
Historic and Forecast O&M
Years 2013-2026

Line	Account	Acct No	2023 Total	2024 Total	2025 Total	2026 Total
1	Ops Exp Eng	580	139,449	147,492	151,142	147,944
1	Station Exp	582	20,968	5,258	13,979	13,478
2	OH. Line Exp	583	190,281	191,665	181,002	180,609
3	OH. Line Contra (to Plant)	583.97	(25,570)	(17,480)	(18,034)	(19,270)
4	URD Line Exp	584	77,898	51,848	71,959	71,071
5	Dusk to Dawn Lgts Exp	585DD	3,103	5,271	937	925
6	St Lgt & Signal Exp	585SLS	4,992	6,898	4,088	3,997
7	Meter Exp	586	43,734	53,805	56,277	56,306
8	Meter Contra (to Plant)	586.98	(18,472)	(29,763)	(7,319)	(7,789)
9	Customer Inst Exp	587	39,845	41,115	53,765	54,276
10	Misc. Distribution Exp	588	164,611	211,070	207,816	201,538
11	Tools	588.5	5,685	13,479	8,000	8,500
12	Travel	588.6	74,111	25,691	81,116	80,665
13	Safety & Training	588.7	38,404	76,891	42,600	45,000
14	Mapping	588.8	43,586	23,327	36,446	36,709
15	Retiree Non Alloc BC+SERP	588.1	68,659	104,646	110,437	110,437
16	Rents	589	520	530	525	525
17	Total Ops		871,804	911,743	994,735	984,922
18					*994,735*	
19	Maint. Sub-Station Exp	592	2,202	25,133	16,832	16,482
20	Maint. OH. Line Exp	593	322,454	303,733	379,720	313,080
21	Veg Mgmt	593.5	193,991	214,296	209,204	261,671
22	Pole Insp Mgmt	593.6	47,080	40,536	78,287	44,546
23	Maint. URD Line Exp	594	16,532	13,331	14,361	14,226
24	Maint. Line Xfmr	595	85,912	31,968	26,967	26,748
25	Maint. Dusk to Dawn Lgts	596DD	6,450	1,307	6,605	6,499
26	Maint. St Lgt & Signal Exp	596SLS	16,397	14,607	16,992	16,793
27	Maint. of Meter Exp	597	0	0	0	0
28	Total Maintenance		691,018	644,911	748,968	700,046
29					*748,968*	
30	Meter Reading Exp	902	25,085	26,338	26,000	26,000
31	Customer Records Exp	903	474,976	483,001	486,259	515,335
32	Uncollectibles	904	31,906	27,330	30,000	30,900
33	Total Customer Accounts		531,968	536,669	542,259	572,235

WP1_C **Citizens' Electric Company of Lewisburg**
Rate Case with Fully Projected Future Test Year 2026
Workpaper 1 to Schedule C
Historic and Forecast O&M
Years 2013-2026

Line	Account	Acct No	2023 Total	2024 Total	2025 Total	2026 Total
34					542,259	
35	Administrative	920	742,994	700,832	732,830	783,157
36	Misc Admin	921	103,236	15,126	106,327	109,517
37	Misc Admin- Travel	921.1	20,548	7,817	10,000	10,300
38	Misc Admin- Comm	921.2	32,667	40,255	34,014	35,035
39	Misc Admin- Call Center	921.3	77,386	82,455	85,379	87,940
40	Misc Admin- Transp	921.4	9,655	0	11,267	11,605
41	Outside Services	923	47,103	40,008	37,000	38,110
42	Property Insurance	924	11,431	11,190	11,059	11,059
43	Injury & Damage Exp	925	27,561	27,341	28,907	28,907
44	CEO Insurance	926.01	(8,321)	(5,885)	0	0
45	Benefits	926.00	14,525	13,382	8,500	8,755
46	Reg Commission Exp	928	105,515	70,128	88,208	117,187
47	General Advertising	930.1	1,061	655	1,000	335
48	Misc. General Exp	930.2	89,888	93,095	94,112	95,668
49	Director's Committee	930.3	14,352	16,850	15,779	16,252
50	Misc. General Plant	932.4	121,914	155,101	164,713	159,201
51	Total General Labor		1,411,514	1,268,350	1,429,095	1,513,029
52						
53	**Subtotal**		**3,506,304**	**3,361,673**	**3,715,057**	**3,770,232**
54			0	0	0	0
55	Capital		537,607	0	556,938	724,306
56	Misc. A/R		0	0	0	0
57	Truck		5,609	0	0	0
58	OH. Labor(Vac,Hol,Sick,Funeral,Sup		323,568	0	298,015	370,762
59						
60	**Total**		**4,373,088**	**3,361,673**	**4,570,010**	**4,865,300**

WP1_C **Citizens' Electric Company of Lewisburg**
Rate Case with Fully Projected Future Test Y
Workpaper 1 to Schedule C
Historic and Forecast O&M
Years 2013-2026

Line	Account	Acct No	2023 Labor	2024 Labor	2025 Labor	2026 Labor	2023 OH	2024 OH	2025 OH	2026 OH
1	Ops Exp Eng	580	65,639	69,376	70,506	66,366	73,810	78,116	80,636	81,578
1	Station Exp	582	8,446	1,974	5,821	5,373	9,871	2,264	6,657	6,605
2	OH. Line Exp	583	76,244	81,245	76,212	70,350	90,703	86,954	87,163	86,474
3	OH. Line Contra (to Plant)	583.97		(12,893)						
4	URD Line Exp	584	29,963	12,441	22,843	21,086	33,959	15,023	26,126	25,919
5	Dusk to Dawn Lgts Exp	585DD	345	3,214	407	376	2,728	1,569	465	462
6	St Lgt & Signal Exp	585SLS	2,093	1,606	1,788	1,650	2,363	3,632	2,044	2,028
7	Meter Exp	586	18,234	22,362	22,504	20,773	17,980	25,203	25,737	25,534
8	Meter Contra (to Plant)	586.98		(29,763)						
9	Customer Inst Exp	587	16,746	19,074	21,945	20,257	17,868	21,926	25,098	24,900
10	Misc. Distribution Exp	588	78,384	100,860	93,125	85,961	79,239	103,026	106,506	105,664
11	Tools	588.5								
12	Travel	588.6	28,955		28,510	26,317	32,533	25,691	32,606	32,349
13	Safety & Training	588.7		19,559				22,411		
14	Mapping	588.8	9,306	757	5,527	5,102	10,515	816	6,321	6,271
15	Retiree Non Alloc BC+SERP	588.1								
16	Rents	589						530		
17	Total Ops		334,356	289,812	349,187	323,611	371,570	387,161	399,361	397,784
18										
19	Maint. Sub-Station Exp	592	1,134	11,213	7,461	6,887	843	13,236	8,533	8,466
20	Maint. OH. Line Exp	593	133,851	117,957	156,035	144,032	152,261	155,041	178,455	125,638
21	Veg Mgmt	593.5	7,497	21,787	5,815	5,259	7,527	24,661	6,651	4,588
22	Pole Insp Mgmt	593.6	846	0	2,000	1,809	907	0	2,287	1,578
23	Maint. URD Line Exp	594	6,923	5,237	6,159	5,686	8,026	6,471	7,044	6,989
24	Maint. Line Xfmr	595	9,440	7,462	7,377	6,809	11,103	9,494	8,437	8,370
25	Maint. Dusk to Dawn Lgts	596DD	2,888	550	1,813	1,674	2,822	617	2,074	2,058
26	Maint. St Lgt & Signal Exp	596SLS	7,303	5,733	7,362	6,796	7,491	7,586	8,420	8,354
27	Maint. of Meter Exp	597	0	0	0	0	0	0	0	0
28	Total Maintenance		169,882	169,939	194,023	178,952	190,979	217,106	221,902	166,039
29										
30	Meter Reading Exp	902	0	0	0	0	0	0	0	0
31	Customer Records Exp	903	176,064	174,418	174,043	162,322	192,911	197,831	199,051	199,527
32	Uncollectibles	904								
33	Total Customer Accounts		176,064	174,418	174,043	162,322	192,911	197,831	199,051	199,527

WP1_C **Citizens' Electric Company of Lewisburg**
Rate Case with Fully Projected Future Test Y
Workpaper 1 to Schedule C
Historic and Forecast O&M
Years 2013-2026

Line	Account	Acct No	2023 Labor	2024 Labor	2025 Labor	2026 Labor	2023 OH	2024 OH	2025 OH	2026 OH
34										
35	Administrative	920	351,801	323,420	341,855	379,012	391,193	368,269	390,975	404,145
36	Misc Admin	921								
37	Misc Admin- Travel	921.1								
38	Misc Admin- Comm	921.2								
39	Misc Admin- Call Center	921.3								
40	Misc Admin- Transp	921.4								
41	Outside Services	923								
42	Property Insurance	924								
43	Injury & Damage Exp	925	0	0	0	0				
44	CEO Insurance	926.01								
45	Benefits	926.00								
46	Reg Commission Exp	928								
47	General Advertising	930.1								
48	Misc. General Exp	930.2								
49	Director's Committee	930.3								
50	Misc. General Plant	932.4	47,569	62,272	64,116	59,184	50,741	68,714	73,329	72,750
51	Total General Labor		399,370	385,692	405,971	438,197	441,934	436,983	464,304	476,895
52										
53	**Subtotal**		**1,079,671**	**1,019,861**	**1,123,224**	**1,103,082**	**1,197,394**	**1,239,081**	**1,284,618**	**1,240,245**
54										
55	Capital		537,607		556,938	570,902	0	0	0	0
56	Misc. A/R		0		0	0	0	0	0	0
57	Truck		5,609		0	0	0	0	0	0
58	OH. Labor(Vac,Hol,Sick,Funeral,Sup		323,568		298,015	370,762				
59										
60	**Total**		**1,946,455**	**1,019,861**	**1,978,177**	**2,044,746**	**1,197,394**	**1,239,081**	**1,284,618**	**1,240,245**

WP1_C **Citizens' Electric Company of Lewisburg**
Rate Case with Fully Projected Future Test Y
Workpaper 1 to Schedule C
Historic and Forecast O&M
Years 2013-2026

Line	Account	Acct No	2023 Transp	2024 Transp	2025 Transp	2026 Transp	2023 Material	2024 Material	2025 Material	2026 Material
1	Ops Exp Eng	580								
1	Station Exp	582		0			2,651	1,020	1,500	1,500
2	OH. Line Exp	583	23,463	23,466	17,127	23,285	(128)		500	500
3	OH. Line Contra (to Plant)	583.97		2,251			(25,570)	(6,838)	(18,034)	(19,270)
4	URD Line Exp	584	12,286		2,990	4,065	1,690	24,384	20,000	20,000
5	Dusk to Dawn Lgts Exp	585DD	30	488	65	88	0	0	0	0
6	St Lgt & Signal Exp	585SLS	474	1,660	176	239	62	0	80	80
7	Meter Exp	586	5,075	4,512	5,460	7,423	2,445	1,728	2,576	2,576
8	Meter Contra (to Plant)	586.98					(18,472)		(7,319)	(7,789)
9	Customer Inst Exp	587	5,231		6,668	9,065	0	115	54	54
10	Misc. Distribution Exp	588	4,026	4,678	4,804	6,532	2,961	2,506	3,381	3,381
11	Tools	588.5		3,237			5,685	10,242	8,000	8,500
12	Travel	588.6					12,622		20,000	22,000
13	Safety & Training	588.7		233			38,404	34,688	42,600	45,000
14	Mapping	588.8		0			23,765	21,754	24,598	25,336
15	Retiree Non Alloc BC+SERP	588.1					68,659	104,646	110,437	110,437
16	Rents	589					520		525	525
17	Total Ops		50,585	40,525	37,289	50,696	115,294	194,245	208,898	212,831
18										
19	Maint. Sub-Station Exp	592	225	623	809	1,100	0	61	29	29
20	Maint. OH. Line Exp	593	36,306	30,857	44,338	42,777	37	(122)	892	633
21	Veg Mgmt	593.5	2,467	1,087	1,738	1,677	176,500	166,761	195,000	250,148
22	Pole Insp Mgmt	593.6	378	0	0	0	44,949	40,536	74,000	41,159
23	Maint. URD Line Exp	594	1,515	1,546	1,097	1,491	67	77	60	60
24	Maint. Line Xfmr	595	3,605	1,094	1,154	1,569	61,764	13,918	10,000	10,000
25	Maint. Dusk to Dawn Lgts	596DD	740	140	139	188	0	0	2,579	2,579
26	Maint. St Lgt & Signal Exp	596SLS	1,603	1,288	1,209	1,644	0	0	0	0
27	Maint. of Meter Exp	597	0	0	0	0	0	0	0	0
28	Total Maintenance		46,839	36,635	50,483	50,446	283,318	221,231	282,560	304,608
29										
30	Meter Reading Exp	902	0	0	0	0	25,085	26,338	26,000	26,000
31	Customer Records Exp	903	3,558	949	866	1,178	102,444	109,803	112,299	112,299
32	Uncollectibles	904					31,906	27,330	30,000	30,900
33	Total Customer Accounts		3,558	949	866	1,178	159,435	163,471	168,299	169,199

WP1_C **Citizens' Electric Company of Lewisburg**
Rate Case with Fully Projected Future Test Y
Workpaper 1 to Schedule C
Historic and Forecast O&M
Years 2013-2026

Line	Account	Acct No	2023 Transp	2024 Transp	2025 Transp	2026 Transp	2023 Material	2024 Material	2025 Material	2026 Material
34										
35	Administrative	920		9,143						
36	Misc Admin	921					103,236	15,126	106,327	109,517
37	Misc Admin- Travel	921.1					20,548	7,817	10,000	10,300
38	Misc Admin- Comm	921.2					32,667	40,255	34,014	35,035
39	Misc Admin- Call Center	921.3					77,386	82,455	85,379	87,940
40	Misc Admin- Transp	921.4					9,655		11,267	11,605
41	Outside Services	923					47,103	40,008	37,000	38,110
42	Property Insurance	924					11,431	11,190	11,059	11,059
43	Injury & Damage Exp	925	0	0	0	0	27,561	27,341	28,907	28,907
44	CEO Insurance	926.01					(8,321)	(5,885)	0	0
45	Benefits	926.00					14,525	13,382	8,500	8,755
46	Reg Commission Exp	928					105,515	70,128	88,208	117,187
47	General Advertising	930.1					1,061	655	1,000	1,030
48	Misc. General Exp	930.2					89,888	93,095	94,112	96,935
49	Director's Committee	930.3					14,352	16,850	15,779	16,252
50	Misc. General Plant	932.4	56	76	0	0	23,548	24,039	27,267	27,267
51	Total General Labor		56	9,219	0	0	570,154	436,456	558,820	599,900
52										
53	**Subtotal**		**101,038**	**87,328**	**88,638**	**102,320**	**1,128,201**	**1,015,403**	**1,218,577**	**1,286,537**
54										
55	Capital		0		0	153,404				
56	Misc. A/R		0		0	0				
57	Truck									
58	OH. Labor(Vac,Hol,Sick,Funeral,Sup									
59										
60	**Total**		**101,038**	**87,328**	**88,638**	**255,724**	**1,128,201**	**1,015,403**	**1,218,577**	**1,286,537**

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No. R-2025-3054394
	:	
Citizens' Electric Co. of Lewisburg, PA	:	

VERIFICATION

I, Greg R. Meyer, hereby state that the facts above set forth in my Direct Testimony, OCA Statement No. 1, are true and correct to the best of my knowledge, information, and belief and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa.C.S. § 4904 (relating to unsworn falsification to authorities).

DATED: July 15, 2025

Signature: /s/ Greg R. Meyer
Greg R. Meyer

Address: Brubaker & Associates Inc.
16690 Swingley Ridge Road, Suite 140
Chesterfield, MO 63017

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
v.	)	**R-2025-3054393**
Valley Energy, Inc.	)	

Direct Testimony and Exhibit of

Greg R. Meyer

OCA Statement 1

On behalf of

Pennsylvania Office of Consumer Advocate

Date Served: July 15, 2025

BRUBAKER & ASSOCIATES, INC.

Project 11858

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
v.	)	**R-2025-3054393**
Valley Energy, Inc.	)	

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Direct Testimony of Greg R. Meyer

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EXHIBIT GRM-1 (VALLEY)

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
v.	)	**R-2025-3054393**
Valley Energy, Inc.	)	

Direct Testimony of Greg R. Meyer

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Greg R. Meyer. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q WHAT IS YOUR OCCUPATION?

A I am a consultant in the field of public utility regulation and a Senior Principal with the firm of Brubaker & Associates, Inc. ("BAI"), energy, economic and regulatory consultants.

Q PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A This information is included in Appendix A to my testimony.

Q ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?

A I am appearing on behalf of the Pennsylvania Office of Consumer Advocate ("OCA").

Q HAVE YOU TESTIFIED BEFORE THE PENNSYLVANIA PUBLIC UTILITY COMMISSION ("COMMISSION") IN PRIOR PROCEEDINGS?

A Yes, I have. I provided testimony in Docket R-2024-3046519 (Columbia Gas of Pennsylvania) on behalf of the OCA.

Q PLEASE GIVE A BRIEF OVERVIEW OF YOUR TESTIMONY.

A My testimony will provide a brief overview of the case and discuss various aspects of the revenue requirement of Valley Energy, Inc. ("Valley" or "Company").

My silence in regard to any issue should not be construed as an endorsement of or acquiescence to the Company's position.

CASE OVERVIEW AND WITNESS INTRODUCTION

Q PLEASE DESCRIBE THE RATE INCREASE THAT VALLEY FILED.

A On April 30, 2025, Valley filed a Statement of Reason seeking approval to increase base rates by $1.6 million. Valley filed the Direct Testimony of six witnesses. Valley serves more than 7,420 customers. Valley uses a Fully Projected Future Test Year ("FPFTY") ending December 31, 2026, a Future Test Year ("FTY") ending December 31, 2025, and a Historical Test Year ("HTY") ending December 31, 2024. Valley stated in its filing that it must seek a general increase in its rates to recover its costs and to earn a fair return on capital.

Q CAN YOU DESCRIBE THIS RATE FILING IN RELATION TO THE COMPANY'S PRIOR GENERAL RATE INCREASE FILINGS?

A Valley has filed for general rate increases in 2019 and 2022, each of which resulted in a grant of a rate increase with an effective date somewhere near nine months of the filing date in each case.

Q PLEASE SUMMARIZE THE TESTIMONY OF OCA'S OTHER EXPERTS IN THIS PROCEEDING.

A The OCA's witnesses touch on most aspects of the Company's rate case.

- My testimony, OCA Statement 1, addresses the Company's proposed claims for its proposed increase in its revenue requirement based on the FPFTY 2026 and makes recommendations for reasonable adjustments to reflect appropriate and normalized revenues and expenses for ratemaking purposes.

- Mr. Christopher Walters, OCA Statement 2, addresses the appropriate capital structure for ratemaking, the Return on Equity ("ROE"), and the impact of the Company's claims for an additional 25 basis points for management performance and size adjustment on the ROE. Mr. Walters recommends a market-based ROE of 9.50%, which is the midpoint of his reasonable range of 9.00% to 10.00% based on the analytical methods he used. The negative adjustment to the Company's revenue requirement based on Mr. Walters' recommended ROE is reflected in the recommended revenue requirement increase presented in my testimony.

- Mr. Michael W. Deupree, OCA Statement 3, is the OCA's expert witness on cost-of-service studies, revenue allocation, and rate design. Mr. Deupree provides recommendations solely regarding proposed revenue allocation and rate design for the customer charge.

- Ms. LeeAnn Wise, OCA Statement 4, is the OCA's expert witness on quality of customer service issues, including customer payment fees, security deposits, and payment plans. Ms. Wise recommends that the Company eliminate the $3.95 processing fee charged to customers who pay their utility bills by credit card. Given this recommendation, the resulting increase to the revenue requirement will be reflected in my revenue requirement recommendation.

SUMMARY OF RECOMMENDATIONS

Q PLEASE SUMMARIZE YOUR CONCLUSIONS AND RECOMMENDATIONS.

A My conclusions and recommendations are as follows:

1. I recommend that Valley's annualized payroll expense be decreased.
2. I recommend a reduction to Valley's non-labor expenses in Accounts 880 and 925.
3. I recommend that Valley's proposed depreciation expense be decreased.
4. I raise a concern about the apparent mismatch between the revenues and expenses related to the purchased gas adjustment clause.

Q DO YOU BELIEVE AN INCREASE IN VALLEY'S REVENUES OF APPROXIMATELY $1.6 MILLION WILL RESULT IN JUST AND REASONABLE RATES FOR VALLEY'S CUSTOMERS?

A No. I believe that the base rate increase proposed by Valley is overstated. I have prepared Table GRM-1 (Valley) that shows the adjustments I am proposing that reduces the revenue increase sought by Valley by a total of $662,469. With my adjustments, and the adjustments of OCA Witness Walters (ROE) and OCA Witness Wise (credit card payment fees), Table GRM-1(Valley) shows that the Company is only entitled to a $963,630 revenue increase.

Table GRM-1 (Valley)

OCA Revenue Requirment Adjustments

Line	Description	Amount
1	Company Proposed Revenue Requirement Increase[1]	$ 1,626,099
	OCA Adjustments:	
2	Return on Equity	$ (375,363)
3	Labor	$ (19,892)
4	Acct 880 and 925	$ (67,810)
5	Depreciation	$ (267,031)
6	Credit Card Fee	$ 67,627
7	Total OCA Adjustments	$ (662,469)
8	OCA Proposed Revenue Requirement Increase	$ 963,630

Source:
[1]OCA-I-1 Attachment A (Schedule A-D) Tab "C1."

PAYROLL EXPENSE

Q HAVE YOU REVIEWED THE LEVEL OF PAYROLL EXPENSE INCLUDED IN VALLEY'S REVENUE REQUIREMENT?

A Yes, I have.

Q DO YOU BELIEVE THE LEVEL OF PAYROLL EXPENSE INCLUDED IN VALLEY'S REVENUE REQUIREMENT REPRESENTS A REASONABLE LEVEL?

A No. I believe Valley has overstated the level of payroll expenses for the FPFTY 2026. Valley is proposing to increase payroll expense by approximately 10%[1] over the payroll level recorded in the HTY 2024.

Q PLEASE DISCUSS THE PROCESS YOU UTILIZED TO ANNUALIZE VALLEY'S PAYROLL EXPENSES.

A I increased the HTY 2024 level of payroll by 4% to reflect the level of FTY 2025 payroll expenses. I then applied a 4% payroll increase to the FTY 2025 level of payroll expenses to reflect the FPFTY 2026 annualized level of payroll expenses.

Q WHY DID YOU CHOSE A 4% PAYROLL INCREASE FIGURE?

A It is my experience that a typical range for annual payroll increases is between 3.5% to 4% per year. Therefore, I chose 4% to annualize Valley's payroll expense.

Q WHAT WAS THE EFFECT OF YOUR PAYROLL ANNUALIZATION?

A My annualized level of payroll expenses resulted in a reduction of payroll expenses of $19,488. This results in a reduction to revenue requirement of $19,892. My proposed

[1]Percent Change of Schedule C1-1 Total Operating & Maintenance Expense between FPFTY 2026 and HTY 2024.

payroll expenses are shown on Exhibit GRM-1 (Valley), page 7. The impact of this adjustment is shown on Exhibit GRM-1 (Valley), page 2.

NON-LABOR OPERATIONS AND MAINTENANCE ("O&M") EXPENSES

Q HAVE YOU REVIEWED VALLEY'S O&M EXPENSES?

A Yes, and I noticed that the projections for Accounts 880 (Other Distribution Expenses) and 925 (Injuries and Damages Expense) were much greater than recent history would suggest appropriate.

Q WERE EITHER OF THESE ACCOUNTS SPECIFICALLY ADDRESSED IN TESTIMONY?

A Yes. Account 880 was specifically addressed. Valley Witness Jamie Beale states that "[f]or 2025, we made an adjustment to the HTY expenses to include expenses that were previously allocated to Account 880.45 and for a new recuring expense for Environmental System Research Institute (ESRI) cloud services that will work with the Company's Geographic Information System (GIS)."[2] Reviewing the projections for this account included in Exhibit JB-4, we can see that the account drops from $114,706 in HTY 2024 to $54,435 in FTY 2025 and then grows to $70,684 in FPFTY 2026.

And while Account 925 (where liability insurance premiums and injury claim costs are typically booked) is not specifically mentioned in testimony, Valley Witness Melissa Sullivan notes that "C&T has obtained reasonable premiums for Directors &

[2] *See* Direct Testimony of Jamie Beale at page 5, lines 5-9.

Officers ("D&O"), liability, and property insurance for its electric affiliates through Federated Rural Electric Cooperative Insurance Company."[3]

Beyond these two statements, I found no other specific mentions of these accounts and saw no support for their projected balances in the testimony provided by Valley.

Q PLEASE EXPLAIN YOUR CONCERNS REGARDING ACCOUNT 880.

A My concern is that even with the balances forecasted to be less than the HTY 2024 expense level, the account appears to be extremely overstated when compared with historical levels. From at least 2010 to 2023, the expense level ranged from around $1,900 to $7,250 and did not exceed that amount. And without explanation, in HTY 2024 the expense then grows by 1,482% to $114,706. I have summarized this history, along with the Company's forecast in Table GRM-2 (Valley).

[3] *See* Direct Testimony of Melissa Sullivan at page 11, lines 13-15.

Table GRM-2 (Valley)

Review of Account 880

Year	Expense
Historical	
2010	$1,921
2011	2,020
2012	1,931
2013	1,855
2014	2,073
2015	2,687
2016	2,555
2017	3,642
2018	3,893
2019	3,958
2020	4,416
2021	4,393
2022	4,903
2023	7,250
2024	**114,706**
Forecast	
2025	$54,435
2026	70,684

Sources:

2010-2024: Valley Energy, Inc. Annual Reports to the Pennsylvania Public Utility Commission

2025-2026: Exhibit__(HSG-1), Schedule C1-1

Even if the expense is then dropped to the proposed FPFTY 2026 level of $70,684, it represents an 875% growth over the 2023 level. These projections represent a massive growth in this account over the historical levels and have not been adequately supported by specific evidence by the Company.

Q WHAT IS YOUR PROPOSAL FOR THE ACCOUNT 880 EXPENSE LEVEL?

A Looking at the Company's response to Data Request I&E-RS-1-D, Attachment A,[4] it appears that there was no labor expense charged to this account prior to the projections for FTY 2025 and FPFTY 2026. Since I address labor in another part of this testimony, I propose to reduce the non-labor portion of this account down to the 2023 level. According to Exhibit__(HSG-1), Schedule C1-1, the non-labor portion of the account projected for FPFTY 2026 is $42,702. Reducing this amount to $7,250 would reduce the Company's Account 880 expense by $35,452.

Q PLEASE EXPLAIN YOUR CONCERNS REGARDING ACCOUNT 925.

A Similar to my concern with the projections for Account 880, the Account 925 forecast is also significantly higher than recent history would suggest appropriate. Given that this account includes the costs associated with injury claims, one would expect it to bounce around a bit and a review of the history confirms that expectation. From the period 2010 through HTY 2024, we see the account oscillate up and down between a low of $49,652 (2013) and the high of $93,900 (2024). I have summarized this history, along with the Company's forecast in Table GRM-3 (Valley).

[4]In this attachment, *See* Tab C1-1.

Table GRM-3 (Valley)

Review of Account 925

Year	Expense
Historical	
2010	$69,015
2011	72,650
2012	52,213
2013	49,652
2014	56,396
2015	55,419
2016	60,294
2017	56,695
2018	55,616
2019	79,058
2020	89,148
2021	87,139
2022	70,051
2023	83,066
2024	**93,900**
Forecast	
2025	$108,657
2026	124,881

Sources:

2010-2024: Valley Energy, Inc. Annual Reports to the Pennsylvania Public Utility Commission

2025-2026: Exhibit__(HSG-1), Schedule C1-1

As can be seen from this review, the projections increase the HTY 2024 expense by 16% for FTY 2025 and another 15% in FPFTY 2026. This growth in expense has not been adequately supported by specific evidence by the Company.

Q WHAT IS YOUR PROPOSAL FOR THE ACCOUNT 925 EXPENSE LEVEL?

A Absent specific evidence for increasing this expense 33% over 2024 levels,[5] I propose an adjustment to hold Account 925 to the HTY 2024 level of expense. This results in a decrease of $30,981 to the Company's proposed expense in FPFTY 2026.

My adjustments to Accounts 880 and 925 result in a decrease to expense of $66,433 and reduces revenue requirement by $67,810. My adjusted expense levels are shown on Exhibit GRM-1 (Valley), pages 7 through 9, and the impacts of these adjustments are shown on Exhibit GRM-1 (Valley), page 2.

DEPRECIATION

Q HAVE YOU REVIEWED THE LEVEL OF DEPRECIATION EXPENSE INCLUDED IN VALLEY'S REVENUE REQUIREMENT?

A Yes. I have reviewed Valley's depreciation calculation.

Q DID YOU DISCOVER ANY ISSUES WITH THE LEVEL OF DEPRECIATION EXPENSE PROPOSED BY VALLEY?

A Yes. I found two accounts where I contend the depreciation expense included in Valley's revenue requirement is incorrect.

[5] (124,881 / 93,900) – 1 = 33%.

Q WHAT TWO PLANT ACCOUNTS DO YOU BELIEVE DO NOT REFLECT THE CORRECT LEVEL OF DEPRECIATION EXPENSE?

A I contend that Plant Accounts 391 and 396 do not reflect the proper level of depreciation expense.

Q PLEASE DESCRIBE THE PLANT INVESTMENT IN ACCOUNTS 391 AND 396.

A The investment in each account is listed below:

- Plant Account 391 – Office Furniture & Equipment
- Plant Account 396 – Power Operated

Q PLEASE DISCUSS YOUR CONCERNS WITH THE ANNUALIZED DEPRECIATION EXPENSE INCLUDED IN PLANT ACCOUNT 391.

A Valley proposes to include $161,942 of depreciation expense in its FPFTY 2026 revenue requirement.[6] However, Plant Account 391 will be fully depreciated in FTY 2025. Therefore, there is no need to depreciate those assets for purposes of the FPFTY 2026. I, therefore, propose that the $161,942 be removed from Valley's expense.

[6]Schedule C3 at page 2, line 24.

Q PLEASE DISCUSS YOUR CONCERNS WITH PLANT ACCOUNT 396.

A Annualized depreciation expense for Plant Account 396, as proposed by Valley in the FPFTY 2026, is $58,744.[7] Applying that total to the plant investment results in an accumulated depreciation reserve balance overcollection of $199 at the end of the FPFTY 2026. I, therefore, propose to reduce the annual level of depreciation expense for Plant Account 396 to reflect three-year recovery of the annual expense ($58,545). In this way, Plant Account 396 will be fully recovered during the period new rates are in effect in this rate case and will not create an overcollection of depreciation expense for Plant Account 396.

Q WHAT ADJUSTMENT ARE YOU PROPOSING FOR PLANT ACCOUNT 396?

A I am proposing to reduce the annual level of depreciation expense to reflect a three-year recovery of $58,545 or an adjustment of $39,229 to Valley's proposed annualized level of depreciation expense.

Q WHAT IS THE TOTAL DEPRECIATION EXPENSE ADJUSTMENT YOU ARE PROPOSING FOR PLANT ACCOUNTS 391 AND 396?

A I propose to reduce Valley's annualized depreciation expense by $201,171. This adjustment would also lower Valley's proposed revenue requirement by $267,031. My adjusted depreciation expense is shown on Exhibit GRM-1 (Valley), pages 5 and 6. The impact of my adjustments can be seen on Exhibit GRM-1 (Valley), page 2.

[7]Schedule C3 at page 2, line 29.

REVENUE/EXPENSE PURCHASED GAS ADJUSTMENT ("PGA")

Q HAVE YOU REVIEWED THE REVENUE REQUIREMENT ADJUSTMENT PROPOSED BY VALLEY TO REMOVE PURCHASED GAS EXPENSE FROM THE REVENUES AND EXPENSES OF VALLEY?

A Yes, I have.

Q DO YOU HAVE ANY CONCERNS WITH THE ADJUSTMENTS PROPOSED BY VALLEY?

A Yes. The PGAs proposed by Valley create a significant revenue requirement impact for the distribution rate case. Specifically, Valley proposes to reduce revenues associated with purchase gas by approximately $2.6 million.[8] In addition, Valley proposes a purchase gas expense adjustment of approximately $3.7 million.[9] These PGAs create a negative revenue requirement impact of approximately $1.1 million due to the difference in the revenue and expense PGAs.

Q MUST THESE TOTALS EQUAL?

A Not necessarily. However, there is an approximate 18% difference between the revenue adjustment and the expense adjustment proposed by Valley. This is a significant difference between expense and revenue recognition.

[8]As shown on Company Schedule C1, Per Books Total Revenue $8,529,574 minus Distribution Only Revenues of $5,955,553 equals $2,574,021.

[9]Company Schedule C1 at line 10.

Q HOW WOULD YOU LIKE TO PROCEED IN THIS RATE CASE?

A I would propose that Valley be given the opportunity to explain the difference between the revenue and expense adjustments. Parties can then review these explanations and determine if they are reasonable. At this point in time, I am not proposing an adjustment to set the revenue and expense adjustments equal to each other. I reserve the right to propose an adjustment in later testimonies.

Q ARE YOU AWARE OF THE OTHER UTILITIES (CITIZENS' ELECTRIC COMPANY OF LEWISBURG ("CITIZENS") AND WELLSBORO ELECTRIC COMPANY ("WELLSBORO") HAVING SIMILAR ADJUSTMENTS?

A Citizens does not have this concern as Citizens adjusted its revenues and expenses by the same totals. Wellsboro has a similar problem as Valley, but the revenue requirement effect is opposite of that effect for Valley.

Q DO YOU HAVE ANY OTHER CONCERNS REGARDING VALLEY'S PROPOSED REVENUE REQUIREMENT?

A Yes. I have some concerns regarding Industrial revenues. OCA has issued discovery on this issue but the response is still outstanding. I reserve the right to file Supplemental Testimony once that response has been provided.

OTHER ADJUSTMENTS

Q ARE YOU REFLECTING OTHER ADJUSTMENTS IN YOUR RECOMMENDED REVENUE INCREASE?

A Yes. In Exhibit GRM-1 (Valley), page 2, and in Table GRM-1 (Valley), I reflect the adjustments to the Company's revenue requirement increase recommended by OCA Witnesses Walters and Wise, in OCA Statements 2 and 4, respectively.

Q PLEASE EXPLAIN HOW YOU ADDRESS OCA WITNESS WALTERS' ADJUSTMENT.

A OCA Witness Walters recommends a market-based ROE of 9.50%, which is the midpoint of his reasonable range of 9.00% to 10.00% based on the analytical methods he used. Applying Mr. Walters' recommended ROE results in a negative adjustment to the Company's revenue requirement claim by $375,363.

Q PLEASE EXPLAIN HOW YOU ADDRESS OCA WITNESS WISE'S ADJUSTMENT.

A OCA Witness Wise recommends that the Company eliminate the $3.95 processing fee charged to customers who pay their utility bills by credit card. The total annual revenue that the Company collects in these fees from customers and then forwards to a third-party vendor is $66,253. Applying Ms. Wise's recommendation results in a positive adjustment of $67,627 to the Company's claimed revenue requirement increased.

CONCLUSION

Q DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A Yes, it does.

QUALIFICATIONS OF GREG R. MEYER

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Greg R. Meyer. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q PLEASE STATE YOUR OCCUPATION.

A I am a consultant in the field of public utility regulation and a Senior Principal with the firm of Brubaker & Associates, Inc. ("BAI"), energy, economic and regulatory consultants.

Q PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A I graduated from the University of Missouri in 1979 with a Bachelor of Science Degree in Business Administration, with a major in Accounting. Subsequent to graduation I was employed by the Missouri Public Service Commission. I was employed with the Commission from July 1, 1979 until May 31, 2008.

I began my employment at the Missouri Public Service Commission as a Junior Auditor. During my employment at the Commission, I was promoted to higher auditing classifications. My final position at the Commission was an Auditor V, which I held for approximately ten years.

As an Auditor V, I conducted audits and examinations of the accounts, books, records and reports of jurisdictional utilities. I also aided in the planning of audits and investigations, including staffing decisions, and in the development of staff positions in

which the Auditing Department was assigned. I served as Lead Auditor and/or Case Supervisor as assigned. I assisted in the technical training of other auditors, which included the preparation of auditors' workpapers, oral and written testimony.

During my career at the Missouri Public Service Commission, I presented testimony in numerous electric, gas, telephone and water and sewer rate cases. In addition, I was involved in cases regarding service territory transfers. In the context of those cases listed above, I presented testimony on all conventional ratemaking principles related to a utility's revenue requirement. During the last three years of my employment with the Commission, I was involved in developing transmission policy for the Southwest Power Pool as a member of the Cost Allocation Working Group.

In June of 2008, I joined the firm of Brubaker & Associates, Inc. as a Consultant. Since joining the firm, I have presented testimony and/or testified in the state jurisdictions of Arkansas, Florida, Idaho, Illinois, Indiana, Iowa, Kentucky, Maryland, Missouri, Montana, New Mexico, Ohio, Utah, Washington, Wisconsin and Wyoming. I have also appeared and presented testimony in Alberta and Nova Scotia, Canada. In addition, I have filed testimony at the Federal Energy Regulatory Commission ("FERC"). These cases involved addressing conventional ratemaking principles focusing on the utility's revenue requirement. The firm Brubaker & Associates, Inc. provides consulting services in the field of energy procurement and public utility regulation to many clients including industrial and institutional customers, some utilities and, on occasion, state regulatory agencies.

More specifically, we provide analysis of energy procurement options based on consideration of prices and reliability as related to the needs of the client; prepare rate,

feasibility, economic, and cost of service studies relating to energy and utility services; prepare depreciation and feasibility studies relating to utility service; assist in contract negotiations for utility services, and provide technical support to legislative activities.

In addition to our main office in St. Louis, the firm also has branch offices in Corpus Christi, Texas; Louisville, Kentucky and Phoenix, Arizona.

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Table GRM-1 (Valley)

OCA Revenue Requirment Adjustments

Line	Description	Amount
1	Company Proposed Revenue Requirement Increase[1]	$ 1,626,099
	OCA Adjustments:	
2	Return on Equity	$ (375,363)
3	Labor	$ (19,892)
4	Acct 880 and 925	$ (67,810)
5	Depreciation	$ (267,031)
6	Credit Card Fee	$ 67,627
7	Total OCA Adjustments	$ (662,469)
8	OCA Proposed Revenue Requirement Increase	$ 963,630

Source:
[1]OCA-I-1 Attachment A (Schedule A-D) Tab "C1."

Valley Energy

Change Log of OCA Adjustments to Revenue Requirement

Line	Issue	Changed Cells	Starting Revenue Requirement Increase (1)	Ending Revenue Requirement Increase (2)	OCA Adjustment (3)	Notes and Sources (4)
1	Return on Equity	Changed Cell E9 to 9.5% on Tab "C1-2"	$ 1,626,099	$ 1,250,736	$ (375,363)	See Mr. Christopher Walters, OCA Statement 2
2	Labor	On Tab "WP1_C", changed Cells H8 to H27 to reflect a 4% increase in total labor for each year from 2024 in relation to their proportion of expense to the total in Row 28.	$ 1,250,736	$ 1,230,844	$ (19,892)	See Mr. Greg Meyer, OCA Statement 1
3	Account 880	Subtracted $35,452 from non-labor Account 880 Cells on Tab "WP1_C" in proportion to their company proposed non-labor 2026 level over their total non-labor 2026 level.	$ 1,230,844	$ 1,194,658	$ (36,187)	See Mr. Greg Meyer, OCA Statement 1
4	Account 925	Subtracted $30,981 from non-labor Account 925 Cells on Tab "WP1_C" in proportion to their company proposed non-labor 2026 level over their total non-labor 2026 level.	$ 1,194,658	$ 1,163,035	$ (31,623)	See Mr. Greg Meyer, OCA Statement 1
5	Depreciation	On Tab "C3", removed the value from Cell AC32 and reduced Cell AC37 to $19,515.	$ 1,163,035	$ 896,004	$ (267,031)	See Mr. Greg Meyer, OCA Statement 1; $19,515 reflects a 3 year amortization of the remaining expense.
6	Credit Card Fee	Added 66,253 to Cell H91 on Tab "WP1_C"	$ 896,004	$ 963,630	$ 67,627	See Ms. LeeAnn Wise, OCA Statement 4
7				OCA Total Adjustments	$ (662,469)	

C1

Valley Energy, Inc. (PA)
Rate Case with Fully Projected Future Test Year 2026
Net Operating Income And Rates of Return
Years Ended 12/31/2024, 12/31/2025 and 12/31/2026
Answer to 52 Pa. Code 53.52 c[1]

Line	Description	Historic Year December 31, 2024		Future Test Year December 31, 2025	Present Rates Fully Projected Future Test Year December 31, 2026	Revenue Requirement Fully Projected Future Test Year December 31, 2026	Proposed Rates Fully Projected Future Test Year December 31, 2026
		Per Books	Distribution Only	Distribution Only	Distribution Only	Distribution Only	Distribution Only
1	REVENUE						
2	Residential	$4,526,671	$2,823,518	$3,135,633	$3,159,547		3,713,054
3	Commercial and industrial	1,764,263	893,396	976,270	976,270		1,145,683
4	Transportation	2,217,436	2,217,436	2,321,925	2,347,099		2,587,838
5	Operating revenue	8,508,370	5,934,349	6,433,828	6,482,916	7,446,547	7,446,576
6	Other revenue, net	21,204	21,204	23,575	23,575	23,575	23,575
7	Total Revenue	8,529,574	5,955,553	6,457,402	6,506,491	7,470,121	7,470,150
8	*ccf*	*32,948,558*		*34,886,478*	*34,930,969*	*34,930,969*	*34,930,969*
9	EXPENSES				Increase	963,630	
10	Purchased gas (in revenue)	3,650,808					
11	Distribution	1,885,489	1,885,489	1,725,247	1,892,877	1,892,877	1,892,877
12	Customer accounting & collection	649,422	649,422	742,899	832,271	841,096	841,096
13	Rate case expense normalization				92,222	92,222	92,222
14	Administrative & general expenses	1,119,082	1,119,082	1,194,040	1,242,963	1,242,963	1,242,963
15	Total Operating expenses	7,304,802	3,653,994	3,662,186	4,060,333	4,069,158	4,069,158
16							
17	Depreciation expense	1,307,234	1,307,234	1,425,492	1,341,376	1,341,376	1,341,376
18	Taxes other than income	29,354	29,354	31,385	33,587	33,587	33,587
19							
20	Total Expenses	8,641,390	4,990,582	5,119,063	5,435,297	5,444,122	5,444,122
21							
22	Oper Inc (Loss) before Income Tax	(111,816)	964,972	1,338,339	1,071,194	2,025,999	2,026,029
23							
24	Income tax expense	(353,801)	28,530	91,834	(82,746)	193,117	193,126
25	NET UTILITY OPERATING INCOME (LOSS) (A)	$241,986	$936,442	$1,246,505	$1,153,940	$1,832,882	$1,832,903
26							
27	RATE BASE (B)	$21,798,301	$21,798,301	$23,553,480	$25,386,179	$25,386,179	$25,386,179
28	RATE OF RETURN ON RATE BASE (	1.11%	4.30%	5.29%	4.55%	7.22%	7.22%
29							

C1-2

Valley Energy, Inc. (PA)
Rate Case with Fully Projected Future Test Year 2026

Support Sheet No. 2- Summary of Cost of Capital and Fair Rate of Return Based upon a Hypothetical Ratemaking Capital Structure
12/31/2026

Line	Type of Capital	Ratios (1)	Cost Rate	Weighted Cost Ra
1	Long-Term Debt	51.06%	5.03%	2.57%
2	Common Equity	48.94%	9.50%	4.65%
3	Total	100.00%		7.22%
4	TargetROR			7.22%
5				
6	[1] Recommended hypothetical capital structure ratios as discussed in direct testimony.			

C3

Valley Energy, Inc. (PA)
Rate Case with Fully Projected Future Test Year 2026
Original Cost of Utility Plant in Service
Years Ended 12/31/2024, 12/31/2025 and 12/31/2026
Answer to 52 Pa. Code 53.52 c[3]

					Original Cost				Original Cost					Accumulated Depreciation
				12/31/2024	Year 2025	Year 2025	12/31/2025	Year 2026	Year 2026	12/31/2026		Year 2024	12/31/2024
Line	Acct No.	Account Title		Balance	Additions	Removals	Balance	Additions	Removals	Balance	Depr. Rate	Depr Exp	Balance
1	*Distribution Plant.*												
2	114	Gas Plant Acquisition Adjustment		3,361,289			3,361,289			3,361,289	3.47%	88,183	2,847,221
3	366	Trans. Structures and improvements	(A)	117,592	0		117,592	0		117,592	0.62%	730	7,146
4	367	Trans. Mains	(A)	1,917,201	0		1,917,201	0		1,917,201	1.79%	34,311	1,225,993
5	369	Trans. Meas / Reg Sta Equp	(A)	402,427	0		402,427	0		402,427	4.40%	17,723	296,228
6	374	Land & Land Rights		15,652	0		15,652	0		15,652	4.40%		0
7	375	Structures and improvements		204,060	1,218,878		1,422,938	457,937		1,880,875	2.63%	5,363	105,540
8	376S	Mains- Steel		3,820,156	43,909		3,864,065	44,080		3,908,144	3.15%	120,867	2,769,349
9	376P	Mains- Plastic		11,410,116	223,134	(434)	11,632,816	1,188,320	(404)	12,820,732	2.02%	226,954	3,788,947
10	378	Meas / Reg Sta Equp		1,590,567	406,925		1,997,492	244,879		2,242,371	6.72%	100,343	1,221,758
11	380S	Services- Steel		581,198	0	(9,027)	572,171	0	(10,385)	561,786	3.04%	18,399	218,783
12	380P	Services- Plastic		9,843,941	767,950	(1,364)	10,610,526	1,055,387	(14,366)	11,651,547	3.41%	318,053	4,396,438
13	381	Meters		1,945,136	47,842		1,992,978	61,305		2,054,284	2.74%	62,737	1,135,963
14	381RC	Transponders- Res/Comm		1,010,228			1,010,228			1,010,228	2.74%	22,968	312,762
15	381AMR	Meters-AMR		282,510	2,009		284,519	9,121		293,640	2.74%	3,870	8,670
16	381Prot	Meters-Protection		61,435	10,611		72,046	0		72,046	2.74%	842	1,356
17	383	House regulators		335,586	4,500		340,086	4,500		344,586	3.22%	10,792	260,864
18	385	Indu Meas / Reg Sta Equp		1,260,536	26,400		1,286,936	13,200		1,300,136	4.11%	40,510	856,743
19	387	Other equipment		9,978	0		9,978	0		9,978	3.66%	364	7,651
20	Total Distribution Plant			38,169,608	2,752,157	(10,826)	40,910,940	3,078,729	(25,156)	43,964,513		1,073,009	19,461,412
22	*General Plant*												
23	390	Structures & Improvements		4,055,042	0		4,055,042	0		4,055,042	2.43%	74,191	870,711
24	391	Office Furniture & Equipment		1,230,002	6,200		1,236,202	0		1,236,202	13.10%	267,559	1,115,240
25	391C	Computer equipment		147,442	147,442		294,884	125,750		420,634	6.75%	9,552	9,952
26	392	Transportation Equipment		1,214,676	80,000		1,294,676	100,000		1,394,676	12.00%	68,719	1,030,813
27	393	Stores Equipment		48,547	20,000		68,547	0		68,547	6.67%	2,804	25,535
28	394	Tools, Shop & Garage Equipment		717,363	68,750		786,113	45,000		831,113	5.00%	27,591	523,999
29	396	Power Operated		499,528	0		499,528	0		499,528	11.76%	48,647	382,238
30	397	Communication Equipment		245,077	500		245,577	0		245,577	6.67%	10,527	179,026
31	398	Miscellaneous Equipment		14,718			14,718			14,718	6.67%	895	1,790
32	301	Intangible plant, organization		22,107			22,107			22,107	0.00%		
33	389	Land & Land Rights		572,424			572,424			572,424	0.00%		
34		Total General Plant		8,766,926	322,892	0	9,089,818	270,750	0	9,360,568		510,485	4,139,304
36		Less: Acquisition		(3,361,289)	0	0	(3,361,289)	0	0	(3,361,289)		(88,183)	(2,847,221)
37		Total Plant in Service		$43,575,245	$3,075,049	($10,826)	$46,639,469	$3,349,479	($25,156)	$49,963,792		$1,495,311	$20,753,495
38		Less: Clearing, Charged to NY		$46,936,534			$50,000,758			$53,325,081		(188,077)	$23,600,716
39				$46,936,534			$50,000,758			$53,325,081		$1,307,234	$23,600,716

C3

Valley Energy, Inc. (PA)
Rate Case with Fully Projected Future Test Year 20
Original Cost of Utility Plant in Service
Years Ended 12/31/2024, 12/31/2025 and 12/31/202
Answer to 52 Pa. Code 53.52 c[3]

Line	Acct No.	Account Title	Accumulated Depreciation Year 2025 Depr Exp	Accumulated Depreciation Year 2025 Removals	Accumulated Depreciation 12/31/2025 Balance	Accumulated Depreciation Year 2026 Depr Exp	Accumulated Depreciation Year 2026 Removals	Accumulated Depreciation 12/31/2026 Balance	Net Book Value 12/31/2026 Balance
1	*Distribution Plant.*								
2	114	Gas Plant Acquisition Adjustment	116,637		2,963,858	116,637		3,080,494	280,795
3	366	Trans. Structures and improvements	729		7,875	729		8,604	108,988
4	367	Trans. Mains	34,318		1,260,311	34,318		1,294,629	622,572
5	369	Trans. Meas / Reg Sta Equp	17,707		313,935	17,707		331,642	70,785
6	374	Land & Land Rights	689		689	689		1,377	14,275
7	375	Structures and improvements	21,395		126,935	43,445		170,380	1,710,495
8	376S	Mains- Steel	121,026		2,890,375	122,412		3,012,788	895,357
9	376P	Mains- Plastic	232,738	(434)	4,021,251	246,985	(404)	4,267,832	8,552,900
10	378	Meas / Reg Sta Equp	120,559		1,342,317	142,459		1,484,776	757,594
11	380S	Services- Steel	17,668	(9,027)	227,424	17,394	(10,385)	234,433	327,353
12	380P	Services- Plastic	348,772	(1,364)	4,743,846	379,813	(14,366)	5,109,292	6,542,255
13	381	Meters	53,952		1,189,915	55,447		1,245,363	808,921
14	381RC	Transponders- Res/Comm	27,680		340,442	27,680		368,122	642,106
15	381AMR	Meters-AMR	7,768		16,438	7,921		24,359	269,281
16	381Prot	Meters-Protection	1,829		3,185	1,974		5,159	66,887
17	383	House regulators	10,878		271,742	11,023		282,766	61,820
18	385	Indu Meas / Reg Sta Equp	52,351		909,094	53,164		962,258	337,878
19	387	Other equipment	365		8,016	365		8,381	1,597
20	Total Distribution Plant		1,187,061	(10,826)	20,637,648	1,280,163	(25,156)	21,892,656	22,071,857
22	*General Plant*								
23	390	Structures & Improvements	98,538		969,249	98,538		1,067,786	2,987,256
24	391	Office Furniture & Equipment	161,536		1,276,776			1,276,776	(40,574)
25	391C	Computer equipment	14,928		24,880	24,149		49,029	371,605
26	392	Transportation Equipment	150,561		1,181,374	161,361		1,342,735	51,941
27	393	Stores Equipment	3,905		29,440	4,572		34,012	34,535
28	394	Tools, Shop & Garage Equipment	37,587		561,586	40,431		602,017	229,096
29	396	Power Operated	58,744		440,982	19,515		460,497	39,031
30	397	Communication Equipment	16,363		195,389	16,380		211,769	33,808
31	398	Miscellaneous Equipment	982		2,772	982		3,753	10,965
32	301	Intangible plant, organization	0		0	0		0	22,107
33	389	Land & Land Rights	0		0	0		0	572,424
34		Total General Plant	543,145	0	4,682,449	365,927	0	5,048,376	4,312,192
36		Less: Acquisition	(116,637)	0	(2,963,858)	(116,637)	0	(3,080,494)	(295,069)
37		Total Plant in Service	$1,613,569	($10,826)	$22,356,239	$1,529,454	($25,156)	$23,860,537	$26,088,980
38		Less: Clearing, Charged to NY	(188,077)			(188,077)			
39			$1,425,492			$1,341,376			26,103,255

WP2_C

Valley Energy, Inc. (PA)
Rate Case with Fully Projected Future Test Year 2026
Workpaper 2 to Schedule C
Future O&M
Years 2025 and 2026

Line	Dept.	Account	*rType22*	*rAcct25*	*rFTY25* Total 2025	*rFPFTY26* Total 2026
1	**PAYROLL - DIRECT LABOR**					
2	LABOR OPER SUPR & ENG	870.01	Labor	870	103,788	111,597
3	LABOR MAINS & SERV EXP	874.01	Labor	874	136,278	190,232
4	LABOR MEAS & REG STAT EXP	875.01	Labor	875	35,758	39,433
5	LABOR IND/CM MTR/REG MNT	876.01	Labor	876	31,539	35,807
6	LABOR MEAS & REG CITY GATE	877.01	Labor	877	6,288	6,955
7	LABOR MTR/HSE REG EXP	878.01	Labor	878	60,218	66,449
8	LABOR CUST INSTALL EXP	879.01	Labor	879	72,453	78,992
9	LABOR OQ TRAINING	880.01	Labor	880	20,603	27,547
10	LABOR MAINT SUPV & ENG	885.01	Labor	885	15,514	16,064
11	LABOR STURCTURES & IMPR	886.01	Labor	886	7,488	5,944
12	LABOR MAINT OF MAIN	887.01	Labor	887	36,769	42,609
13	LABOR MEAS & REG STAT EQUIP	889.01	Labor	889	20,343	17,755
14	LABOR MAINT. INDUST. M&R STATION	890.01	Labor	890	8,837	9,983
15	LABOR MAINT CITY GATE STAT	891.01	Labor	891	1,715	1,948
16	LABOR MAINT OF SERVICE	892.01	Labor	892	20,480	25,608
17	LABOR MAINT MTR & HSE REG	893.01	Labor	893	29,166	23,379
18	LABOR METER READING EXP	902.01	Labor	902	9,734	6,097
19	LABOR CUST REC/COLLECTIONS	903.01	Labor	903	214,654	226,152
20	LABOR ADMINISTRATION	920.01	Labor	920	276,347	293,409
21	LABOR GENERAL PLT MAINTENANCE	932.01	Labor	932	8,168	8,075
22	**Total Direct Labor**				**1,116,140**	**1,234,034**
23						
24	TRANSP OPER SUPR & ENG	870.02	Trans	870	8,447	8,700
25	TRANSP MAINS & SERVICE EXP	874.02	Trans	874	30,734	31,656
26	TRNSP MEAS & REG STAT EXP	875.02	Trans	875	8,638	8,897
27	TRANS IND/CM/MTR/REG/MNT	876.02	Trans	876	4,480	4,614
28	TRANSP MEAS & REG CITY GATE	877.02	Trans	877	2,640	2,719
29	TRANSP MTR/HSE REG EXP	878.02	Trans	878	8,833	9,098
30	TRANSP CUST INSTALL EXP	879.02	Trans	879	11,297	11,636
31	TRANSP OQ TRAINING	880.02	Trans	880	136	24
32	TRANSP MAINT SUPV & ENG	885.02	Trans	885	3,271	3,369
33	TRANSP MAINT STRUCTURES & IMPR	886.02	Trans	886	653	673
34	TRANSP MAINT OF MAIN	887.02	Trans	887	5,210	5,366
35	TRANSP MAINT MEAS/REG STAT EQ	889.02	Trans	889	1,461	1,505
36	TRANSP MAINT INDUS M&R STAT	890.02	Trans	890	212	218
37	TRANSP MAINT CITY GATE STAT	891.02	Trans	891	756	779
38	TRANSP MAINT OF SERVICE	892.02	Trans	892	7,657	7,887
39	TRANSP MAINT MTR HSE REG	893.02	Trans	893	2,134	2,198
40	TRANS METER READING EXP	902.02	Trans	902	2,499	2,574
41	TRANSP CUST REC/COLLECTIONS	903.02	Trans	903	3,923	4,041
42	TRANSP ADMINSTRATION	920.02	Trans	920	18,770	19,333
43	TRANS MAINT GENERAL PLANT	932.02	Trans	932	1,518	1,564
44	**Total Trans. Exp**				**123,269**	**126,851**
45						

WP2_C

Valley Energy, Inc. (PA)
Rate Case with Fully Projected Future Test Year 2026
Workpaper 2 to Schedule C
Future O&M
Years 2025 and 2026

Line	Dept.	Account	*rType22*	*rAcct25*	*rFTY25* Total 2025	*rFPFTY26* Total 2026
46	C&T OH OPER SUPR & ENG	870.03	OH	870	26,794	29,264
47	C&T OH MAINS & SERVICE EXP	874.03	OH	874	35,181	49,885
48	C&T OH MEAS & REG STAT EXP	875.03	OH	875	9,231	10,341
49	C&T OH IND/CM MTR/REG MNT	876.03	OH	876	8,142	9,390
50	C&T OH CITY GATE MEAS/REG STAT	877.03	OH	877	1,623	1,824
51	C&T OH MTR/HSE REG EXP	878.03	OH	878	15,546	17,425
52	C&T OH CUST INSTALL EXP	879.03	OH	879	18,704	20,714
53	C&T OH OQ TRAINING	880.03	OH	880	5,319	1,226
54	C&T OH MAINT SUPV & ENG	885.03	OH	885	4,005	4,213
55	C&T OH MAINT STRUCTURES & IMPR	886.03	OH	886	1,933	1,559
56	C&T OH MAINT OF MAIN	887.03	OH	887	9,492	11,174
57	C&T OH MAINT M&R STAT EQUIP	889.03	OH	889	5,252	4,656
58	C&T OH MAINT INDUST M&R STATION E	890.03	OH	890	2,281	2,618
59	C&T OH MAINT CITY GATE STAT	891.03	OH	891	443	511
60	C&T OH MAINT SERVICES EXP	892.03	OH	892	5,287	6,715
61	C&T OH MAINT MTR & HSE REG	893.03	OH	893	7,529	6,131
62	C&T OH METER READING EXP	902.03	OH	902	2,513	1,599
63	C&T OH CUST REC/COLLECTIONS	903.03	OH	903	55,414	59,305
64	C&T OH ADMINSTRATION	920.03	OH	920	71,341	76,942
65	C&T OVHD GENERAL PLANT	923.03	OH	920	2,109	2,118
66	**Total C&T OH**				**288,139**	**317,608**
67						
68	VE OH OPER SUPR & ENG	870.05	OH	870	100,001	109,223
69	VE OH MAINS & SERVICE EXP	874.05	OH	874	131,306	186,186
70	VE OH MEAS & REG STAT EXP	875.05	OH	875	34,453	36,913
71	VE OH IND/CM/MTR/REG MNT EXP	876.05	OH	876	30,388	34,862
72	VE OH CITY GATE MEAS & REG	877.05	OH	877	6,059	6,475
73	VE OH MTR/HSE REG EXP	878.05	OH	878	58,021	63,918
74	VE OH CUST INSTALL EXP	879.05	OH	879	69,810	76,507
75	VE OH OQ TRAINING	880.03	OH	880	19,851	4,509
76	VE OH MAINT SUPV & ENG	885.05	OH	885	14,948	15,723
77	VE OH MAINT STRUCTURES & IMPR	886.05	OH	886	7,215	2,498
78	VE OH MAINT OF MAIN	887.05	OH	887	35,428	41,703
79	VE OH MAINT M&R STAT EQUIP	889.05	OH	889	19,601	8,839
80	VE OH MAINT. INDUSTR. M&R STATION	890.05	OH	890	8,515	9,482
81	VE OH MAINT CITY GATE STAT	891.05	OH	891	1,652	1,907
82	VE OH MAINT OF SERVICE	892.05	OH	892	19,733	25,063
83	LABOR OH MAINT MTR & HSE REG	893.05	OH	893	28,102	7,931
84	VE OH METER READING EXP	902.05	OH	902	9,379	2,522
85	VE OH CUST REC/COLLECTIONS	903.05	OH	903	206,823	285,238
86	VE OH ADMINISTRATION	920.05	OH	920	266,265	287,169
87	OH MAINT PLANT	932.05	OH	932	7,870	5,527
88	**Total VE Labor OH**				**1,075,419**	**1,212,194**
89						
90						
91	FUEL (COMPANY USE)	842.10	Other	842	21,130	20,347
92	DISTRIB LOAD DISPATCHING	871.45	Mat	871	6,763	7,101
93	MAT & SUP MAINS & SERV EXP	874.45	Mat	874	32,675	32,675
94	CALL CENTER EXPENSE	874.50	Other	874	74,285	76,514
95	TOOLS, EQUIPMENT & MAINTENANCE	874.99	Mat	874	10,029	10,330
96	MAT/SUP MEAS & REG STAT EXP	875.45	Mat	875	10,207	10,513
97	MAT & SUP IND/CM/MTR/REG/MNT	876.45	Mat	876	7,968	9,164
98	MAT/SUP CITYGATE MEAS/REG STA	877.45	Mat	877	13,637	14,046
99	MAT & SUP MTR/HSE REG EXP	878.45	Mat	878	1,634	1,683
100	MAT/SUP CUST INSTALL EXP	879.45	Mat	879	920	947
101	MAT/SUP OQ TRAINING	880.45	Mat	880	8,526	1,491
102	RENTS - DISTRIBUTION EXPENSE	881.45	Mat	881	6,222	6,669
103	MAT/SUP MAINT STRUCTURE/IMPR	886.45	Mat	886	9,176	9,451
104	MAT/SUPP MAINT OF MAIN	887.45	Mat	887	31,010	31,940
105	MAT/SUP MAINT M&R STAT EQUIP	889.45	Mat	889	18,998	19,568
106	MAT/SUP MAINT M&R INDUST EQUIP	890.45	Mat	890	3,718	3,830
107	MAT/SUP MAINT CITY GATE STAT	891.45	Mat	891	3,323	7,616
108	MAT/SUP MAINT OF SERVICES	892.45	Mat	892	5,440	5,604
109	MAT/SUPP MAINT MTR & HSE REG	893.45	Mat	893	13,945	14,364
110						

WP2_C

Valley Energy, Inc. (PA)
Rate Case with Fully Projected Future Test Year 2026
Workpaper 2 to Schedule C
Future O&M
Years 2025 and 2026

Line	Dept.	Account	rType22	rAcct25	rFTY25 Total 2025	rFPFTY26 Total 2026
111	MAT/SUPP METER READING EXP	902.45	Mat	902	3,981	4,100
112	NISC BILLING	903.25	Other	903	111,397	112,891
113	MAT/SUP CUST REC/COLLECTIONS	903.45	Mat	903	29,837	30,732
114	DOLLAR ENERGY FUND EXPENSES	903.55	Other	903	5,927	5,927
115	BAD DEBT EXPENSE	904.00	Other	904	50,495	54,348
116	MAT/SUP MISC CUST ACCT EXP	905.45	Mat	905	21,492	21,492
117	INFORMATION/INSTRUCTIONAL EXP	909.45	Mat	909	12,774	13,157
118	ADVERTISING EXPENSES	913.45	Mat	913	2,057	2,098
119						
120	MAT/SUP ADMINISTRATIVE	920.45	Mat	920	68	69
121	GENERAL OFFICE SUPPLIES & EXP	921.00	Other	921	12,054	12,054
122	MEAL EXPENSES	921.40	Other	921	9,132	9,406
123	TRAVEL AND TRAINING	921.45	Other	921	40,834	42,059
124	COMMUNICATION EQUIP	921.50	Other	921	17,350	17,871
125	OUTSIDE SERVICES EMPLOYED	923.00	Other	923	25,452	26,215
126	AUDITOR FEES EXPENSE	923.25	Other	923	43,735	47,233
127	GCR EXPENSE	923.40	Other	923	3,321	3,487
128	ATTORNEY FEES EXPENSE	923.45	Other	923	8,152	8,560
129	INSURANCE ST OPENING BONDS	925.10	Other	925	500	376
130	PROPERTY INSURANCE EXPENSE	924.00	Other	924	36,257	41,699
131	INJURIES AND DAMAGES	925.00	Other	925	108,157	93,524
132	EMPLOYEE BENEFITS-DIRECT EXP.	926.45	Other	926	9,898	10,194
133	REGULATORY COMMISSION EXPENSES	928.00	Other	928	99,514	105,514
134	MISCELLANEOUS GENERAL EXPENSE	930.20	Other	930	28,363	30,751
135	LABOR - VOLUNTEER	930.21	Other	930	187	216
136	DUES/COMPANY MEMBERSHIPS	930.22	Other	930	16,791	17,295
137	COVID-Related	930CV	Other	930CV	-	-
138	DIRECTOR EXPENSE	930.25	Other	930	58,639	57,047
139	DIRECTOR EXP. - TRAVEL/TRAINING	930.45	Other	930	-	1,309
140	MAINT GENERAL PLANT	932.45	Mat	932	23,249	23,946
141	**Total Direct Expenses**				**1,059,219**	**1,077,423**
142					3,662,186	3,968,110
143					3,662,186	3,987,778
144					3,662,186	3,987,778
145						
146						
147			Other		781,570	794,837
148			Mat		277,649	282,586
149					1,059,219	1,077,423

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No. R-2025-3054393
	:	
Valley Energy, Inc.	:	
	:	

VERIFICATION

I, Greg R. Meyer, hereby state that the facts above set forth in my Direct Testimony, OCA Statement No. 1, are true and correct to the best of my knowledge, information, and belief and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa.C.S. § 4904 (relating to unsworn falsification to authorities).

DATED: July 15, 2025

Signature: */s/ Greg R. Meyer*
Greg R. Meyer

Address: Brubaker & Associates, Inc.
16690 Swingley Ridge Road
Suite 140
Chesterfield, MO 63017

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
	)	
v.	)	**R-2025-3054392**
	)	
Wellsboro Electric Company	)	

Direct Testimony and Exhibit of

Greg R. Meyer

OCA Statement 1

On behalf of

Pennsylvania Office of Consumer Advocate

Date Served: July 15, 2025

BRUBAKER & ASSOCIATES, INC.

Project 11858

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
v.	)	**R-2025-3054392**
Wellsboro Electric Company	)	

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Direct Testimony of Greg R. Meyer

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EXHIBIT GRM-1 (WELLSBORO)

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
v.	)	**R-2025-3054392**
Wellsboro Electric Company	)	

Direct Testimony of Greg R. Meyer

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Greg R. Meyer. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q WHAT IS YOUR OCCUPATION?

A I am a consultant in the field of public utility regulation and a Senior Principal with the firm of Brubaker & Associates, Inc. ("BAI"), energy, economic and regulatory consultants.

Q PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A This information is included in Appendix A to my testimony.

Q ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?

A I am appearing on behalf of the Pennsylvania Office of Consumer Advocate ("OCA").

Q HAVE YOU TESTIFIED BEFORE THE PENNSYLVANIA PUBLIC UTILITY COMMISSION ("COMMISSION") IN PRIOR PROCEEDINGS?

A Yes, I have. I provided testimony in Docket R-2024-3046519 (Columbia Gas of Pennsylvania) on behalf of the OCA.

Q PLEASE GIVE A BRIEF OVERVIEW OF YOUR TESTIMONY.

A My testimony will provide a brief overview of the case and discuss various aspects of the revenue requirement of Wellsboro Electric Company ("Wellsboro" or "Company").

My silence in regard to any issue should not be construed as an endorsement of or acquiescence to Wellsboro's position.

CASE OVERVIEW AND WITNESS INTRODUCTION

Q PLEASE DESCRIBE THE RATE INCREASE THAT WELLSBORO FILED.

A On April 30, 2025, Wellsboro filed a Statement of Reason seeking approval to increase base rates by $2.9 million. Wellsboro filed the Direct Testimony of five witnesses. Wellsboro serves approximately 6,478 customers. Wellsboro uses a Fully Projected Future Test Year ("FPFTY") ending December 31, 2026, a Future Test Year ("FTY") ending December 31, 2025, and a Historical Test Year ("HTY") ending December 31, 2024. Wellsboro stated in its filing that it must seek a general increase in its rates to recover its costs and to earn a fair return on capital.

Q CAN YOU DESCRIBE THIS RATE FILING IN RELATION TO THE COMPANY'S PRIOR GENERAL RATE INCREASE FILINGS?

A Wellsboro has filed for general rate increases in 2016 and 2019, each of which resulted in a grant of a rate increase with an effective date somewhere near nine months of the filing date in each case.

Q PLEASE SUMMARIZE THE TESTIMONY OF OCA'S OTHER EXPERTS IN THIS PROCEEDING.

A The OCA's witnesses touch on most aspects of the Company's rate case.

- My testimony, OCA Statement 1, addresses the Company's proposed claims for its proposed increase in its revenue requirement based on the FPFTY 2026 and makes recommendations for reasonable adjustments to reflect appropriate and normalized revenues and expenses for ratemaking purposes.

- Mr. Christopher Walters, OCA Statement 2, addresses the appropriate capital structure for ratemaking, the Return on Equity ("ROE"), and the impact of the Company's claims for an additional 25 basis points for management performance and size adjustment on the ROE. Mr. Walters recommends a market-based ROE of 9.50%, which is the midpoint of his reasonable range of 9.00% to 10.00% based on the analytical methods he used. The negative adjustment to the Company's revenue requirement based on Mr. Walters' recommended ROE is reflected in the recommended revenue requirement increase presented in my testimony.

- Mr. Michael W. Deupree, OCA Statement 3, is the OCA's expert witness on cost-of-service studies, revenue allocation, and rate design. Mr. Deupree provides adjustments to the Company's allocated class cost of service study, recommendations regarding proposed revenue allocation and rate design for the customer charge.

- Ms. LeeAnn Wise, OCA Statement 4, is the OCA's expert witness on quality of customer service issues, including customer payment fees, security deposits, and payment plans. Ms. Wise recommends that the Company eliminate the $3.95 processing fee charged to customers who pay their utility bills by credit card. Given this recommendation, the resulting increase to the revenue requirement will be reflected in my revenue requirement recommendation.

SUMMARY OF RECOMMENDATIONS

Q PLEASE SUMMARIZE YOUR CONCLUSIONS AND RECOMMENDATIONS.

A My conclusions and recommendations are as follows:

1. I recommend that Wellsboro's annualized revenues be increased.
2. I recommend a reduction to Wellsboro's annualized payroll expense.
3. I recommend an adjustment to the non-labor expenses charged to Accounts 920 and 932.
4. I recommend a reduction to Wellsboro's expenses related to Advertising and Lobbying.
5. I raise a concern about the apparent mismatch between the revenues and expenses related to the purchased power adjustment clause.

Q DO YOU BELIEVE AN INCREASE IN WELLSBORO'S REVENUES OF APPROXIMATELY $2.9 MILLION WILL RESULT IN JUST AND REASONABLE RATES FOR WELLSBORO'S CUSTOMERS?

A No. I believe that the base rate increase proposed by Wellsboro is overstated. I have prepared Table GRM-1 (Wellsboro) that shows the adjustments I am proposing that reduces the revenue increase sought by Wellsboro by a total of $690,664. With my adjustments, and the adjustments recommended by OCA Witness Walters (ROE) and OCA Witness Wise (credit card payment fees), Table GRM-1 (Wellsboro) shows that Wellsboro is only entitled to a $2,208,724 revenue requirement increase.

Table GRM-1 (Wellsboro)

OCA Revenue Requirment Adjustments

Line	Description	Amount
1	Company Proposed Revenue Requirement Increase[1]	$ 2,899,388
	OCA Adjustments:	
2	Return on Equity	$ (405,756)
3	Rate Revenue	$ (28,210)
4	Labor	$ (139,491)
5	Acct 920 and 932	$ (152,463)
6	Sponsorship and Lobbying	$ (2,389)
7	Credit Card Fee	$ 37,645
8	Total OCA Adjustments	$ (690,664)
9	OCA Proposed Revenue Requirement Increase	$ 2,208,724

Source:
[1]OCA-I-1 Attachment A (Schedule A-D) Tab "C1."

REVENUES

Q HAVE YOU REVIEWED THE LEVEL OF ANNUALIZED REVENUES PROPOSED BY WELLSBORO FOR INCLUSION IN THIS RATE CASE?

A Yes, I have.

Q DO YOU AGREE WITH THE LEVELS OF ANNUALIZED REVENUES INCLUDED IN WELLSBORO'S REVENUE REQUIREMENT?

A No. I believe Wellsboro has understated the Commercial and Industrial levels of revenues.

Q PLEASE EXPLAIN WHY YOU BELIEVE WELLSBORO HAS UNDERSTATED THE LEVEL OF COMMERCIAL REVENUES.

A The usage per customer (kilowatt-hour ("kWh") per customer) proposed by Wellsboro for the Commercial class is understated when compared to a 10-year average of usage from the 2015-2024 Company annual reports. I have prepared Table GRM-2 (Wellsboro) below to show the levels of Commercial usage from different time periods and the usage level proposed by Wellsboro.

Table GRM-2 (Wellsboro)

Commercial Usage Analysis

Time Period	Usage (kWh) per Customer
5-Year Average[1]	24,605
10-Year Average[1]	25,920
15-Year Average[1]	26,369
Company Proposed FPFTY[2]	25,358

Sources:
[1]Calculated based on Company Annual reports from 2010 to 2024.
[2]Company Schedule B3.

As can be seen from Table GRM-2 (Wellsboro), the Commercial usage levels proposed by Wellsboro are lower than the 10- and 15-year historical usage levels experienced. I recommend using the 10-year usage patterns for the Commercial class to annualize revenues. The table also shows that the 10- and 15-year usage patterns are close to each other and greater than the five-year usage level. Overall, this indicates that the recent years have had milder weather and a longer time period of annualization is warranted.

Q WHAT IS THE COMMERCIAL REVENUE ADJUSTMENT IMPACT FROM YOUR PROPOSED USAGE PER CUSTOMER?

A Utilizing the 10-year usage per customer results in an increase in annualized Commercial revenues of $21,854. I would note that my adjustment to increase Commercial revenues recognizes the effects of uncollectible expense. The adjustment to Commercial usage per customer is calculated in Exhibit GRM-1 (Wellsboro), page 3, and the impact is shown on Exhibit GRM-1 (Wellsboro), page 2. The energy proposed for Commercial customers is shown on Exhibit GRM-1 (Wellsboro), page 4.

Q FINALLY, DO YOU BELIEVE WELLSBORO'S INDUSTRIAL REVENUES ARE ALSO UNDERSTATED?

A Yes, I do. I have prepared Table GRM-3 (Wellsboro) to show the levels of Industrial usage from different time periods and the usage level proposed by Wellsboro.

Table GRM-3 (Wellsboro)

Industrial Usage Analysis

Time Period	Usage (kWh) per Customer
5-Year Average[1]	2,129,794
10-Year Average[1]	2,364,313
15-Year Average[1]	2,608,906
Company Proposed FPFTY[2]	2,057,407

Sources:
[1]Calculated based on Company Annual reports from 2010 to 2024.
[2]Company Schedule B3.

As can be seen from Table GRM-3 (Wellsboro) above, the Industrial usage levels proposed by Wellsboro are lower than the five-, 10-, and 15-year historical usage levels experienced. I recommend using the 10-year usage patterns for the Industrial class to annualize revenues. The 10-year usage is a conservative recommendation that captures some effects of milder weather while recognizing that weather has been abnormal in recent years.

Q WHAT IS THE INDUSTRIAL REVENUE ADJUSTMENT IMPACT FROM YOUR PROPOSED USAGE PER CUSTOMER?

A Utilizing the 10-year usage per customer results in an increase in annualized Industrial revenues of $6,211. I would note that my adjustment to increase Industrial revenues recognizes the effects of uncollectible expense. The adjustment to Industrial usage per

customer is calculated in Exhibit GRM-1 (Wellsboro), page 3, and the impact is shown on Exhibit GRM-1 (Wellsboro), page 2. The energy proposed for Industrial customers is shown on Exhibit GRM-1 (Wellsboro), page 4.

Summing the two rate class revenue adjustments results in a total Wellsboro increase to Wellsboro's revenues of $28,065. This results in a decrease to revenue requirement of $28,210. This is shown on Exhibit GRM-1 (Wellsboro), page 2.

PAYROLL EXPENSE

Q HAVE YOU REVIEWED THE LEVEL OF PAYROLL EXPENSE INCLUDED IN WELLSBORO'S REVENUE REQUIREMENT?

A Yes, I have.

Q DO YOU BELIEVE THE LEVEL OF PAYROLL EXPENSE INCLUDED IN WELLSBORO'S REVENUE REQUIREMENT REPRESENTS A REASONABLE LEVEL?

A No. I believe Wellsboro has overstated the level of payroll expenses for the FPFTY 2026. Wellsboro is proposing to increase payroll expense by approximately 20%[1] over the payroll level recorded in the HTY 2024.

[1]Percent Change of Schedule C1-1 Total Operating & Maintenance Expense between FPFTY 2026 and HTY 2024.

Q PLEASE DISCUSS THE PROCESS YOU UTILIZED TO ANNUALIZE WELLSBORO'S PAYROLL EXPENSES.

A I increased the HTY 2024 level of payroll by 4% to a reasonable level of FTY 2025 payroll expenses. I then applied a 4% payroll increase to the FTY 2025 level of payroll expenses to reflect a reasonable FPFTY 2026 annualized level of payroll expenses.

Q WHY DID YOU CHOSE A 4% PAYROLL INCREASE FIGURE?

A It is my experience that a typical range for annual payroll increases is between 3.5% to 4% per year. Therefore, I chose 4% to annualize Wellsboro's payroll expense.

Q WHAT WAS THE EFFECT OF YOUR PAYROLL ANNUALIZATION?

A My annualized level of payroll expenses resulted in a reduction of payroll expenses of $129,798. This results in a decrease to the revenue requirement of $139,491. My proposed payroll expenses are shown on Exhibit GRM-1 (Wellsboro), pages 19 through 24. The impact of this adjustment is shown on Exhibit GRM-1 (Wellsboro), page 2.

NON-LABOR OPERATION & MAINTENANCE ("O&M") EXPENSES

Q HAVE YOU REVIEWED WELLSBORO'S O&M EXPENSES?

A Yes, I have. In reviewing Wellsboro's expenses, I have noticed that the projections for Account 920 (Administrative and General ("A&G") Salaries) and Account 932 (Maintenance of General Property) were much greater than recent history would suggest appropriate.

Q WAS THE GROWTH IN EXPENSE ASSOCIATED WITH THESE ACCOUNTS ADDRESSED IN WELLSBORO'S TESTIMONY?

A Yes, but not on the account level. The testimony from Wellsboro witness Byron Farnsworth Jr. addressed A&G expense generally, which includes both accounts, stating "our Administrative & General Expenses and our Customer Account and Collection Expenses have increased."[2]

Q WHAT DID YOU FIND WITH RESPECT TO THE NON-LABOR EXPENSES ASSOCIATED WITH ACCOUNT 920 A&G SALARIES?

A In reviewing the response to Data Request I&E-RE-16-D, I found a shocking lack of explanation for the growth requested in this account. The request asked the Company to supply detailed explanations for the growth in this account's expense from 2023 through the projections for FPFTY 2026. Wellsboro merely referenced Mr. Farnsworth's testimony and exhibits as well as the testimony of Wellsboro witness Jill Campbell. Neither of these testimonies provides a specific analysis of the expense booked to the A&G salaries account.

Additionally, this response provides a breakdown of the expense between labor and non-labor categories. I have excerpted this below.

A.

	2023	2024	2025	2026
Labor	301,608	355,049	401,562	426,497
Overhead	351,031	402,852	468,335	484,732
Transportation	-	-	-	-
Material	-	-	-	-
	652,639	757,901	869,897	911,229

[2] *See* Direct Testimony of Byron Farnsworth, Jr. at page 6, lines 9-10.

As can be seen in this breakdown, the Company proposes to increase the non-labor portion by $81,880 over the HTY 2024 level. This represents a growth of 20.3%.

Q WHAT IS YOUR CONCERN WITH THIS PROJECTED GROWTH IN THIS ACCOUNT?

A My concern is that this forecasted growth has not been justified by specific and concrete evidence. If we are asking customers to pay for an $81,880 increase in additional A&G overhead cost, Wellsboro should provide convincing reasons why it is necessary.

Q WHAT DO YOU PROPOSE FOR THIS ACCOUNT?

A Since I address salaries elsewhere in this testimony, I will only address the overhead component of Account 920. I believe that absent justification, no increase in the overhead should be allowed. This will reduce the Company's proposed expense by $81,880.

Q WHAT DID YOU FIND WITH RESPECT TO THE EXPENSES ASSOCIATED WITH ACCOUNT 932 MAINTENANCE OF GENERAL PROPERTY?

A For Account 932, in reviewing the response to Data Request I&E-RE-20-D, the Company has proffered a string of assertions to the increasing cost, but no breakdown as to how much each item contributes to the overall growth we see in the account:

> The projected 84.0% increase in expenses from HTY 2024 to FTY 2025 is primarily due to the return to normal operations following the completion of construction, along with planned investments in key areas. IT and cybersecurity costs are expected to

> rise as the Company continues to strengthen system security and maintain critical software and support services. Utility expenses are expected to increase with the full facility back in use, leading to higher consumption of gas, water, and related services. Grounds maintenance will also return to normal levels, including increased lawn care now that construction is complete and full property upkeep has resumed. In addition, FTY 2025 includes preparation for a typical winter season, with a corresponding increase in snow plowing costs. The increase also accounts for scheduled blacktop maintenance, specifically sealing half of the complex as part of a planned alternating-year maintenance cycle.

Additionally, the Company provided a breakdown of the expense between labor and non-labor categories in response to Data Request I&E-RE-21-D that I have excerpted below.

A.

	2023	2024	2025	2026
Labor	50,565.49	11,363.62	12,378.00	12,746.00
OH	-	-	5,643.00	5,979.00
Other	62,014.46	60,822.23	114,826.00	114,826.00
	112,579.95	72,185.85	132,847.00	133,551.00

As can be seen in this breakdown, the Company proposes to increase the non-labor portion by $59,983 over the HTY 2024 level. This represents a growth of 98.6%.

Q WHAT IS YOUR CONCERN WITH THIS PROJECTED GROWTH IN THIS ACCOUNT?

A My concern is that this forecasted growth has not been justified by specific and concrete evidence. If we are asking customers to pay for a $59,983 increase in additional non-labor general plant maintenance cost, Wellsboro should provide convincing reasons why it is necessary.

Q WHAT DO YOU PROPOSE FOR THIS ACCOUNT?

A Since I address salaries elsewhere in this testimony, I will only address the overhead and other components of Account 932. I believe that absent justification, no increase in the overhead and other non-labor cost should be allowed. This will reduce the Company's proposed expense by $59,983.

My adjustments to Accounts 920 and 932 result in a decrease to expense of $141,863 and decrease revenue requirement by $152,463. My adjusted expense levels are shown on Exhibit GRM-1 (Wellsboro), pages 23 and 24, and the impacts of these adjustments are shown on Exhibit GRM-1 (Wellsboro), page 2.

ADVERTISING AND LOBBYING

Q HAVE YOU PERFORMED A REVIEW OF WELLSBORO'S ADVERTISING AND LOBBYING EXPENSE?

A Yes, I have. In response to Data Request I&E-RE-10-D and OCA-VII-20, Wellsboro provided the Company's Advertising and Lobbying expenses that were included in the FPFTY. Wellsboro is proposing to include $2,191 and $32 in the FPFTY for Advertising and Lobbying expenses, respectively.

Q DO YOU BELIEVE THAT THE ABOVE LEVELS OF ADVERTISING AND LOBBYING EXPENSES IS APPROPRIATE TO INCLUDE IN THIS CASE?

A No, customers should not have to pay for Advertising and Lobbying expenses that are not necessary or beneficial to providing safe and reliable service. These types of activities mentioned are solely for burnishing the reputation of the Company.

Q WHAT IS YOUR RECOMMENDATION REGARDING ADVERTISING AND LOBBYING EXPENSES?

A I recommend that these expenses be removed from the revenue requirement. This adjustment would lower the revenue requirement by $2,389. My adjusted expense levels can be seen on Exhibit GRM-1 (Wellsboro), pages 10 and 11. The impact of my adjustments can be seen on Exhibit GRM-1 (Wellsboro), page 2.

REVENUE/EXPENSE PURCHASED POWER ADJUSTMENT ("PPA")

Q HAVE YOU REVIEWED THE REVENUE REQUIREMENT ADJUSTMENT PROPOSED BY WELLSBORO TO REMOVE PURCHASED POWER EXPENSE FROM THE REVENUES AND EXPENSES OF WELLSBORO?

A Yes, I have.

Q DO YOU HAVE ANY CONCERNS WITH THE ADJUSTMENTS PROPOSED BY WELLSBORO?

A Yes. The PPAs proposed by Wellsboro create a significant revenue requirement impact for the distribution rate case. Specifically, Wellsboro proposes to reduce revenues associated with purchase power by approximately $6.9 million.[3] In addition, Wellsboro proposes a purchase power expense adjustment of approximately $5.7 million.[4] These PPAs create an increase to revenue requirement of approximately $1.2 million due to the difference in the revenue and expense PPAs.

[3]As shown on Company Schedule C1, Per Books Total Revenue $13,158,392 minus Distribution Only Revenues of $6,255,065 equals $6,903,327.

[4]Company Schedule C1 at line 13.

Q MUST THESE TOTALS EQUAL?

A Not necessarily. However, there is an approximate 20% difference between the revenue adjustment and the expense adjustment proposed by Wellsboro. This is a significant difference between expense and revenue recognition.

Q HOW WOULD YOU LIKE TO PROCEED IN THIS RATE CASE?

A I would propose that Wellsboro be given the opportunity to explain the difference between the revenue and expense adjustments. Parties can then review these explanations and determine if they are reasonable. At this point in time, I am not proposing an adjustment to set the revenue and expense adjustments equal to each other. I reserve the right to propose an adjustment in later testimonies.

Q ARE YOU AWARE OF THE OTHER UTILITIES (CITIZENS' ELECTRIC COMPANY OF LEWISBURG ("CITIZENS") AND VALLEY ENERGY, INC. ("VALLEY")) HAVING SIMILAR ADJUSTMENTS?

A Citizens does not have this concern, as Citizens adjusted its revenues and expenses by the same totals. Valley has a similar problem as Wellsboro, but the revenue requirement effect is opposite of that effect for Wellsboro.

OTHER ADJUSTMENTS

Q ARE YOU REFLECTING OTHER ADJUSTMENTS IN YOUR RECOMMENDED REVENUE INCREASE?

A Yes. In Exhibit GRM-1 (Wellsboro), page 2, and in Table GRM-1 (Wellsboro), I reflect the adjustments to the Company's revenue requirement increase recommended by OCA Witnesses Walters and Wise, in OCA Statements 2 and 4, respectively.

Q PLEASE EXPLAIN HOW YOU ADDRESS OCA WITNESS WALTERS' ADJUSTMENT.

A OCA Witness Walters recommends a market-based ROE of 9.50%, which is the midpoint of his reasonable range of 9.00% to 10.00% based on the analytical methods he used. Applying Mr. Walters' recommended ROE results in a negative adjustment to the Company's revenue requirement claim by $405,756.

Q PLEASE EXPLAIN HOW YOU ADDRESS OCA WITNESS WISE'S ADJUSTMENT.

A OCA Witness Wise recommends that the Company eliminate the $3.95 processing fee charged to customers who pay their utility bills by credit card. The total annual revenue that the Company collects in these fees from customers and then forwards to a third-party vendor is $35,029. Applying Ms. Wise's recommendation results in a positive adjustment of $37,645 to the Company's claimed revenue requirement increased.

CONCLUSION

Q DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A Yes, it does.

QUALIFICATIONS OF GREG R. MEYER

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Greg R. Meyer. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q PLEASE STATE YOUR OCCUPATION.

A I am a consultant in the field of public utility regulation and a Senior Principal with the firm of Brubaker & Associates, Inc. ("BAI"), energy, economic and regulatory consultants.

Q PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A I graduated from the University of Missouri in 1979 with a Bachelor of Science Degree in Business Administration, with a major in Accounting. Subsequent to graduation I was employed by the Missouri Public Service Commission. I was employed with the Commission from July 1, 1979 until May 31, 2008.

I began my employment at the Missouri Public Service Commission as a Junior Auditor. During my employment at the Commission, I was promoted to higher auditing classifications. My final position at the Commission was an Auditor V, which I held for approximately ten years.

As an Auditor V, I conducted audits and examinations of the accounts, books, records and reports of jurisdictional utilities. I also aided in the planning of audits and investigations, including staffing decisions, and in the development of staff positions in

which the Auditing Department was assigned. I served as Lead Auditor and/or Case Supervisor as assigned. I assisted in the technical training of other auditors, which included the preparation of auditors' workpapers, oral and written testimony.

During my career at the Missouri Public Service Commission, I presented testimony in numerous electric, gas, telephone and water and sewer rate cases. In addition, I was involved in cases regarding service territory transfers. In the context of those cases listed above, I presented testimony on all conventional ratemaking principles related to a utility's revenue requirement. During the last three years of my employment with the Commission, I was involved in developing transmission policy for the Southwest Power Pool as a member of the Cost Allocation Working Group.

In June of 2008, I joined the firm of Brubaker & Associates, Inc. as a Consultant. Since joining the firm, I have presented testimony and/or testified in the state jurisdictions of Arkansas, Florida, Idaho, Illinois, Indiana, Iowa, Kentucky, Maryland, Missouri, Montana, New Mexico, Ohio, Utah, Washington, Wisconsin and Wyoming. I have also appeared and presented testimony in Alberta and Nova Scotia, Canada. In addition, I have filed testimony at the Federal Energy Regulatory Commission ("FERC"). These cases involved addressing conventional ratemaking principles focusing on the utility's revenue requirement. The firm Brubaker & Associates, Inc. provides consulting services in the field of energy procurement and public utility regulation to many clients including industrial and institutional customers, some utilities and, on occasion, state regulatory agencies.

More specifically, we provide analysis of energy procurement options based on consideration of prices and reliability as related to the needs of the client; prepare rate,

feasibility, economic, and cost of service studies relating to energy and utility services; prepare depreciation and feasibility studies relating to utility service; assist in contract negotiations for utility services, and provide technical support to legislative activities.

In addition to our main office in St. Louis, the firm also has branch offices in Corpus Christi, Texas; Louisville, Kentucky and Phoenix, Arizona.

537471

Table GRM-1 (Wellsboro)

OCA Revenue Requirment Adjustments

Line	Description	Amount
1	Company Proposed Revenue Requirement Increase[1]	$ 2,899,388
	OCA Adjustments:	
2	Return on Equity	$ (405,756)
3	Rate Revenue	$ (28,210)
4	Labor	$ (139,491)
5	Acct 920 and 932	$ (152,463)
6	Sponsorship and Lobbying	$ (2,389)
7	Credit Card Fee	$ 37,645
8	Total OCA Adjustments	$ (690,664)
9	OCA Proposed Revenue Requirement Increase	$ 2,208,724

Source:
[1]OCA-I-1 Attachment A (Schedule A-D) Tab "C1."

Wellsboro Electric Company

Change Log of OCA Adjustments to Revenue Requirement

Line	Issue	Changed Cells	Starting Revenue Requirement Increase (1)	Ending Revenue Requirement Increase (2)	OCA Adjustment (3)	Notes and Sources (4)
1	Return on Equity	Changed Cell E13 on Tab "C1-2" to 9.5%	$ 2,899,388	$ 2,493,632	$ (405,756)	See Mr. Christopher Walters, OCA Statement 2
2	Rate Revenue - Commercial	On Tab "B3-1", added 101,281 to Cell F7, 134 to Cell G7, 621,892 to Cell H7, and 154 to Cell I7.	$ 2,493,632	$ 2,471,666	$ (21,967)	See Mr. Greg Meyer, OCA Statement 1; See Adjustment Schedule 1 for the calculation of additional usage added
3	Rate Revenue - Industrial	On Tab "B3-1", added 4,777,876 to Cell J7. Changed Cell J51 to reference Cell J7 instead of J52.	$ 2,471,666	$ 2,465,422	$ (6,243)	See Mr. Greg Meyer, OCA Statement 1; See Adjustment Schedule 1 for the calculation of additional usage added
4	Labor	On Tab "WP1_C", changed all Cells with values in Rows with Type of "Labor" from Account 580 to Account 932 to reflect a 4% increase in total labor for each year from 2024 in relation to their proportion of expense to the total in Row 206.	$ 2,465,422	$ 2,325,931	$ (139,491)	See Mr. Greg Meyer, OCA Statement 1
5	Account 920	Subtracted $81,880 from Cell U151 on Tab "WP1_C"	$ 2,325,931	$ 2,237,936	$ (87,995)	See Mr. Greg Meyer, OCA Statement 1
6	Account 932	On Tab "WP1_C", changed all Cells with values in Rows with Type of "OH" or "Other" from Account 932 to reflect a proportion of a $59,983 decrease in relation to their proportion of total Account 932 non-labor expense.	$ 2,237,936	$ 2,173,468	$ (64,468)	See Mr. Greg Meyer, OCA Statement 1
7	Sponsorship and Lobbying	Subtracted $32 from Cell I185 and $2,191 from Cell I144 on Tab "WP1_C"	$ 2,173,468	$ 2,171,079	$ (2,389)	See Mr. Greg Meyer, OCA Statement 1
8	Credit Card Fee	Added $35,029 from Cell I119 on Tab "WP1_C"	$ 2,171,079	$ 2,208,724	$ 37,645	See Ms. LeeAnn Wise, OCA Statement 4
9				OCA Total Adjustments	$ (690,664)	

Wellsboro Electric Company

Commercial Usage per Customer Adjustments

Line	Description	Sch 3 - NRS	Sch 3 - NRH	Sch 4 - CS	Sch 4 - CSH	Total
		(1)	(2)	(3)	(4)	(5)
1	Company Proposed FPFTY Sales (kWh)[1]	4,732,166	6,256	29,056,715	7,216	33,802,353
2	Company Proposed FPFTY Average Customers[1]	938	1	392	1	1,332
3	Company Proposed Usage per Customer (Line 1 ÷ Line 2)					25,377
4	OCA Proposed Usage per Customer[2]					25,920
5	OCA Adjustment to Usage per Customer (Line 4 - Line 3)					543
6	OCA Proposed Additional Usage[3]	101,281	134	621,892	154	723,461

Industrial Usage per Customer Adjustments

Line	Description	Sch 5 - IS
7	Company Proposed FPFTY Sales (kWh)[1]	26,746,293
8	Company Proposed FPFTY Average Customers[1]	13
9	Company Proposed Usage per Customer (Line 7 ÷ Line 8)	2,005,972
10	OCA Proposed Usage per Customer[2]	2,364,313
11	OCA Adjustment to Usage per Customer (Line 10 - Line 9)	358,341
12	OCA Proposed Additional Usage (Line 8 x Line 11)	4,777,876

Sources and Notes:

[1]Company Schedule B3-1.

[2]Ten year average of sales divided by average customers from 2020 to 2024 Annual Reports.

[3]Calculated based on the proportion of usage as shown on Company Schedule B3-1.

B3-1

Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026
Billing Units, Rates And Revenue At Present Rates
Fully Projected Future Test Year 2026

Line		Sch. 1- RS	Sch. 2- RSAE	Sch. 3- NRS	Sch. 3- NRH	Sch. 4- CS	Sch. 4- CSH	Sch. 5- IS	Sch. 6- MSL	Sch. 7- POL	Sch. 8- EU	Total
1						**BILLING UNITS**						
2	kWh Sales	44,812,773	397,781	4,833,447	6,390	29,678,607	7,370	31,524,169	0	0	102,572	111,363,111
3												
4	Number of Bills	61,910	350	11,258	12	4,704	12	160			48	78,454
5	Average Monthly Bills	5,159	29	938	1	392	1	13			4	6,538
6												
7						**Annual Billing Units- Public Lighting and Street Lighting, Fully Projected Future Test Year 2026**							
8	MV 20000 lumens											
9	LED 50 OH								1,788	5,064		6,852
10	LED 50 UG											
11	LED 50 UG Col											
12	LED 70 OH								1,307	4,381		5,688
13	LED 70 UG											
14	LED 140 OH									24		24
15	LED 140 UG											
16									3,095	9,469		12,564
17						**RATES AND CHARGES**						
18						**Tariff Rates**						
19	Customer Charge	$12.00	$12.00	$12.22	$12.22	$32.03	$45.81	$85.00				
20												
21	Energy Block 1	$0.05864	$0.05127	$0.07630	$0.08469	$0.02268	$0.06628	$0.02078	$10.76	$8.81	$0.08732	
22	Energy Block 2							$0.00130	$4.12	$8.33		
23									$11.06	$11.06		
24									$16.03	$16.03		
25									$4.69	$8.89		
26									$11.62	$11.62		
27									$5.81	$10.02		
28									$12.75	$12.75		
29												
30	Block 1 kWh = Demand X							130				
31	Demand Block 1					$6.60		$10.00				
32												
33						**COMPUTATION OF REVENUE**						
34	Customer Charge Revenue	742,920	4,200	137,573	147	150,669	550	13,600	0	0	0	1,049,658
35												
36	Distribution kWh Revenue	2,627,821	20,394	368,792	541	673,111	488	209,031	13,496	81,371	8,957	4,004,003
37	Distribution Demand Revenue					712,800		663,600				1,376,400
38	*Volumetric Distribution Reve.*	2,627,821	20,394	368,792	541	1,385,911	488	872,631	13,496	81,371	8,957	5,380,403
39	**Total Distribution Revenue**	$3,370,741	$24,594	$506,365	$688	$1,536,580	$1,038	$886,231	$13,496	$81,371	$8,957	$6,430,061
40		*3,357,674*	*24,303*	*490,178*		*1,507,523*		*880,700*				
41						**BILLING UNITS- DETAIL**						
42	Forecast Customers 2025	5,149	29	928	1	388	1	13			4	6,514
43	Customers added (lost)	10		10		4						24
44	Forecast Customers 2026	5,159	29	938	1	392	1	13	0	0	4	6,538
45	Block 1 kWh Sales	44,812,773	397,781	4,732,166	6,256	29,056,715	7,216	8,626,800	0	0	102,572	87,742,280
46	Block 2 kWh Sales							22,897,369				22,897,369
47								26,746,293				
48												
49												
50	From Sch B2-1											
51	Annual Use Per Customer	8,686	13,638	5,044	6,256	74,124	7,216	1,903,840			25,643	
52												
53	Block 1 kW Demand- Same as 2024					108,000		66,360				174,360
54												

C1

Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026

Net Operating Income And Rates of Return
HY 2024, FTY 2025 and FPFTY 2026
Answer to 52 Pa. Code 53.52 c[1]

Line	Description	HY 2024		Present Rates 12/31/2025	(A) Present Rates Fully Projected 12/31/2026	Proposed Rates Fully Projected 12/31/2026	(B) Proposed Rates Fully Projected 12/31/2020	(A)-(B) Change from Prior Order
		Per Books	Distribution Only	Distribution Only	Distribution Only	Distribution Only	Settlement Prior	
1	**REVENUE**							
2	Residential	$6,829,521	$3,190,200	$3,388,802	$3,395,335	$5,078,907	$3,261,637	$133,698
3	Commercial and industrial	5,657,570	2,642,167	2,887,490	2,930,902	4,126,437	2,708,336	222,567
4	Lighting	100,851	95,243	94,867	94,867	113,787	90,112	4,755
5	Sales for resale	17,863	8,957	8,957	8,957	12,171	9,732	(776)
6	Rounding						200	(200)
7	Electric operating revenue	12,605,805	5,936,568	6,380,115	6,430,061	8,638,785	6,070,017	360,044
8	Other revenue, net	318,497	318,497	320,653	327,777	327,777	116,459	211,318
9	Under (over) Collections	234,090	0	0	0	0	0	0
10	Total Revenue	13,158,392	6,255,065	6,700,768	6,757,838	8,966,562	6,186,476	571,362
11	*Annual kWH*	*97,019,287*	*97,019,287*	*104,333,284*	*111,363,111*	*111,363,111*	*107,825,923*	*(10,806,636)*
12	**EXPENSES**				Increase	2,208,724		
13	Purchased electricity	5,720,438						
14	Distribution	1,334,849	1,334,849	1,561,937	1,549,966	1,549,966	1,285,908	264,058
15	Customer accounting & collection expen	929,410	929,410	1,050,953	1,084,250	1,084,250	649,803	434,447
16	Sales expense, Public relations	3,171	3,171	19,727	7,531	7,531	8,915	(1,384)
17	Administrative & general expenses	1,264,200	1,264,200	1,486,637	1,452,412	1,452,412	929,641	522,771
18	Total Operating expenses	9,252,068	3,531,630	4,119,254	4,094,159	4,094,159	2,874,267	1,219,892
19								
20	Depreciation expense	1,335,247	1,335,247	1,844,192	1,939,404	1,939,404	1,331,977	607,427
21	Taxes other than income	814,557	394,406	420,575	423,522	594,586	377,878	45,644
22	Rate case expense amortization						108,667	(108,667)
23	Total Expenses	11,401,872	5,261,283	6,384,021	6,457,084	6,628,148	4,692,789	1,764,296
24								
25	Net operating income before income t	1,756,519	993,782	316,747	300,754	2,338,414	1,493,687	(1,192,933)
26								
27	Income tax expense	175,781	(44,590)	(60,908)	(62,828)	525,895	447,548	(510,377)
28	NET UTILITY OPERATING INCOME (LOSS) (A)	$1,580,738	$1,038,371	$377,654	$363,582	$1,812,519	$1,046,139	($682,557)
29						0.0701781		
30	RATE BASE (B)		$26,163,779	$26,224,141	$25,827,423	$25,827,423	$14,653,172	$11,510,607
31	RATE OF RETURN ON RATE BASE (A / B)		3.97%	1.44%	1.41%	7.02%	7.14%	

C1-2

Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026

Support Sheet No. 2- Summary of Cost of Capital and Fair Rate of Return Based upon a Hypothetical Ratemaking Capital Structure
12/31/2025 and 12/31/2026

Line	Type of Capital	Ratios (1)	Cost Rate		Weighted Cost Rate
1	Long-Term Debt	51.06%	4.850%		2.47641%
2	Short-Term Debt				0.00%
3	Total Debt	51.06%			2.48%
4					
5	Preferred Stock				0.00000%
6	Common Equity	48.94%	9.50%	9.2300%	4.64930%
7	Total	100.00%	9.31%		7.12571%
8				Target ROR	7.13%
9					
10	[1] Recommended hypothetical capital structure ratios as discussed in direct testimony.				
11					2,208,724

WP_C1

Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026
Expenses By Account and By Type
Year 2013, HY 2024, FTY 2025 and FPFTY 2026

				Annuals Totals, Detailed by Type			
Line	Account	#	Type	2023	2024	2025	2026
1	PPower-Power Purchases			8,108,800	6,587,193	7,834,837	9,111,330
2	Total Power Purchased			8,108,800	6,587,193	7,834,837	9,111,330
3							
4	580.01-Oper.Superv. Eng-Labor	580	Labor	-	4,043		-
5	580.02-Oper.Superv. Eng-OH	580	OH	-	4,078		-
6	580.03-Oper.Superv. Eng-Transp	580	Trans/Mat				-
7	582.01-Station Exp-Labor	582	Labor				-
8	582.02-Station Exp-OH	582	Trans/Mat	-	-		-
9	583.01-OH Line Exp-Labor	583	Labor	(2,379)	(1,766)	3,980	3,706
10	583.02-OH Line Exp-OH	583	OH	3,064	2,535	1,814	1,922
11	583.05-OH Line Exp-Misc	583	Trans/Mat				-
12	585.01-Street/Signal Light-Labor	585	Labor	-	127	178	165
13	585.02-Street/Signal Light-OH	585	OH	675	19	81	85
14	585.04-Street/Signal Light-Matl	585	Trans/Mat				-
15	586.01-Meter Exp-Labor	586	Labor	19,146	21,287	26,220	24,402
16	586.02-Meter Exp-OH	586	OH	14,498	15,697	11,725	12,422
17	586.03-Meter Exp-Transp	586	Trans/Mat				-
18	586.05-Meter Exp-Misc	586	Other	-	-	500	500
19	587.01-Cust Install Exp-Labor	587	Labor	-	109	178	165
20	587.02-Cust Install Exp-OH	587	OH	-	98	81	85
21	587.04-Cust Install Exp-Matl	587	Trans/Mat				-
22	588.00 Misc Distr Exps	588	Other	1,084	(1,389)	6,800	6,800
23	588.01 Labor - Misc Distr Expens	588	Labor	37,840	29,489	61,875	57,895
24	588.02 OH - Misc Distr Exp	588	OH	48,793	40,264	62,211	62,486
25	588.03-Misc Distr Exp-Transp	588	Trans/Mat				-
26	588.11 Labor - Genl Type Mtg - C	588	Labor	7,872	11,084	8,467	7,928
27	588.12 OH - Genl Type Mtg	588	OH	5,099	8,757	9,349	9,351
28	588.13-Misc Dist Exp-Genl Mtg Ti	588	Trans/Mat				-
29	588.20-Misc Dist Exp-Outside Tra	588	Other	7,534	9,606	15,000	15,000
30	588.21-Misc Dist Exp-Outside Tra	588	Labor	5,846	10,141	11,506	10,714
31	588.22-Misc Dist Exp-Outside Tra	588	OH	1,559	2,482	5,245	5,556
32	588.23-Misc Dist Exp-Outside Tra	588	Trans/Mat	-	699		-
33	588.31 Labor - On Call - Standby	588	Labor	12,639	12,129	14,799	13,251
34	588.32-Misc Dist Exp-On Call Sta	588	OH	3,575	3,097	6,746	6,873
35	588.40 Safety Mtgs & Training	588	Other	4,268	6,339		-
36	588.41 Labor - Safety Mtgs & Trai	588	Labor	22,120	28,265	39,910	37,251
37	588.42 OH - Safety Mtgs & Tra	588	OH	12,442	12,981	38,515	39,156
38	588.90 Misc Dist-Staking Dept-To	588	Other				-
39	589.00-Distr rents	589	Other	30,717	32,950	35,300	35,300
40						-	-
41	**Total operations**			236,392	253,121	360,478	351,012

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Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026
Expenses By Account and By Type
Year 2013, HY 2024, FTY 2025 and FPFTY 2026

				Annuals Totals, Detailed by Type			
Line	Account	#	Type	2023	2024	2025	2026
42							-
43	590.01-Maint, Supv & Eng-Labor	590	Labor	37,403	41,204	41,076	38,585
44	590.02-Maint, Supv & Eng-OH	590	OH	48,308	56,671	59,695	59,121
45	590.03-Maint, Supv & Eng-Transp	590	Trans/Mat				-
46	591.01-Maint of Structures-Labor	591	Labor	792	-		-
47	591.02-Maint of Structures-OH	591	Trans/Mat	1,056	-		-
48	592.01-Maint of Station Equip-Lat	592	Labor	678	1,255	1,869	1,740
49	592.02-Maint of Station Equip-OH	592	OH	1,863	1,621	2,702	126,752
50	592.03-Maint of Station Equip-Tra	592	Trans/Mat				-
51	592.04- Matl/Supp Inv-Maint Sta	592	Other				(110,119)
52	592.11- Substation Inspect In-hou	592	Labor	3,156	334		-
53	592.00-Substation Insp-In House-	592	Other				-
54	593.00 Maint OH Lines	593	Other				-
55	593.01 Labor - OH Line Maintena	593	Labor	140,138	175,692	202,337	188,417
56	593.02 OH - OH Line Mainten	593	OH	126,049	129,933	101,742	107,224
57	593.03-Maint of OH Lines-Transp	593	Trans/Mat				-
58	593.04 Matl/Supp Inv-Maint Ove	593	Trans/Mat	767	-		-
59	593.10 Maint OH Lines - Brush C	593	Other	407,770	444,468	480,457	480,457
60	593.11 OH Line-Tree Trim-In-H	593	Labor	17,691	15,547	16,743	15,592
61	593.12-Tree Trim-In House-Trans	593	Trans/Mat			7,633	8,087
62	593.13-Tree Trimming-In House-C	593	Labor				-
63	593.21-Overhead Line Inspection	593	Trans/Mat	38,954	6,362	24,679	25,411
64	593.22-OH Line Insp-Line Crew-C	593	OH	8,264	1,470	11,251	11,920
65	593.30 Maint Of OH-Working Off	593	Other				-
66	593.31 Labor - Maint Lines - Wor	593	Labor	355	-		-
67	593.32 OH - Maint Lines - Work C	593	OH	(355)	-		-
68	593.40 Maint Of OH Lines - Meals	593	Other	919	359	1,500	1,500
69	593.50-Maint O/H Line-Major Stor	593	Other	27,765	31,980		-
70	593.51 Labor - Maint Lines - Majo	593	Labor	30,707	26,331	53,377	49,169
71	593.52 OH Lines- Major	593	Other	6,092	4,524	15,216	16,120
72	593.60 Maint Lines-Major Storm-E	593	Labor				-
73	593.80 Maint O/H - Testing-Tools	593	Other	24,438	26,984	40,500	40,500
74	593.90 Maint-Special Equip-Repa	593	Other				-
75	593.91-Special Equip Insp-Labor	593	Labor	7,214	6,137	9,367	8,723
76	593.92-Special Equipment Inspec	593	Trans/Mat			4,270	4,524

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Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026
Expenses By Account and By Type
Year 2013, HY 2024, FTY 2025 and FPFTY 2026

				Annuals Totals, Detailed by Type			
Line	Account	#	Type	2023	2024	2025	2026
77	594.01-Maint of UG Lines-Labor	594	Labor	1,751	4,369	4,353	4,054
78	594.02-Maint of UG Lines-OH	594	OH	1,588	2,645	1,984	2,102
79	594.03-Maint of UG Lines-Transp	594	Trans/Mat				-
80	594.04-Maint of UG Lines-Matl	594	Trans/Mat				-
81	594.05-Maint UG Lines- Misc	594	Other			-	-
82	594.11- UG Inspect In-hours	594	Labor	1,847	113	150	141
83	594.12- UG Inspect OH	594	OH			69	73
84	594.90- Maint UG Lines PA ON	594	Other	23,250	23,079	33,500	33,500
85	595.01-Maint of Line Xfrnrs-Labor	595	Labor	1,742	3,059	3,347	3,117
86	595.02-Maint of Line Xfrnrs-OH	595	OH	949	1,358	1,526	1,617
87	595.03-Maint of Line Xfrnrs-Trans	595	Trans/Mat				-
88	595.05-Maint Line Xfrnrs-Misc	595	Other				-
89	595.80-Maint of Line Xfrnrs-Disp	595	Trans/Mat	2,987	10,115	3,000	3,000
90	596.01-Maint of Street Lights-Lab	596	Labor	1,700	962	623	580
91	596.02-Maint of Street Lights-OH	596	OH	1,291	650	284	301
92	596.04-Maint of Street Lights-Mat	596	Trans/Mat				-
93	597.00-Maint of Meters	597	Labor	30,912	25,037		-
94	597.01-Maint of Meters-Labor	597	Labor	32,568	31,514	34,412	32,045
95	597.02-Maint of Meters-OH	597	OH	9,842	7,010	15,688	16,620
96	597.03-Maint of Meters-Transp	597	Trans/Mat				-
97	597.04-Maint of Meters-Matl	597	Trans/Mat	(529)	8		-
98	597.05-Maint of Meters-Misc	597	Trans/Mat				-
99	597.41-Maintenance of Meters-TV	597	Labor			623	580
100	597.42-Maintenance of Meters-TV	597	OH			27,484	27,501
101	597.44-Maint TWACS Meters	597	Other	2,674	937	-	-
102							-
103	**Total Maint**			1,042,595	1,081,729	1,201,459	1,198,954
104							
105	**Total Distr Exp**			1,278,988	1,334,849	1,561,937	1,549,966
106				-	-		

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Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026
Expenses By Account and By Type
Year 2013, HY 2024, FTY 2025 and FPFTY 2026

Line	Account	#	Type	Annuals Totals, Detailed by Type 2023	2024	2025	2026
107	**CustS ACCOUNTING & COLLECTING Exp**						-
108	902.01-Meter Reading Exp-Labor	902	Labor	10,767	12,359	10,936	10,184
109	902.02-Meter Reading Exp-OH	902	OH	9,042	9,416	4,986	5,283
110	902.03-Meter Reading Exp-Trans	902	Trans/Mat				-
111	903.00-Cust Rec & Coll Exp	903	Other	5,411	6,868	5,000	5,000
112	903.01-Cust Rec & Collect Exp-La	903	Labor	201,641	203,082	215,355	208,407
113	903.02-Cust Rec & Collect Exp-O	903	OH	260,964	276,153	310,965	352,459
114	903.03-Cust Rec & Collect Exp-Tı	903	Trans/Mat				-
115	903.20-Cust Rec Exp-Seminars-M	903	Other			500	500
116	903.30-Cust Rec Exp-Postage	903	Other	40,256	43,390	43,375	43,375
117	903.40-Cust Coll-Credit Check	903	Other	858	801	900	900
118	903.45-Cust Coll-EGS Monthly Sv	903	Other	3,260	4,252	3,600	3,600
119	903.50-Cust Rec Exp-Billing Supp	903	Other	496	1,153	3,200	3,200
120	903.60-Cust Rec Exp-NISC Comp	903	Other	128,903	135,388	163,600	163,600
121	903.81-Cust Rec Exp-Collect-Lab	903	Labor	69,880	70,302	75,899	73,379
122	903.82-Cust Rec Exp-Collecting-(	903	OH	88,320	92,349	107,690	109,963
123	903.83-Cust Rec Exp-Collect-Tra	903	Trans/Mat				-
124	903.90-Cust Rec Exp-Delinq	903	Other			500	500
125	903.91-Cust Rec Exp-Delinq-Labo	903	Labor	36,011	36,526	39,266	37,573
126	903.92-Cust Rec Exp-Delinq-OH	903	OH	36,950	37,371	45,181	46,326
127	903.05-Cust Rec Exp-Delinq-Misc	903	Other				-
128	904.00-Uncollectable Accounts	904	Other	-	-	20,000	20,000
129						-	-
130	**Total Cust accounting & collecting**			892,757	929,410	1,050,953	1,049,221
131						**0**	
132	**SALES PROMOTION Exp**						-
133	908.00-Cust Assist-Exp	908	Other	295	-	1,000	1,000
134	908.51-Cust Assist-Energy Audit-I	908	Labor	1,735	180	156	146
135	908.52-Cust Assist-Energy Audit-I	908	OH			71	76
136	908.05-Cust Assist-Energy Audit-I	908	Other				-
137	909.00-Cust Service Info-Misc	909	Other	314	800	16,000	6,000
138	913.00-Advertising Exp	913	Other	1,738	2,191	2,500	309
139						-	-
140	**Total Sales Promotion Exp**			4,082	3,171	19,727	9,722
141							-

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Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026
Expenses By Account and By Type
Year 2013, HY 2024, FTY 2025 and FPFTY 2026

Line	Account	#	Type	Annuals Totals, Detailed by Type 2023	2024	2025	2026
142	**ADMINISTRATIVE & Genl Exp**						-
143	920.00-A&G Salaries	920	Labor	22,250	11,954	9,000	8,140
144	920.01-A&G Salaries-Labor	920	Labor	258,765	292,156	325,262	319,071
145	920.02-A&G Salaries-OH	920	OH	351,031	402,852	468,335	402,852
146	920.03-A&G Salaries-Transp	920	Trans/Mat				-
147	920.40-A&G-President-CEO	920	Labor	5,377	6,176	12,000	10,853
148	920.50-A&G-V-P Fin Adminis	920	Labor	8,392	26,510	17,600	13,566
149	920.60-A&G-V-P Eng Oper	920	Labor	2,059	3,188	15,000	13,566
150	920.70-A&G- Staff	920	Labor	4,766	15,065	22,700	20,530
151	921.00-Off Supp & Exp	921	Other	9,054	12,730	11,540	11,540
152	921.10-Off Supp & Exp-Utilities	921	Other	4,803	5,835	6,060	6,060
153	921.40-Off Exp-Subs/Membership	921	Other	4,042	5,186	3,400	3,400
154	921.50-Off Exp-Off Supp	921	Other	6,413	8,823	23,260	23,260
155	921.60-Off Exp-WECO Telephone	921	Other	31,375	47,437	49,500	49,500
156	921.70-Off Exp-Dispatch Telepho	921	Other	79,441	89,963	90,800	90,800
157	921.90-Off Exp-Misc	921	Other	9,938	8,780	20,060	20,060
158	921.99-Off Exp-Working Capital C	921	Other	(83,141)	(65,853)	(81,613)	(94,910)
159	923.00-Outside Svc Empl	923	Other	26,301	24,421	29,325	29,325
160	923.10-Outside Svc Empl-Auditor	923	Other	31,951	34,886	34,000	34,000
161	923.20-Outside Svc Empl-Engine	923	Other	75	610	5,000	5,000
162	923.30-Outside Svc Empl-Attorne	923	Other	21,703	16,158	25,000	25,000
163	923.90-Outside Services Employe	923	Other	7,859	61,040	61,200	61,200
164	924.00-Property Insurance	924	Other	51,268	53,098	61,410	61,410
165	925.00-Injuries & Damages	925	Other				-
166	926.11-Employee Pen Ben-Health	926	OH	-	-		-
167	926.20-Empl Pen Ben-Postret He	926	OH				-
168	926.70-Employee Pen Ben-Life In	926	OH				-
169	926.99-Employee Pen Ben-SERP	926	OH				-
170	928.00-Regulatory Commission E	928	Other	32,144	42,985	43,000	43,000
171	928.01-Rate Case Exp	928	Other	36,222	-		110,393
172	930.00-Directors Exp	930	Other	101,167	83,257	95,851	106,681
173	930.11-Misc Gen Exp-GPS Map L	930	Other	-	-		-
174	930.20-Misc Gen Exp-GPS Map-L	930	Labor	3,074	-	3,100	2,804
175	930.21-Misc Gen Exp-GPS Map-(	930	Other				-
176	930.22-Misc Gen Exp-GPS Mapp	930	OH				-
177	930.24-Misc Gen Exp-GPS Mapp	930	Other				-
178	930.25-Misc Gen Exp-Covid Expe	930	Other	-	-		-
179	930.30-Misc Gen Exp- Misc	930	Other	1,113	1,147	800	768

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Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026
Expenses By Account and By Type
Year 2013, HY 2024, FTY 2025 and FPFTY 2026

Line	Account	#	Type	Annuals Totals, Detailed by Type 2023	2024	2025	2026
180	931.00-Rents	931	Other	2,442	3,611	2,200	2,200
181	932.00-Maint of Genl Property	932	Other	48,827	40,021	86,976	43,790
182	932.01-Maint of Genl Property-La	932	Labor	46,719	9,859	10,814	10,070
183	932.02-Maint of Genl Property-OH	932	OH			4,930	2,625
184	932.10-Maint of Genl Property-Ofl	932	Other	11,518	6,205	11,000	5,538
185	932.11-Maint Genl Prop-Off Bldg-	932	Labor	3,217	-		-
186	932.12-Maint Genl Prop-Off Bldg-	932	OH				-
187	932.20-Maint Genl-Communicatio	932	Other	-	-	500	252
188	932.21-Maint Genl-Comm Equip-l	932	Labor				-
189	932.22-Maint Genl-Comm Equip-(	932	OH				-
190	932.30-Maint Gen Property-Plant	932	Other	422	12,688	12,550	6,319
191	932.31-Maint Gen Prop-Plant Bld	932	Labor	630	1,505	1,564	1,457
192	932.32-Maint Gen Prop-Plant Bld	932	OH			713	381
193	932.41-Maint Gen Prop-Apt Hous	932	Labor				-
194	932.42-Maint Gen Prop-Apt Hous	932	OH				-
195	932.70-Maint Gen Office Equip	932	Other	1,248	1,908	3,800	1,913
196	932.05-Maint Genl Property- Misc	932	Other	-	-	-	-
197						1,486,637	1,452,444
198	**Total Administrative & Genl Exp**			1,142,464	1,264,200	1,486,637	1,452,444
199	Detail, adjusted for WC Claim						0
200	**Total Operating Exp**			3,318,291	3,531,630	4,119,254	4,061,353
201	From OM			*3,318,291*	*3,531,630*	*4,119,254*	*4,332,745*
202	Adjustments				*='C:\Users\hgorm\Documen*	*='C:\Users\hgorm\Documents Laptop\CTE-25\WEL-25\WEL-2*	
203	Working Capital claim			83,141	65,853	81,613	94,910
204	Rate case Exp			-	-		
205				3,401,431	3,597,484	4,200,867	4,156,263
206	From OM						
207	From C1-1			-	1,294,042		
208	Differrence			3,401,431	2,303,442		
209							
210							
211	Labor		Labor	1,087,018	1,135,323	1,294,042	1,227,966
212	OH		OH	1,033,810	1,109,508	1,301,063	1,411,131
213	Trans/Mat		Trans/Ma	43,235	17,184	39,582	41,022
214	Other		Other	1,154,228	1,269,615	1,484,567	1,414,040
215	WC		WC	-	-	-	-
216				3,318,291	3,531,630	4,119,254	4,094,159

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Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026
Expenses By Account and By Type
Year 2013, HY 2024, FTY 2025 and FPFTY 2026

Line	Account	#	Type	E&O 2025	Office 2025	Admin & Misc 2025	C&T Payroll 2025	Union Payroll 2025	Transportation 2025
1	PPower-Power Purchases								
2	Total Power Purchased								
3									
4	580.01-Oper.Superv. Eng-Labor	580	Labor						
5	580.02-Oper.Superv. Eng-OH	580	OH						
6	580.03-Oper.Superv. Eng-Transp	580	Trans/Mat						
7	582.01-Station Exp-Labor	582	Labor						
8	582.02-Station Exp-OH	582	Trans/Mat						
9	583.01-OH Line Exp-Labor	583	Labor					2,937	1,043
10	583.02-OH Line Exp-OH	583	OH					1,814	
11	583.05-OH Line Exp-Misc	583	Trans/Mat						
12	585.01-Street/Signal Light-Labor	585	Labor					131	47
13	585.02-Street/Signal Light-OH	585	OH					81	
14	585.04-Street/Signal Light-Matl	585	Trans/Mat						
15	586.01-Meter Exp-Labor	586	Labor	500			-	18,979	6,741
16	586.02-Meter Exp-OH	586	OH				-	11,725	
17	586.03-Meter Exp-Transp	586	Trans/Mat						
18	586.05-Meter Exp-Misc	586	Other	500					
19	587.01-Cust Install Exp-Labor	587	Labor				-	131	47
20	587.02-Cust Install Exp-OH	587	OH				-	81	
21	587.04-Cust Install Exp-Matl	587	Trans/Mat						
22	588.00 Misc Distr Exps	588	Other	6,800					
23	588.01 Labor - Misc Distr Expens	588	Labor				34,092	20,501	7,282
24	588.02 OH - Misc Distr Exp	588	OH				49,545	12,666	
25	588.03-Misc Distr Exp-Transp	588	Trans/Mat						
26	588.11 Labor - Genl Type Mtg - O	588	Labor				5,503	2,187	777
27	588.12 OH - Genl Type Mtg	588	OH				7,997	1,352	
28	588.13-Misc Dist Exp-Genl Mtg Ti	588	Trans/Mat						
29	588.20-Misc Dist Exp-Outside Tra	588	Other	15,000					
30	588.21-Misc Dist Exp-Outside Tra	588	Labor				-	8,490	3,016
31	588.22-Misc Dist Exp-Outside Tra	588	OH				-	5,245	
32	588.23-Misc Dist Exp-Outside Tra	588	Trans/Mat						
33	588.31 Labor - On Call - Standby	588	Labor					10,920	3,879
34	588.32-Misc Dist Exp-On Call Sta	588	OH					6,746	
35	588.40 Safety Mtgs & Training	588	Other						
36	588.41 Labor - Safety Mtgs & Trai	588	Labor				10,698	21,556	7,656
37	588.42 OH - Safety Mtgs & Tra	588	OH	9,650			15,547	13,318	
38	588.90 Misc Dist-Staking Dept-To	588	Other						
39	589.00-Distr rents	589	Other	35,300					
40									
41	**Total operations**			67,750	-	-	123,381	138,860	30,487

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Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026
Expenses By Account and By Type
Year 2013, HY 2024, FTY 2025 and FPFTY 2026

Line	Account	#	Type	E&O 2025	Office 2025	Admin & Misc 2025	C&T Payroll 2025	Union Payroll 2025	Transportation 2025
42									
43	590.01-Maint, Supv & Eng-Labor	590	Labor				41,076		
44	590.02-Maint, Supv & Eng-OH	590	OH				59,695		
45	590.03-Maint, Supv & Eng-Transp	590	Trans/Mat						
46	591.01-Maint of Structures-Labor	591	Labor						
47	591.02-Maint of Structures-OH	591	Trans/Mat						
48	592.01-Maint of Station Equip-Lat	592	Labor					1,379	490
49	592.02-Maint of Station Equip-OH	592	OH	1,850				852	
50	592.03-Maint of Station Equip-Tra	592	Trans/Mat						
51	592.04- Matl/Supp Inv-Maint Sta	592	Other						
52	592.11- Substation Inspect In-hou	592	Labor						
53	592.00-Substation Insp-In House-	592	Other						
54	593.00 Maint OH Lines	593	Other						
55	593.01 Labor - OH Line Maintena	593	Labor					149,305	53,032
56	593.02 OH - OH Line Mainten	593	OH	9,500				92,242	
57	593.03-Maint of OH Lines-Transp	593	Trans/Mat						
58	593.04 Matl/Supp Inv-Maint Ove	593	Trans/Mat						
59	593.10 Maint OH Lines - Brush C	593	Other	480,457					
60	593.11 OH Line-Tree Trim-In-H	593	Labor					12,355	4,388
61	593.12-Tree Trim-In House-Trans	593	Trans/Mat					7,633	
62	593.13-Tree Trimming-In House-C	593	Labor						
63	593.21-Overhead Line Inspection	593	Trans/Mat				-	18,211	6,468
64	593.22-OH Line Insp-Line Crew-C	593	OH				-	11,251	
65	593.30 Maint Of OH-Working Off	593	Other						
66	593.31 Labor - Maint Lines - Worl	593	Labor						
67	593.32 OH - Maint Lines - Work C	593	OH						
68	593.40 Maint Of OH Lines - Meals	593	Other	1,500					
69	593.50-Maint O/H Line-Major Stor	593	Other						
70	593.51 Labor - Maint Lines - Majo	593	Labor	20,000			-	24,629	8,748
71	593.52 OH Lines- Major	593	Other				-	15,216	
72	593.60 Maint Lines-Major Storm-E	593	Labor						
73	593.80 Maint O/H - Testing-Tools	593	Other	40,500					
74	593.90 Maint-Special Equip-Repa	593	Other						
75	593.91-Special Equip Insp-Labor	593	Labor					6,912	2,455
76	593.92-Special Equipment Inspec	593	Trans/Mat					4,270	

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Expenses By Account and By Type
Year 2013, HY 2024, FTY 2025 and FPFTY 2026

Line	Account	#	Type	E&O 2025	Office 2025	Admin & Misc 2025	C&T Payroll 2025	Union Payroll 2025	Transportation 2025
77	594.01-Maint of UG Lines-Labor	594	Labor				-	3,212	1,141
78	594.02-Maint of UG Lines-OH	594	OH				-	1,984	
79	594.03-Maint of UG Lines-Transp	594	Trans/Mat						
80	594.04-Maint of UG Lines-Matl	594	Trans/Mat						
81	594.05-Maint UG Lines- Misc	594	Other						
82	594.11- UG Inspect In-hours	594	Labor					111	39
83	594.12- UG Inspect OH	594	OH					69	
84	594.90- Maint UG Lines PA ON	594	Other	33,500					
85	595.01-Maint of Line Xfrnrs-Labor	595	Labor					2,470	877
86	595.02-Maint of Line Xfrnrs-OH	595	OH					1,526	
87	595.03-Maint of Line Xfrnrs-Trans	595	Trans/Mat						
88	595.05-Maint Line Xfrnrs-Misc	595	Other						
89	595.80-Maint of Line Xfrnrs-Disp	595	Trans/Mat	3,000					
90	596.01-Maint of Street Lights-Lab	596	Labor					460	163
91	596.02-Maint of Street Lights-OH	596	OH					284	
92	596.04-Maint of Street Lights-Mat	596	Trans/Mat						
93	597.00-Maint of Meters	597	Labor						
94	597.01-Maint of Meters-Labor	597	Labor					25,393	9,019
95	597.02-Maint of Meters-OH	597	OH					15,688	
96	597.03-Maint of Meters-Transp	597	Trans/Mat						
97	597.04-Maint of Meters-Matl	597	Trans/Mat						
98	597.05-Maint of Meters-Misc	597	Trans/Mat						
99	597.41-Maintenance of Meters-TV	597	Labor					460	163
100	597.42-Maintenance of Meters-TV	597	OH	27,200				284	
101	597.44-Maint TWACS Meters	597	Other						
102									
103	**Total Maint**			617,507	-	-	100,771	396,196	86,985
104									
105	**Total Distr Exp**			685,257	-	-	224,153	535,056	117,471
106									

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Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026
Expenses By Account and By Type
Year 2013, HY 2024, FTY 2025 and FPFTY 2026

Line	Account	#	Type	E&O 2025	Office 2025	Admin & Misc 2025	C&T Payroll 2025	Union Payroll 2025	Transportation 2025
107	**CustS ACCOUNTING & COLLECTING Exp**								
108	902.01-Meter Reading Exp-Labor	902	Labor					8,070	2,866
109	902.02-Meter Reading Exp-OH	902	OH					4,986	
110	902.03-Meter Reading Exp-Trans	902	Trans/Mat						
111	903.00-Cust Rec & Coll Exp	903	Other			5,000			
112	903.01-Cust Rec & Collect Exp-La	903	Labor				213,345	1,483	527
113	903.02-Cust Rec & Collect Exp-O	903	OH				310,049	916	
114	903.03-Cust Rec & Collect Exp-Tı	903	Trans/Mat						
115	903.20-Cust Rec Exp-Seminars-M	903	Other		500				
116	903.30-Cust Rec Exp-Postage	903	Other		43,375				
117	903.40-Cust Coll-Credit Check	903	Other		900				
118	903.45-Cust Coll-EGS Monthly Sv	903	Other		3,600				
119	903.50-Cust Rec Exp-Billing Supp	903	Other		3,200				
120	903.60-Cust Rec Exp-NISC Comp	903	Other	8,500	155,100				
121	903.81-Cust Rec Exp-Collect-Lab	903	Labor				73,281	1,932	686
122	903.82-Cust Rec Exp-Collecting-(	903	OH				106,497	1,193	
123	903.83-Cust Rec Exp-Collect-Tra	903	Trans/Mat						
124	903.90-Cust Rec Exp-Delinq	903	Other		500				
125	903.91-Cust Rec Exp-Delinq-Labo	903	Labor				27,351	8,792	3,123
126	903.92-Cust Rec Exp-Delinq-OH	903	OH				39,749	5,432	
127	903.05-Cust Rec Exp-Delinq-Misc	903	Other						
128	904.00-Uncollectable Accounts	904	Other		20,000				
129									
130	**Total Cust accounting & collecting**			8,500	227,175	5,000	770,272	32,804	7,202
131									
132	**SALES PROMOTION Exp**								
133	908.00-Cust Assist-Exp	908	Other		1,000				
134	908.51-Cust Assist-Energy Audit-I	908	Labor					115	41
135	908.52-Cust Assist-Energy Audit-I	908	OH					71	
136	908.05-Cust Assist-Energy Audit-I	908	Other						
137	909.00-Cust Service Info-Misc	909	Other		16,000				
138	913.00-Advertising Exp	913	Other		2,500				
139									
140	**Total Sales Promotion Exp**			-	19,500	-	-	186	41
141									

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Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026
Expenses By Account and By Type
Year 2013, HY 2024, FTY 2025 and FPFTY 2026

Line	Account	#	Type	E&O 2025	Office 2025	Admin & Misc 2025	C&T Payroll 2025	Union Payroll 2025	Transportation 2025
142	**ADMINISTRATIVE & Genl Exp**								
143	920.00-A&G Salaries	920	Labor			9,000			
144	920.01-A&G Salaries-Labor	920	Labor				322,262		3,000
145	920.02-A&G Salaries-OH	920	OH				468,335		
146	920.03-A&G Salaries-Transp	920	Trans/Mat						
147	920.40-A&G-President-CEO	920	Labor	12,000					
148	920.50-A&G-V-P Fin Adminis	920	Labor			17,600			
149	920.60-A&G-V-P Eng Oper	920	Labor	15,000					
150	920.70-A&G- Staff	920	Labor		22,700				
151	921.00-Off Supp & Exp	921	Other		5,540	6,000			
152	921.10-Off Supp & Exp-Utilities	921	Other			6,060			
153	921.40-Off Exp-Subs/Membership	921	Other		3,400				
154	921.50-Off Exp-Off Supp	921	Other		23,260				
155	921.60-Off Exp-WECO Telephone	921	Other	-		49,500			
156	921.70-Off Exp-Dispatch Telepho	921	Other	86,000		4,800			
157	921.90-Off Exp-Misc	921	Other		17,700	2,360			
158	921.99-Off Exp-Working Capital C	921	Other			(81,613)			
159	923.00-Outside Svc Empl	923	Other		3,925	25,400			
160	923.10-Outside Svc Empl-Auditor	923	Other			34,000			
161	923.20-Outside Svc Empl-Engine	923	Other	5,000					
162	923.30-Outside Svc Empl-Attorne	923	Other			25,000			
163	923.90-Outside Services Employe	923	Other			61,200			
164	924.00-Property Insurance	924	Other			61,410			
165	925.00-Injuries & Damages	925	Other						
166	926.11-Employee Pen Ben-Health	926	OH						
167	926.20-Empl Pen Ben-Postret He	926	OH						
168	926.70-Employee Pen Ben-Life In	926	OH						
169	926.99-Employee Pen Ben-SERP	926	OH						
170	928.00-Regulatory Commission E	928	Other			43,000			
171	928.01-Rate Case Exp	928	Other						
172	930.00-Directors Exp	930	Other			95,851			
173	930.11-Misc Gen Exp-GPS Map L	930	Other						
174	930.20-Misc Gen Exp-GPS Map-L	930	Labor	3,100					
175	930.21-Misc Gen Exp-GPS Map-(	930	Other						
176	930.22-Misc Gen Exp-GPS Mapp	930	OH						
177	930.24-Misc Gen Exp-GPS Mapp	930	Other						
178	930.25-Misc Gen Exp-Covid Expe	930	Other						
179	930.30-Misc Gen Exp- Misc	930	Other	800					

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Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026
Expenses By Account and By Type
Year 2013, HY 2024, FTY 2025 and FPFTY 2026

Line	Account	#	Type	E&O 2025	Office 2025	Admin & Misc 2025	C&T Payroll 2025	Union Payroll 2025	Transportation 2025
180	931.00-Rents	931	Other		2,200				
181	932.00-Maint of Genl Property	932	Other	11,500		75,476			
182	932.01-Maint of Genl Property-La	932	Labor					7,980	2,834
183	932.02-Maint of Genl Property-OH	932	OH					4,930	
184	932.10-Maint of Genl Property-Ofl	932	Other	11,000					
185	932.11-Maint Genl Prop-Off Bldg-	932	Labor						
186	932.12-Maint Genl Prop-Off Bldg-	932	OH						
187	932.20-Maint Genl-Communicatio	932	Other	500					
188	932.21-Maint Genl-Comm Equip-L	932	Labor						
189	932.22-Maint Genl-Comm Equip-(	932	OH						
190	932.30-Maint Gen Property-Plant	932	Other	12,550			-		
191	932.31-Maint Gen Prop-Plant Bld	932	Labor					1,154	410
192	932.32-Maint Gen Prop-Plant Bld	932	OH					713	
193	932.41-Maint Gen Prop-Apt Hous	932	Labor						
194	932.42-Maint Gen Prop-Apt Hous	932	OH						
195	932.70-Maint Gen Office Equip	932	Other		3,800				
196	932.05-Maint Genl Property- Misc	932	Other						
197				157,450	82,525	435,044	790,597	14,777	6,244
198	**Total Administrative & Genl Exp**			157,450	82,525	435,044	790,597	14,777	6,244
199	Detail, adjusted for WC Claim								
200	**Total Operating Exp**			851,207	329,200	440,044	1,785,022	582,823	130,959
201	From OM								
202	Adjustments			*5 Support\[WEL25 OpBudget2025.xlsx]Assumptions-Breakdown-All'!$I$357*					
203	Working Capital claim								
204	Rate case Exp								
205				851,207	329,200	440,044	1,785,022	582,823	130,959
206	From OM								
207	From C1-1								
208	Differrence								
209									
210									
211	Labor		Labor	50,600	22,700	26,600	727,608	342,044	124,490
212	OH		OH	48,200	-	-	1,057,414	195,449	-
213	Trans/Mat		Trans/Ma	3,000	-	-	-	30,114	6,468
214	Other		Other	749,407	306,500	413,444	-	15,216	-
215	WC		WC	-	-	-	-	-	-
216				851,207	329,200	440,044	1,785,022	582,823	130,959

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Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026
Expenses By Account and By Type
Year 2013, HY 2024, FTY 2025 and FPFTY 2026

Line	Account	#	Type	E&O 2026	Office 2026	Admin & Misc 2026	C&T Payroll 2026	Union Payroll 2026	Transportation 2026	Annual Totals, By Account 2023	2024	2025	2026
1	PPower-Power Purchases									8,108,800	6,587,193	7,834,837	9,111,330
2	Total Power Purchased									8,108,800	6,587,193	7,834,837	9,111,330
3													
4	580.01-Oper.Superv. Eng-Labor	580	Labor										
5	580.02-Oper.Superv. Eng-OH	580	OH										
6	580.03-Oper.Superv. Eng-Transp	580	Trans/Mat							-	8,121	-	-
7	582.01-Station Exp-Labor	582	Labor										
8	582.02-Station Exp-OH	582	Trans/Mat							-	-	-	-
9	583.01-OH Line Exp-Labor	583	Labor					2,762	944				
10	583.02-OH Line Exp-OH	583	OH					1,922					
11	583.05-OH Line Exp-Misc	583	Trans/Mat							686	770	5,794	5,628
12	585.01-Street/Signal Light-Labor	585	Labor					123	42				
13	585.02-Street/Signal Light-OH	585	OH					85					
14	585.04-Street/Signal Light-Matl	585	Trans/Mat							675	146	259	250
15	586.01-Meter Exp-Labor	586	Labor	452			-	17,850	6,100				
16	586.02-Meter Exp-OH	586	OH				-	12,422					
17	586.03-Meter Exp-Transp	586	Trans/Mat										
18	586.05-Meter Exp-Misc	586	Other	500						33,644	36,983	38,445	37,324
19	587.01-Cust Install Exp-Labor	587	Labor				-	123	42				
20	587.02-Cust Install Exp-OH	587	OH				-	85					
21	587.04-Cust Install Exp-Matl	587	Trans/Mat							-	206	259	250
22	588.00 Misc Distr Exps	588	Other	6,800									
23	588.01 Labor - Misc Distr Expens	588	Labor				32,024	19,282	6,589				
24	588.02 OH - Misc Distr Exp	588	OH				49,068	13,418					
25	588.03-Misc Distr Exp-Transp	588	Trans/Mat										
26	588.11 Labor - Genl Type Mtg - O	588	Labor				5,169	2,057	703				
27	588.12 OH - Genl Type Mtg	588	OH				7,920	1,431					
28	588.13-Misc Dist Exp-Genl Mtg Ti	588	Trans/Mat										
29	588.20-Misc Dist Exp-Outside Tra	588	Other	15,000									
30	588.21-Misc Dist Exp-Outside Tra	588	Labor				-	7,985	2,729				
31	588.22-Misc Dist Exp-Outside Tra	588	OH				-	5,556					
32	588.23-Misc Dist Exp-Outside Tra	588	Trans/Mat										
33	588.31 Labor - On Call - Standby	588	Labor					9,876	3,375				
34	588.32-Misc Dist Exp-On Call Sta	588	OH					6,873					
35	588.40 Safety Mtgs & Training	588	Other										
36	588.41 Labor - Safety Mtgs & Trai	588	Labor				10,049	20,274	6,928				
37	588.42 OH - Safety Mtgs & Tra	588	OH	9,650			15,397	14,109					
38	588.90 Misc Dist-Staking Dept-To	588	Other							170,671	173,944	280,422	272,260
39	589.00-Distr rents	589	Other	35,300						30,717	32,950	35,300	35,300
40													
41	**Total operations**			67,702	-	-	119,627	136,233	27,450	236,392	253,121	360,478	351,012

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Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026
Expenses By Account and By Type
Year 2013, HY 2024, FTY 2025 and FPFTY 2026

Line	Account	#	Type	E&O 2026	Office 2026	Admin & Misc 2026	C&T Payroll 2026	Union Payroll 2026	Transportation 2026	Annual Totals, By Account 2023	2024	2025	2026
42													
43	590.01-Maint, Supv & Eng-Labor	590	Labor				38,585						
44	590.02-Maint, Supv & Eng-OH	590	OH				59,121						
45	590.03-Maint, Supv & Eng-Transp	590	Trans/Mat							85,710	97,875	100,771	97,706
46	591.01-Maint of Structures-Labor	591	Labor										
47	591.02-Maint of Structures-OH	591	Trans/Mat							1,848	-	-	-
48	592.01-Maint of Station Equip-Lat	592	Labor					1,297	443				
49	592.02-Maint of Station Equip-OH	592	OH	125,850				902					
50	592.03-Maint of Station Equip-Tra	592	Trans/Mat										
51	592.04- Matl/Supp Inv-Maint Sta	592	Other	(110,119)									
52	592.11- Substation Inspect In-hou	592	Labor										
53	592.00-Substation Insp-In House-	592	Other							5,697	3,210	4,571	18,373
54	593.00 Maint OH Lines	593	Other										
55	593.01 Labor - OH Line Maintena	593	Labor					140,430	47,986				
56	593.02 OH - OH Line Mainten	593	OH	9,500				97,724					
57	593.03-Maint of OH Lines-Transp	593	Trans/Mat										
58	593.04 Matl/Supp Inv-Maint Ove	593	Trans/Mat										
59	593.10 Maint OH Lines - Brush C	593	Other	480,457									
60	593.11 OH Line-Tree Trim-In-H	593	Labor					11,621	3,971				
61	593.12-Tree Trim-In House-Trans	593	Trans/Mat					8,087					
62	593.13-Tree Trimming-In House-C	593	Labor										
63	593.21-Overhead Line Inspection	593	Trans/Mat				-	18,939	6,472				
64	593.22-OH Line Insp-Line Crew-C	593	OH				-	11,920					
65	593.30 Maint Of OH-Working Off	593	Other										
66	593.31 Labor - Maint Lines - Wor	593	Labor										
67	593.32 OH - Maint Lines - Work C	593	OH										
68	593.40 Maint Of OH Lines - Meals	593	Other	1,500									
69	593.50-Maint O/H Line-Major Stor	593	Other										
70	593.51 Labor - Maint Lines - Majo	593	Labor	18,088			-	23,165	7,916				
71	593.52 OH Lines- Major	593	Other				-	16,120					
72	593.60 Maint Lines-Major Storm-E	593	Labor										
73	593.80 Maint O/H - Testing-Tools	593	Other	40,500									
74	593.90 Maint-Special Equip-Repa	593	Other										
75	593.91-Special Equip Insp-Labor	593	Labor					6,502	2,222				
76	593.92-Special Equipment Inspec	593	Trans/Mat					4,524		836,769	869,788	969,072	957,644

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Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026
Expenses By Account and By Type
Year 2013, HY 2024, FTY 2025 and FPFTY 2026

Line	Account	#	Type	E&O 2026	Office 2026	Admin & Misc 2026	C&T Payroll 2026	Union Payroll 2026	Transportation 2026	Annual Totals, By Account 2023	2024	2025	2026
77	594.01-Maint of UG Lines-Labor	594	Labor				-	3,022	1,033				
78	594.02-Maint of UG Lines-OH	594	OH				-	2,102					
79	594.03-Maint of UG Lines-Transp	594	Trans/Mat										
80	594.04-Maint of UG Lines-Matl	594	Trans/Mat										
81	594.05-Maint UG Lines- Misc	594	Other										
82	594.11- UG Inspect In-hours	594	Labor					105	36				
83	594.12- UG Inspect OH	594	OH					73					
84	594.90- Maint UG Lines PA ON	594	Other	33,500						28,436	30,206	40,056	39,870
85	595.01-Maint of Line Xfrnrs-Labor	595	Labor					2,323	794				
86	595.02-Maint of Line Xfrnrs-OH	595	OH					1,617					
87	595.03-Maint of Line Xfrnrs-Trans	595	Trans/Mat										
88	595.05-Maint Line Xfrnrs-Misc	595	Other										
89	595.80-Maint of Line Xfrnrs-Disp	595	Trans/Mat	3,000						5,677	14,532	7,873	7,734
90	596.01-Maint of Street Lights-Lab	596	Labor					432	148				
91	596.02-Maint of Street Lights-OH	596	OH					301					
92	596.04-Maint of Street Lights-Mat	596	Trans/Mat							2,991	1,612	907	881
93	597.00-Maint of Meters	597	Labor										
94	597.01-Maint of Meters-Labor	597	Labor					23,883	8,161				
95	597.02-Maint of Meters-OH	597	OH					16,620					
96	597.03-Maint of Meters-Transp	597	Trans/Mat										
97	597.04-Maint of Meters-Matl	597	Trans/Mat										
98	597.05-Maint of Meters-Misc	597	Trans/Mat										
99	597.41-Maintenance of Meters-TV	597	Labor					432	148				
100	597.42-Maintenance of Meters-TV	597	OH	27,200				301					
101	597.44-Maint TWACS Meters	597	Other							75,467	64,505	78,208	76,746
102													
103	**Total Maint**			629,476	-	-	97,706	392,443	79,329	1,042,595	1,081,729	1,201,459	1,198,954
104													
105	**Total Distr Exp**			697,179	-	-	217,333	528,676	106,779	1,278,988	1,334,849	1,561,937	1,549,966
106													

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Rate Case with Fully Projected Future Test Year 2026
Expenses By Account and By Type
Year 2013, HY 2024, FTY 2025 and FPFTY 2026

Line	Account	#	Type	E&O 2026	Office 2026	Admin & Misc 2026	C&T Payroll 2026	Union Payroll 2026	Transportation 2026	Annual Totals, By Account 2023	2024	2025	2026
107	**CustS ACCOUNTING & COLLECTING Exp**												
108	902.01-Meter Reading Exp-Labor	902	Labor					7,591	2,594				
109	902.02-Meter Reading Exp-OH	902	OH					5,283					
110	902.03-Meter Reading Exp-Trans	902	Trans/Mat							19,808	21,775	15,922	15,467
111	903.00-Cust Rec & Coll Exp	903	Other			5,000							
112	903.01-Cust Rec & Collect Exp-La	903	Labor				206,535	1,395	477				
113	903.02-Cust Rec & Collect Exp-O	903	OH				316,458	972					
114	903.03-Cust Rec & Collect Exp-Tı	903	Trans/Mat										
115	903.20-Cust Rec Exp-Seminars-N	903	Other		500								
116	903.30-Cust Rec Exp-Postage	903	Other		43,375								
117	903.40-Cust Coll-Credit Check	903	Other		900								
118	903.45-Cust Coll-EGS Monthly Sv	903	Other		3,600								
119	903.50-Cust Rec Exp-Billing Supp	903	Other		3,200								
120	903.60-Cust Rec Exp-NISC Comp	903	Other	8,500	155,100								
121	903.81-Cust Rec Exp-Collect-Lab	903	Labor				70,942	1,817	621				
122	903.82-Cust Rec Exp-Collecting-(	903	OH				108,698	1,265					
123	903.83-Cust Rec Exp-Collect-Tra	903	Trans/Mat										
124	903.90-Cust Rec Exp-Delinq	903	Other		500								
125	903.91-Cust Rec Exp-Delinq-Labo	903	Labor				26,478	8,269	2,826				
126	903.92-Cust Rec Exp-Delinq-OH	903	OH				40,571	5,755					
127	903.05-Cust Rec Exp-Delinq-Misc	903	Other							872,949	907,634	1,015,031	1,048,782
128	904.00-Uncollectable Accounts	904	Other		20,000					-	-	20,000	20,000
129													
130	**Total Cust accounting & collecting**			8,500	227,175	5,000	769,682	32,347	6,517	892,757	929,410	1,050,953	1,084,250
131													
132	**SALES PROMOTION Exp**												
133	908.00-Cust Assist-Exp	908	Other		1,000								
134	908.51-Cust Assist-Energy Audit-I	908	Labor					109	37				
135	908.52-Cust Assist-Energy Audit-I	908	OH					76					
136	908.05-Cust Assist-Energy Audit-I	908	Other							2,030	180	1,227	1,222
137	909.00-Cust Service Info-Misc	909	Other		6,000					314	800	16,000	6,000
138	913.00-Advertising Exp	913	Other		2,500					1,738	2,191	2,500	309
139													
140	**Total Sales Promotion Exp**			-	9,500	-	-	185	37	4,082	3,171	19,727	7,531
141													

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Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026
Expenses By Account and By Type
Year 2013, HY 2024, FTY 2025 and FPFTY 2026

Line	Account	#	Type	E&O 2026	Office 2026	Admin & Misc 2026	C&T Payroll 2026	Union Payroll 2026	Transportation 2026	Annual Totals, By Account 2023	2024	2025	2026
142	**ADMINISTRATIVE & Genl Exp**												
143	920.00-A&G Salaries	920	Labor			8,140							
144	920.01-A&G Salaries-Labor	920	Labor				316,358		2,713				
145	920.02-A&G Salaries-OH	920	OH				402,852						
146	920.03-A&G Salaries-Transp	920	Trans/Mat										
147	920.40-A&G-President-CEO	920	Labor	10,853									
148	920.50-A&G-V-P Fin Adminis	920	Labor			13,566							
149	920.60-A&G-V-P Eng Oper	920	Labor	13,566									
150	920.70-A&G- Staff	920	Labor		20,530					652,639	757,901	869,897	788,577
151	921.00-Off Supp & Exp	921	Other		5,540	6,000							
152	921.10-Off Supp & Exp-Utilities	921	Other			6,060							
153	921.40-Off Exp-Subs/Membership	921	Other		3,400								
154	921.50-Off Exp-Off Supp	921	Other		23,260								
155	921.60-Off Exp-WECO Telephone	921	Other	-		49,500							
156	921.70-Off Exp-Dispatch Telepho	921	Other	86,000		4,800							
157	921.90-Off Exp-Misc	921	Other		17,700	2,360							
158	921.99-Off Exp-Working Capital C	921	Other			(94,910)				61,925	112,900	123,007	109,710
159	923.00-Outside Svc Empl	923	Other		3,925	25,400							
160	923.10-Outside Svc Empl-Auditor	923	Other			34,000							
161	923.20-Outside Svc Empl-Engine	923	Other	5,000									
162	923.30-Outside Svc Empl-Attorne	923	Other			25,000							
163	923.90-Outside Services Employe	923	Other			61,200				87,889	137,115	154,525	154,525
164	924.00-Property Insurance	924	Other			61,410				51,268	53,098	61,410	61,410
165	925.00-Injuries & Damages	925	Other							-	-	-	-
166	926.11-Employee Pen Ben-Health	926	OH										
167	926.20-Empl Pen Ben-Postret He	926	OH										
168	926.70-Employee Pen Ben-Life In	926	OH										
169	926.99-Employee Pen Ben-SERP	926	OH							-	-	-	-
170	928.00-Regulatory Commission E	928	Other			43,000							
171	928.01-Rate Case Exp	928	Other			110,393				68,366	42,985	43,000	153,393
172	930.00-Directors Exp	930	Other			106,681							
173	930.11-Misc Gen Exp-GPS Map L	930	Other										
174	930.20-Misc Gen Exp-GPS Map-L	930	Labor	2,804									
175	930.21-Misc Gen Exp-GPS Map-C	930	Other										
176	930.22-Misc Gen Exp-GPS Mapp	930	OH										
177	930.24-Misc Gen Exp-GPS Mapp	930	Other										
178	930.25-Misc Gen Exp-Covid Expe	930	Other										
179	930.30-Misc Gen Exp- Misc	930	Other	800						105,355	84,404	99,751	110,252

WP_C1

Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026
Expenses By Account and By Type
Year 2013, HY 2024, FTY 2025 and FPFTY 2026

Line	Account	#	Type	E&O 2026	Office 2026	Admin & Misc 2026	C&T Payroll 2026	Union Payroll 2026	Transportation 2026	Annual Totals, By Account 2023	2024	2025	2026
180	931.00-Rents	931	Other		2,200					2,442	3,611	2,200	2,200
181	932.00-Maint of Genl Property	932	Other	5,790		38,000							
182	932.01-Maint of Genl Property-La	932	Labor					7,506	2,565				
183	932.02-Maint of Genl Property-OH	932	OH					2,625					
184	932.10-Maint of Genl Property-Ofl	932	Other	5,538									
185	932.11-Maint Genl Prop-Off Bldg-	932	Labor										
186	932.12-Maint Genl Prop-Off Bldg-	932	OH										
187	932.20-Maint Genl-Communicatio	932	Other	252									
188	932.21-Maint Genl-Comm Equip-l	932	Labor										
189	932.22-Maint Genl-Comm Equip-(	932	OH										
190	932.30-Maint Gen Property-Plant	932	Other	6,319			-						
191	932.31-Maint Gen Prop-Plant Bld	932	Labor					1,086	371				
192	932.32-Maint Gen Prop-Plant Bld	932	OH					381					
193	932.41-Maint Gen Prop-Apt Hous	932	Labor										
194	932.42-Maint Gen Prop-Apt Hous	932	OH										
195	932.70-Maint Gen Office Equip	932	Other		1,913								
196	932.05-Maint Genl Property- Misc	932	Other							112,580	72,186	132,847	72,345
197				136,921	78,468	500,599	719,210	11,597	5,649				
198	**Total Administrative & Genl Exp**			136,921	78,468	500,599	719,210	11,597	5,649	1,142,464	1,264,200	1,486,637	1,452,412
199	Detail, adjusted for WC Claim												
200	**Total Operating Exp**			842,600	315,143	505,599	1,706,224	572,805	118,982	3,318,291	3,531,630	4,119,254	4,094,159
201	From OM									0	0	0	32,806
202	Adjustments												
203	Working Capital claim												
204	Rate case Exp												
205				842,600	315,143	505,599	1,706,224	572,805	118,982				
206	From OM												
207	From C1-1												
208	Differrence												
209													
210													
211	Labor		Labor	45,763	20,530	21,706	706,139	321,317	112,511				
212	OH		OH	172,200	-	-	1,000,085	203,817	-				
213	Trans/Mat		Trans/Ma	3,000	-	-	-	31,550	6,472				
214	Other		Other	621,637	294,613	483,894	-	16,120	-				
215	WC		WC	-	-	-	-	-	-				
216				842,600	315,143	505,599	1,706,224	572,805	118,982				

WP_C1

				Company Proposed					
				E&O	Office	Admin & Misc	C&T Payroll	Union Payroll	Transportation
Line	Account	#	Type	2026	2026	2026	2026	2026	2026
1	PPower-Power Purchases								
2	Total Power Purchased								
3									
4	580.01-Oper.Superv. Eng-Labor	580	Labor						
5	580.02-Oper.Superv. Eng-OH	580	OH						
6	580.03-Oper.Superv. Eng-Transp	580	Trans/Mat						
7	582.01-Station Exp-Labor	582	Labor						
8	582.02-Station Exp-OH	582	Trans/Mat						
9	583.01-OH Line Exp-Labor	583	Labor					3,054	1,044
10	583.02-OH Line Exp-OH	583	OH						
11	583.05-OH Line Exp-Misc	583	Trans/Mat						
12	585.01-Street/Signal Light-Labor	585	Labor					136	46
13	585.02-Street/Signal Light-OH	585	OH						
14	585.04-Street/Signal Light-Matl	585	Trans/Mat						
15	586.01-Meter Exp-Labor	586	Labor	500			-	19,737	6,744
16	586.02-Meter Exp-OH	586	OH						
17	586.03-Meter Exp-Transp	586	Trans/Mat						
18	586.05-Meter Exp-Misc	586	Other						
19	587.01-Cust Install Exp-Labor	587	Labor				-	136	46
20	587.02-Cust Install Exp-OH	587	OH						
21	587.04-Cust Install Exp-Matl	587	Trans/Mat						
22	588.00 Misc Distr Exps	588	Other						
23	588.01 Labor - Misc Distr Expens	588	Labor				35,409	21,320	7,285
24	588.02 OH - Misc Distr Exp	588	OH						
25	588.03-Misc Distr Exp-Transp	588	Trans/Mat						
26	588.11 Labor - Genl Type Mtg - O	588	Labor				5,715	2,274	777
27	588.12 OH - Genl Type Mtg	588	OH						
28	588.13-Misc Dist Exp-Genl Mtg Ty	588	Trans/Mat						
29	588.20-Misc Dist Exp-Outside Tra	588	Other						
30	588.21-Misc Dist Exp-Outside Tra	588	Labor				-	8,829	3,017
31	588.22-Misc Dist Exp-Outside Tra	588	OH						
32	588.23-Misc Dist Exp-Outside Tra	588	Trans/Mat						
33	588.31 Labor - On Call - Standby	588	Labor					10,920	3,731
34	588.32-Misc Dist Exp-On Call Sta	588	OH						
35	588.40 Safety Mtgs & Training	588	Other						
36	588.41 Labor - Safety Mtgs & Trai	588	Labor				11,111	22,417	7,660
37	588.42 OH - Safety Mtgs & Tra	588	OH						
38	588.90 Misc Dist-Staking Dept-To	588	Other						
39	589.00-Distr rents	589	Other						
40									
41	**Total operations**			500	-	-	52,236	88,823	30,352

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				Company Proposed					
				E&O	Office	Admin & Misc	C&T Payroll	Union Payroll	Transportation
Line	Account	#	Type	2026	2026	2026	2026	2026	2026
42									
43	590.01-Maint, Supv & Eng-Labor	590	Labor				42,663		
44	590.02-Maint, Supv & Eng-OH	590	OH						
45	590.03-Maint, Supv & Eng-Transp	590	Trans/Mat						
46	591.01-Maint of Structures-Labor	591	Labor						
47	591.02-Maint of Structures-OH	591	Trans/Mat						
48	592.01-Maint of Station Equip-Lat	592	Labor					1,434	490
49	592.02-Maint of Station Equip-OH	592	OH						
50	592.03-Maint of Station Equip-Tra	592	Trans/Mat						
51	592.04- Matl/Supp Inv-Maint Sta	592	Other						
52	592.11- Substation Inspect In-hou	592	Labor						
53	592.00-Substation Insp-In House-	592	Other						
54	593.00 Maint OH Lines	593	Other						
55	593.01 Labor - OH Line Maintena	593	Labor					155,274	53,059
56	593.02 OH - OH Line Mainten	593	OH						
57	593.03-Maint of OH Lines-Transp	593	Trans/Mat						
58	593.04 Matl/Supp Inv-Maint Ove	593	Trans/Mat						
59	593.10 Maint OH Lines - Brush C	593	Other						
60	593.11 OH Line-Tree Trim-In-H	593	Labor					12,849	4,391
61	593.12-Tree Trim-In House-Trans	593	Trans/Mat						
62	593.13-Tree Trimming-In House-C	593	Labor						
63	593.21-Overhead Line Inspection	593	Trans/Mat						
64	593.22-OH Line Insp-Line Crew-C	593	OH						
65	593.30 Maint Of OH-Working Off	593	Other						
66	593.31 Labor - Maint Lines - Wor	593	Labor						
67	593.32 OH - Maint Lines - Work C	593	OH						
68	593.40 Maint Of OH Lines - Meals	593	Other						
69	593.50-Maint O/H Line-Major Stor	593	Other						
70	593.51 Labor - Maint Lines - Majo	593	Labor	20,000			-	25,614	8,753
71	593.52 OH Lines- Major	593	Other						
72	593.60 Maint Lines-Major Storm-E	593	Labor						
73	593.80 Maint O/H - Testing-Tools	593	Other						
74	593.90 Maint-Special Equip-Repa	593	Other						
75	593.91-Special Equip Insp-Labor	593	Labor					7,189	2,457
76	593.92-Special Equipment Inspec	593	Trans/Mat						

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				Company Proposed					
				E&O	Office	Admin & Misc	C&T Payroll	Union Payroll	Transportation
Line	Account	#	Type	2026	2026	2026	2026	2026	2026
77	594.01-Maint of UG Lines-Labor	594	Labor				-	3,341	1,142
78	594.02-Maint of UG Lines-OH	594	OH						
79	594.03-Maint of UG Lines-Transp	594	Trans/Mat						
80	594.04-Maint of UG Lines-Matl	594	Trans/Mat						
81	594.05-Maint UG Lines- Misc	594	Other						
82	594.11- UG Inspect In-hours	594	Labor					116	40
83	594.12- UG Inspect OH	594	OH						
84	594.90- Maint UG Lines PA ON	594	Other						
85	595.01-Maint of Line Xfrnrs-Labor	595	Labor					2,569	878
86	595.02-Maint of Line Xfrnrs-OH	595	OH						
87	595.03-Maint of Line Xfrnrs-Trans	595	Trans/Mat						
88	595.05-Maint Line Xfrnrs-Misc	595	Other						
89	595.80-Maint of Line Xfrnrs-Disp	595	Trans/Mat						
90	596.01-Maint of Street Lights-Lab	596	Labor					478	163
91	596.02-Maint of Street Lights-OH	596	OH						
92	596.04-Maint of Street Lights-Mat	596	Trans/Mat						
93	597.00-Maint of Meters	597	Labor						
94	597.01-Maint of Meters-Labor	597	Labor					26,408	9,024
95	597.02-Maint of Meters-OH	597	OH						
96	597.03-Maint of Meters-Transp	597	Trans/Mat						
97	597.04-Maint of Meters-Matl	597	Trans/Mat						
98	597.05-Maint of Meters-Misc	597	Trans/Mat						
99	597.41-Maintenance of Meters-TV	597	Labor					478	163
100	597.42-Maintenance of Meters-TV	597	OH						
101	597.44-Maint TWACS Meters	597	Other						
102									
103	**Total Maint**			20,000	-	-	42,663	235,750	80,558
104									
105	**Total Distr Exp**			20,500	-	-	94,899	324,573	110,910
106									

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				Company Proposed					
				E&O	Office	Admin & Misc	C&T Payroll	Union Payroll	Transportation
Line	Account	#	Type	2026	2026	2026	2026	2026	2026
107	**CustS ACCOUNTING & COLLECTING Exp**								
108	902.01-Meter Reading Exp-Labor	902	Labor					8,393	2,868
109	902.02-Meter Reading Exp-OH	902	OH						
110	902.03-Meter Reading Exp-Trans	902	Trans/Mat						
111	903.00-Cust Rec & Coll Exp	903	Other						
112	903.01-Cust Rec & Collect Exp-La	903	Labor				228,366	1,543	527
113	903.02-Cust Rec & Collect Exp-O	903	OH						
114	903.03-Cust Rec & Collect Exp-Tı	903	Trans/Mat						
115	903.20-Cust Rec Exp-Seminars-M	903	Other						
116	903.30-Cust Rec Exp-Postage	903	Other						
117	903.40-Cust Coll-Credit Check	903	Other						
118	903.45-Cust Coll-EGS Monthly Sv	903	Other						
119	903.50-Cust Rec Exp-Billing Supp	903	Other						
120	903.60-Cust Rec Exp-NISC Comp	903	Other						
121	903.81-Cust Rec Exp-Collect-Lab	903	Labor				78,440	2,009	686
122	903.82-Cust Rec Exp-Collecting-(	903	OH						
123	903.83-Cust Rec Exp-Collect-Tra	903	Trans/Mat						
124	903.90-Cust Rec Exp-Delinq	903	Other						
125	903.91-Cust Rec Exp-Delinq-Labo	903	Labor				29,277	9,143	3,124
126	903.92-Cust Rec Exp-Delinq-OH	903	OH						
127	903.05-Cust Rec Exp-Delinq-Misc	903	Other						
128	904.00-Uncollectable Accounts	904	Other						
129									
130	**Total Cust accounting & collecting**			-	-	-	336,083	21,088	7,206
131									
132	**SALES PROMOTION Exp**								
133	908.00-Cust Assist-Exp	908	Other						
134	908.51-Cust Assist-Energy Audit-I	908	Labor					120	41
135	908.52-Cust Assist-Energy Audit-I	908	OH						
136	908.05-Cust Assist-Energy Audit-I	908	Other						
137	909.00-Cust Service Info-Misc	909	Other						
138	913.00-Advertising Exp	913	Other						
139									
140	**Total Sales Promotion Exp**			-	-	-	-	120	41
141									

WP_C1

				Company Proposed					
				E&O	Office	Admin & Misc	C&T Payroll	Union Payroll	Transportation
Line	Account	#	Type	2026	2026	2026	2026	2026	2026
142	**ADMINISTRATIVE & Genl Exp**								
143	920.00-A&G Salaries	920	Labor			9,000			
144	920.01-A&G Salaries-Labor	920	Labor				349,797		3,000
145	920.02-A&G Salaries-OH	920	OH						
146	920.03-A&G Salaries-Transp	920	Trans/Mat						
147	920.40-A&G-President-CEO	920	Labor	12,000					
148	920.50-A&G-V-P Fin Adminis	920	Labor			15,000			
149	920.60-A&G-V-P Eng Oper	920	Labor	15,000					
150	920.70-A&G- Staff	920	Labor		22,700				
151	921.00-Off Supp & Exp	921	Other						
152	921.10-Off Supp & Exp-Utilities	921	Other						
153	921.40-Off Exp-Subs/Membership	921	Other						
154	921.50-Off Exp-Off Supp	921	Other						
155	921.60-Off Exp-WECO Telephone	921	Other						
156	921.70-Off Exp-Dispatch Telepho	921	Other						
157	921.90-Off Exp-Misc	921	Other						
158	921.99-Off Exp-Working Capital C	921	Other						
159	923.00-Outside Svc Empl	923	Other						
160	923.10-Outside Svc Empl-Auditor	923	Other						
161	923.20-Outside Svc Empl-Engine	923	Other						
162	923.30-Outside Svc Empl-Attorne	923	Other						
163	923.90-Outside Services Employe	923	Other						
164	924.00-Property Insurance	924	Other						
165	925.00-Injuries & Damages	925	Other						
166	926.11-Employee Pen Ben-Health	926	OH						
167	926.20-Empl Pen Ben-Postret He	926	OH						
168	926.70-Employee Pen Ben-Life In	926	OH						
169	926.99-Employee Pen Ben-SERP	926	OH						
170	928.00-Regulatory Commission E	928	Other						
171	928.01-Rate Case Exp	928	Other						
172	930.00-Directors Exp	930	Other						
173	930.11-Misc Gen Exp-GPS Map L	930	Other						
174	930.20-Misc Gen Exp-GPS Map-L	930	Labor	3,100					
175	930.21-Misc Gen Exp-GPS Map-C	930	Other						
176	930.22-Misc Gen Exp-GPS Mappi	930	OH						
177	930.24-Misc Gen Exp-GPS Mappi	930	Other						
178	930.25-Misc Gen Exp-Covid Expe	930	Other						
179	930.30-Misc Gen Exp- Misc	930	Other						

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Line	Account	#	Type	Company Proposed E&O 2026	Office 2026	Admin & Misc 2026	C&T Payroll 2026	Union Payroll 2026	Transportation 2026
180	931.00-Rents	931	Other						
181	932.00-Maint of Genl Property	932	Other						
182	932.01-Maint of Genl Property-La	932	Labor					8,299	2,836
183	932.02-Maint of Genl Property-OH	932	OH						
184	932.10-Maint of Genl Property-Ofl	932	Other						
185	932.11-Maint Genl Prop-Off Bldg-	932	Labor						
186	932.12-Maint Genl Prop-Off Bldg-	932	OH						
187	932.20-Maint Genl-Communicatio	932	Other						
188	932.21-Maint Genl-Comm Equip-L	932	Labor						
189	932.22-Maint Genl-Comm Equip-(	932	OH						
190	932.30-Maint Gen Property-Plant	932	Other						
191	932.31-Maint Gen Prop-Plant Bld	932	Labor					1,201	410
192	932.32-Maint Gen Prop-Plant Bld	932	OH						
193	932.41-Maint Gen Prop-Apt Hous	932	Labor						
194	932.42-Maint Gen Prop-Apt Hous	932	OH						
195	932.70-Maint Gen Office Equip	932	Other						
196	932.05-Maint Genl Property- Misc	932	Other						
197				30,100	22,700	24,000	349,797	9,500	6,246
198	**Total Administrative & Genl Exp**			30,100	22,700	24,000	349,797	9,500	6,246
199	Detail, adjusted for WC Claim								
200	**Total Operating Exp**			50,600	22,700	24,000	780,779	355,281	124,403
201	From OM								
202	Adjustments								
203	Working Capital claim								
204	Rate case Exp								
205									
206	From OM								
207	From C1-1								
208	Differrence								
209									
210									
211	Labor		Labor						
212	OH		OH						
213	Trans/Mat		Trans/Ma						
214	Other		Other						
215	WC		WC						
216									

1,357,763	Company Proposed FPFTY Labor
1,135,323	Company 2024 Labor
1,227,966	OCA Proposed FPFTY Labor
(129,798)	OCA Adjustment to Labor
120,805	Company Proposed Non-Labor Account 932
60,822	OCA Proposed Non-Labor Account 932
(59,983)	OCA Adjustment to Account 932 Non-Labor Expense

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No. R-2025-3054392
	:	
Wellsboro Electric Company	:	

VERIFICATION

I, Greg R. Meyer, hereby state that the facts above set forth in my Direct Testimony, OCA Statement No. 1, are true and correct to the best of my knowledge, information, and belief and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa.C.S. § 4904 (relating to unsworn falsification to authorities).

DATED: July 15, 2025

Signature: */s/Greg R. Meyer*
Greg R. Meyer

Address: Brubaker & Associates Inc.
16690 Swingley Ridge Road, Suite 140
Chesterfield, MO 63017

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
v.	)	**R-2025-3054394**
	)	**R-2025-3054393**
Citizens' Electric Company of Lewisburg, PA, Valley Energy, Inc., and Wellsboro Electric Company	)	**R-2025-3054392**

Corrected Direct Testimony & Exhibits of

Christopher C. Walters

OCA Statement 2

On behalf of

Pennsylvania Office of Consumer Advocate

Date Served: July 15, 2025
Corrected Version Served: July 31, 2025

BRUBAKER & ASSOCIATES, INC.

Project 11858

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
v.	)	**R-2025-3054394**
	)	**R-2025-3054393**
Citizens' Electric Company of Lewisburg, PA, Valley Energy, Inc., and Wellsboro Electric Company	)	**R-2025-3054392**

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QUALIFICATIONS OF CHRISTOPHER C. WALTERS .....Appendix A

EXHIBIT CCW-1 THROUGH EXHIBIT CCW-15

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
v.	)	**R-2025-3054394**
	)	**R-2025-3054393**
Citizens' Electric Company of Lewisburg, PA, Valley Energy, Inc., and Wellsboro Electric Company	)	**R-2025-3054392**

Direct Testimony of Christopher C. Walters

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Christopher C. Walters. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q WHAT IS YOUR OCCUPATION?

A I am a consultant in the field of public utility regulation and a Principal with the firm of Brubaker & Associates, Inc. ("BAI"), energy, economic and regulatory consultants.

Q PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A This information is included in Appendix A to my testimony.

Q ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?

A I am appearing on behalf of the Pennsylvania Office of Consumer Advocate ("OCA").

Q PLEASE GIVE A BRIEF OVERVIEW OF YOUR TESTIMONY.

A The purpose of my testimony is to provide a recommendation to the Pennsylvania Public Utility Commission ("Commission") on behalf of OCA regarding an appropriate return on equity ("ROE") the Commission should authorize for Valley Energy, Inc. ("Valley"), Citizens' Electric Company of Lewisburg, PA ("Citizens"), and Wellsboro Electric Company ("Wellsboro"), (collectively the "Companies"), in this general rate case.

My silence with regard to any position taken by the Companies in the application or direct testimony in this proceeding does not indicate my endorsement of that position.

I. SUMMARY

Q PLEASE SUMMARIZE THE REST OF YOUR TESTIMONY.

A In Section II of my testimony, I review and analyze the regulated utility industry's access to capital, credit rating trends, and outlooks, as well as the overall trend in the authorized ROE for utilities throughout the country. I conclude that the trend in authorized ROEs for utilities has declined over the last several years and has remained below 10.0% in more recent history. I also review the impact that the Federal Reserve's ("the Fed") monetary policy actions have had on the cost of capital.

In Section III of my testimony, I address the Companies' proposed capital structure and cost of long-term debt and explain why I am not taking issue with the Companies' claim on either. I then outline how a fair ROE should be established, provide an overview of the market's perception of the Companies' investment risk, and present the analyses I relied on to estimate an appropriate ROE for the Companies. Based on the results of several cost of equity estimation methods performed on publicly

traded utility companies, I estimate the current fair market ROE to fall within the range of 9.00% to 10.00%. Based on my assessment of the Companies' overall risk profile and the results of the analytical methods, I recommend the Companies be awarded an ROE of 9.50%, which is the mid-point of my overall estimated range. As shown in the Direct Testimony of Greg Meyer, OCA Statement 1 for Citizens, Wellsboro, and Valley, my recommended ROE of 9.50% would result in downward adjustments to the proposed revenue requirement for each Company.

In Section IV of my testimony, I respond to the recommendations offered by the Companies' cost of capital witness Mr. Dylan D'Ascendis as it relates to the overall rate of return ("ROR"). Mr. D'Ascendis recommends the Companies be authorized an ROE of 11.65%, which is the average of his analytical results adjusted for flotation costs. I demonstrate that his ROE recommendation is excessive and should be rejected.

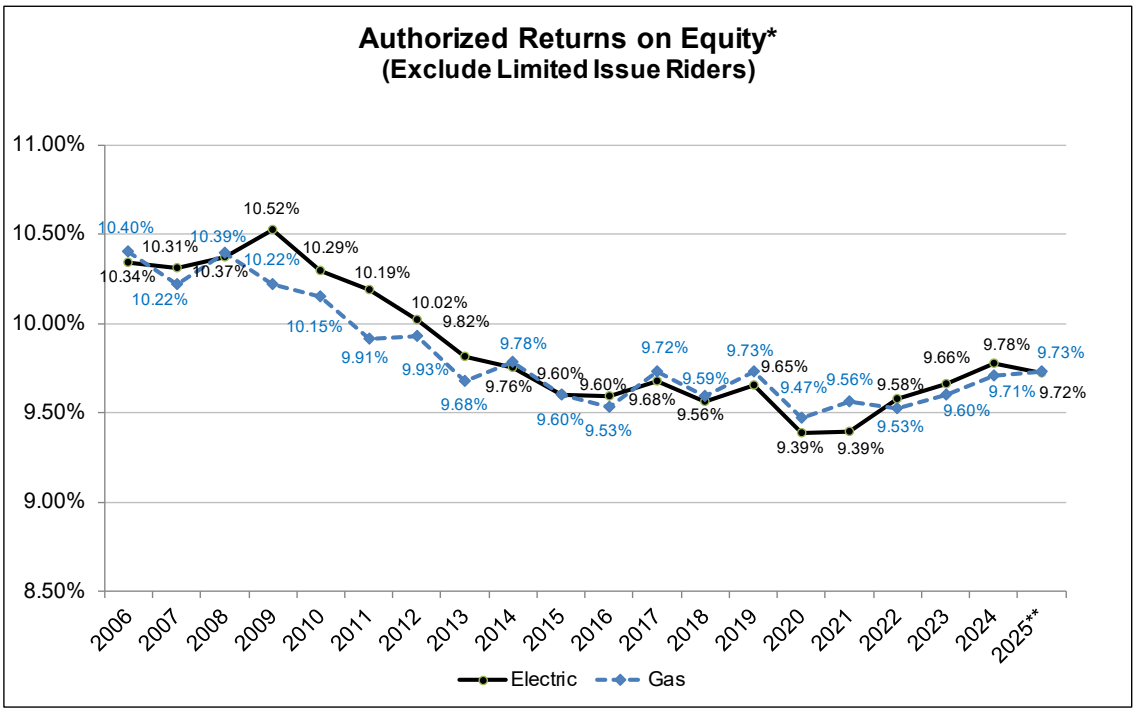
II. INDUSTRY TRENDS AND ECONOMIC ENVIRONMENT

A. Regulated Utility Industry Authorized ROEs Access to Capital and Credit Strength

Q PLEASE DESCRIBE THE OBSERVABLE EVIDENCE ON TRENDS IN AUTHORIZED ROES FOR ELECTRIC AND GAS UTILITIES.

A Authorized ROEs for both electric and gas utilities have declined below 10.0% for about the last 13 years, as illustrated in Figure CCW-1.

FIGURE CCW-1



Source and Notes:
* Electric Returns exclude Limited Issue Riders.
** *S&P Global Market Intelligence*, RRA Regulatory Focus, Major Rate Case Decisions -- January - March 2025, April 25, 2025 at page 3.

Q PLEASE DESCRIBE THE DISTRIBUTION OF AUTHORIZED ROES FOR ELECTRIC UTILITIES FOR THE LAST FEW YEARS.

A The distribution of authorized returns, annually, since 2016 is summarized in Table CCW-1.

TABLE CCW-1

Distribution of Authorized ROEs

	Electric[1]					Natural Gas[1]				
Year	Average	Median	Share of Decisions ≤ 9.5%	Share of Decisions ≤ 9.7%	Share of Decisions ≤ 10.0%	Average	Median	Share of Decisions ≤ 9.5%	Share of Decisions ≤ 9.7%	Share of Decisions ≤ 10.0%
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(6)
2016	9.60%	9.60%	41%	53%	94%	9.53%	9.50%	56%	72%	92%
2017[1]	9.68%	9.60%	40%	67%	81%	9.73%	9.60%	39%	70%	74%
2018[2]	9.56%	9.58%	45%	61%	100%	9.59%	9.60%	46%	67%	95%
2019	9.65%	9.65%	36%	58%	88%	9.73%	9.73%	19%	48%	87%
2020[3]	9.39%	9.48%	64%	79%	98%	9.47%	9.44%	60%	77%	100%
2021	9.39%	9.50%	57%	80%	97%	9.56%	9.60%	44%	67%	98%
2022	9.58%	9.53%	50%	59%	79%	9.53%	9.60%	48%	76%	97%
2023	9.66%	9.60%	38%	65%	90%	9.60%	9.55%	46%	73%	92%
2024	9.78%	9.78%	24%	37%	85%	9.71%	9.73%	33%	50%	95%
2025	9.68%	9.75%	38%	44%	94%	9.74%	9.80%	18%	27%	100%
Average	9.60%	9.61%	43%	60%	91%	9.62%	9.61%	41%	63%	93%
Median	9.62%	9.60%	41%	60%	92%	9.59%	9.60%	45%	69%	95%

Source and Notes:
S&P Global Market Intelligence, data through May 30, 2025.
[1]Includes authorized base ROE of 9.4% for Nevada Power Company, which excludes incentives associated with the Lenzie facility.
[2]Includes authorized base ROE of 9.6% for Interstate Power & Light Co., which excludes allowed ROE for generating facilities subject to special ratemaking principles.
[3]Includes authorized base ROE of 9.8% for Interstate Power & Light Co., which excludes allowed ROE for generating facilities subject to special ratemaking principles.
*Excludes Limited Issue Rider Cases.

The distribution shows that the majority of authorized ROEs since 2016 have been below 9.7%, with many being below 9.5%.

Q HOW HAS THE AUTHORIZED COMMON EQUITY RATIO FLUCTUATED OVER THE SAME TIME PERIOD FOR UTILITIES?

A In general, the utility industry's common equity ratio has not deviated much from the range of 50.0% to 52.0%. As shown in Table CCW-2, I have provided the authorized common equity ratios for utilities around the country, excluding the reported common

equity ratios for Arkansas, Florida, Indiana, and Michigan. For my overall market analysis, I have excluded the reported authorized common equity ratios for these states because these jurisdictions include sources of capital outside of investor-supplied capital such as accumulated deferred income taxes. As such, the reported common equity ratios in these states would result in a downward bias in the reported permanent common equity ratios authorized for ratemaking purposes within my trend analysis.

TABLE CCW-2

Trends in State Authorized Common Equity Ratios
(Industry)

		Electric[1]		Natural Gas[1]		Water[2]	
Line	Year	Average	Median	Average	Median	Average	Median
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	2013	50.12%	51.03%	51.16%	50.43%	48.34%	48.66%
2	2014	50.28%	50.00%	51.90%	51.99%	49.69%	50.27%
3	2015	49.89%	50.47%	49.79%	50.33%	51.52%	51.68%
4	2016	49.70%	49.99%	51.85%	51.35%	50.65%	50.77%
5	2017	50.02%	49.85%	51.13%	51.76%	48.43%	46.09%
6	2018	50.60%	50.23%	51.56%	51.51%	52.41%	53.22%
7	2019	51.55%	51.37%	52.81%	52.42%	50.75%	50.35%
8	2020	50.93%	51.17%	52.34%	52.00%	49.75%	49.10%
9	2021	51.01%	52.00%	51.90%	52.00%	51.96%	52.73%
10	2022	51.57%	51.92%	51.65%	52.00%	51.53%	51.15%
11	2023	51.59%	52.27%	52.45%	52.00%	52.53%	53.40%
12	2024	51.07%	52.10%	52.25%	52.40%	52.02%	52.13%
13	2025	50.35%	51.12%	51.39%	50.00%	47.69%	47.69%
11	Min	49.70%	49.85%	49.79%	50.00%	47.69%	46.09%
12	Max	51.59%	52.27%	52.81%	52.42%	52.53%	53.40%
14	Average	50.67%	51.04%	51.71%	51.55%	50.56%	50.56%
15	Median	50.60%	51.12%	51.85%	51.99%	50.75%	50.77%

Source and Notes:
[1] S&P Global Market Intelligence; data through May 30, 2025.
[2] S&P Global Market Intelligence; data through March 31, 2025.
- Excludes Arkansas, Florida, Indiana and Michigan because they include non-investor capital.

Q HAVE UTILITIES BEEN ABLE TO ACCESS EXTERNAL CAPITAL TO SUPPORT CAPITAL EXPENDITURE PROGRAMS?

A Yes. Regulatory Research Associates' ("RRA") October 22, 2024 Utility Capital Expenditures report, *RRA Financial Focus*, a division of *S&P Global Market Intelligence*, made several relevant comments about utility investments generally:[1]

- Energy utility capex estimates for 2025, 2026 and 2027 indicate successively higher spending levels, reaching $192 billion, $196.5 billion and $197 billion, respectively. Spending in these years is likely to increase further, as the companies' plans for future projects continue to solidify around federal and state legislation supporting infrastructure investment.

- Multiple drivers are expected to elevate utility capital expenditures over the next several years. Pent-up demand to replace aging equipment is already pushing utilities to make considerable investments in infrastructure. Meanwhile, the renewable energy portfolio standards for multiple states continue to ramp up, with the plans specifying large expansions of low-carbon energy generation capacity. Amplifying these factors are federal infrastructure investment plans, including the Inflation Reduction Act of 2022, which aim to convert the US power generation network to a majority of zero-carbon sources by 2035.

- Forecast aggregate utility investments in 2025, 2026 and 2027 are expected to reach new records of $192 billion, $196.5 billion and $197 billion, respectively. The increases are being driven in large part by federal legislation enacted in 2021 and 2022, supporting infrastructure investment and state-level energy transition plans and incentives, as well as robust growth in demand from datacenters, as the explosion in implementation of AI and cloud computing continues.

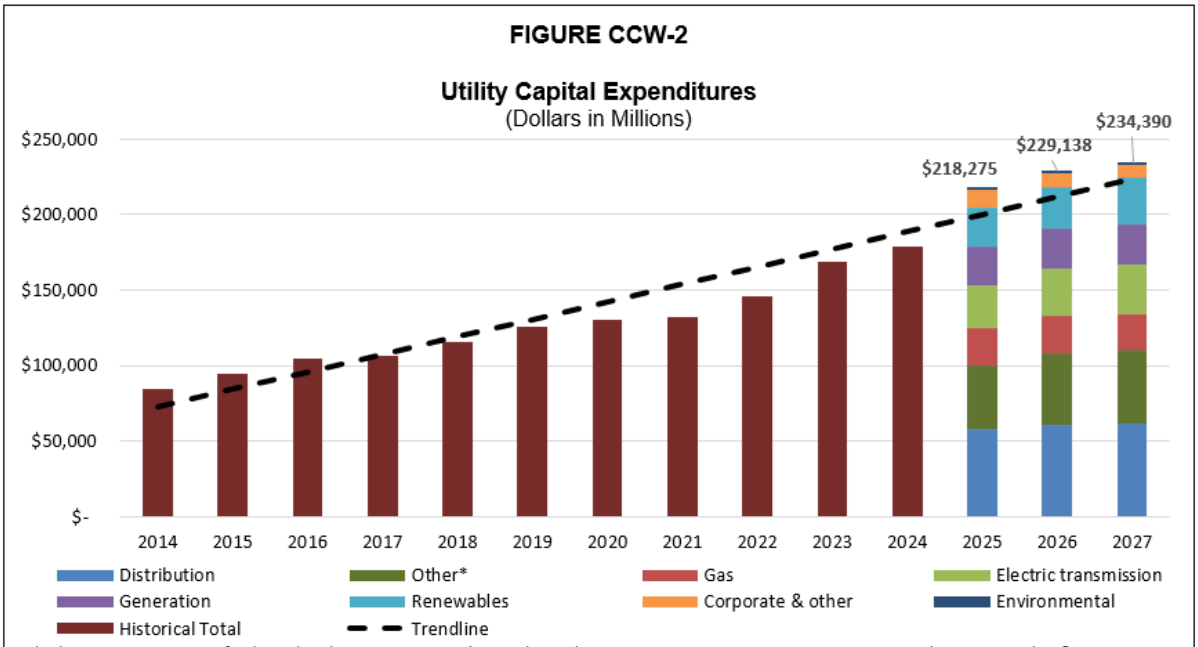
- Utilities have multiple opportunities to finance and support energy investments through mechanisms available within the Inflation Reduction Act and the Infrastructure Investment and Jobs Act of 2021. These pieces of legislation provide billions of dollars for power infrastructure investments, financial incentives for nuclear

[1] *S&P Global Market Intelligence, RRA Financial Focus*: "Utility capital expenditures update," October 22, 2024.

power plants and funding for battery storage technology, among other provisions.

As shown in Figure CCW-2 below, capital expenditures for the regulated electric and natural gas delivery utilities have increased considerably over the period 2023 into 2024, and the forecasted capital expenditures remain elevated through the end of 2026.

FIGURE CCW-2



*Other category consists of utilities that do not report capital expenditures by category: Avista, Dominion Energy, MDU, NorthWestern, and PG&E.
Source: *S&P Global Market Intelligence, RRA Financial Focus*, Utility Capital Expenditures Update, March 24, 2025, Tables 1 and 3.

As demonstrated in Figure CCW-2, and in the comments made by *RRA S&P Global Market Intelligence*, capital investments for the utility industry continue to stay at elevated levels, and these capital expenditures are expected to fuel utilities' profit growth into the foreseeable future. This is clear evidence that these capital investments are enhancing shareholder value and are attracting both equity and debt capital to the utility industry in a manner that allows for funding these elevated capital investments. While capital markets embrace these profit-driven capital investments, regulatory commissions also must be careful to maintain reasonable prices and tariff terms and

conditions to protect customers' needs for reliable utility service at reasonable rates. If this is not done, utility rates will expand beyond the ability of customers to pay, resulting in revenue constraints for utilities, which will impact their financial integrity.

Q IS THERE EVIDENCE OF ROBUST VALUATIONS OF REGULATED UTILITY EQUITY SECURITIES?

A Yes. Strong valuations demonstrate that utilities can issue securities at favorable prices and price multiples, signaling their ability to access equity capital on reasonable terms and at a relatively low cost. As shown on Exhibit CCW-1, the historical valuation of utilities followed by *The Value Line Investment Survey* ("*Value Line*"), based on a Price-to-Earnings ("P/E") ratio, Price-to-Cash Flow ratio, and Market Price-to-Book value ratio, indicates utility security valuations today are very strong and robust relative to the last several years. These strong valuations of utility stocks indicate that utilities have access to equity capital under reasonable terms and at lower costs.

Q WHAT CONCLUSION DO YOU DRAW FROM THIS OBSERVABLE MARKET DATA IN FORMING YOUR RECOMMENDED ROE AND OVERALL ROR?

A Generally, authorized ROEs, credit standing, and access to capital have been quite robust for utilities over the last several years, even throughout the duration of the global pandemic. It is critical that the Commission ensure that utility rates are increased no more than necessary to provide fair compensation and maintain financial integrity.

B. Impact of Monetary Policy

Q ARE THE FEDERAL OPEN MARKET COMMITTEE'S ("FOMC") ACTIONS KNOWN TO THE MARKET PARTICIPANTS, AND IS IT REASONABLE TO BELIEVE THEY ARE REFLECTED IN THE MARKET'S VALUATION OF BOTH DEBT AND EQUITY SECURITIES?

A Yes, to both questions. The FOMC communicates its monetary policy objectives with a high degree of transparency, including its dual mandate to achieve maximum employment and stable inflation near 2%. To achieve these objectives, the FOMC adjusts its policy stance in phases depending on economic conditions. For example, in response to the pandemic-induced downturn, the FOMC adopted an accommodative stance by lowering the federal funds rate to near zero and engaging in Quantitative Easing, purchasing Treasury securities and agency mortgage-backed securities to support market liquidity and economic growth.

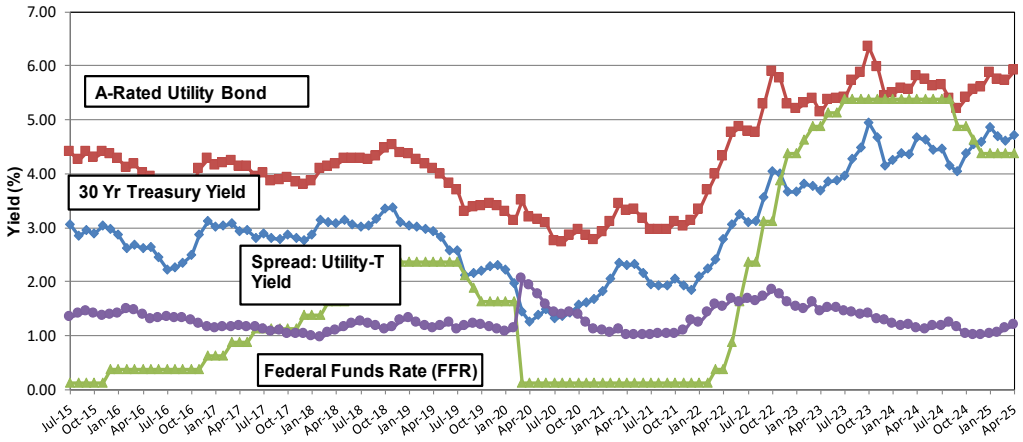
Beginning in March 2022, the FOMC transitioned to a tightening phase, raising the target federal funds rate. In June 2022, it began reducing its balance sheet (Quantitative Tightening) by allowing maturing Treasury and agency Mortgage Backed Securities to roll off its balance sheet without reinvestment. That phase of policy tightening persisted into 2024.

Since September 2024, the FOMC has lowered the federal funds rate three times, signaling a shift toward a more accommodative or neutral stance in response to evolving economic data. While balance sheet reduction continues, the pace has slowed considerably, especially for Treasury securities, reflecting a more measured policy approach.

Market reactions to these actions are reflected in the valuation of debt and equity securities. A visualization of the market's response to the federal funds rate changes is shown in Figure CCW-3 below.

FIGURE CCW-3

Timeline of Federal Funds Rate Changes Since 2015



Fed FFR Actions:

1	December 2015	0.25	→	0.50	15	March 2022	0.25	→	0.50
2	December 2016	0.50	→	0.75	16	May 2022	0.75	→	1.00
3	March 2017	0.75	→	1.00	17	June 2022	1.50	→	1.75
4	June 2017	1.00	→	1.25	18	July 2022	2.25	→	2.50
5	December 2017	1.25	→	1.50	19	September 2022	3.00	→	3.25
6	March 2018	1.50	→	1.75	20	November 2022	3.75	→	4.00
7	June 2018	1.75	→	2.00	21	December 2022	4.25	→	4.50
8	September 2018	2.00	→	2.25	22	February 2023	4.50	→	4.75
9	December 2018	2.25	→	2.50	23	March 2023	4.75	→	5.00
10	August 2019	2.00	→	2.25	24	May 2023	5.00	→	5.25
11	September 2019	1.75	→	2.00	25	July 2023	5.25	→	5.50
12	October 2019	1.50	→	1.75	26	September 2024	4.75	→	5.00
13	March 2020	1.00	→	1.25	27	November 2024	4.50	→	4.75
14	March 2020	0.00	→	0.25	28	December 2024	4.25	→	4.50

Sources:
Federal Reserve Bank of New York, https://apps.newyorkfed.org/markets/autorates/fed-funds-search-page
Board of Governors of the Federal Reserve System, https://www.federalreserve.gov/datadownload/
Mergent Bond Record.

As shown in Figure CCW-3, the federal funds rate has risen more rapidly than Utility and Treasury bond yields. Meanwhile, the yield spread between Utility bonds and Treasury bonds has narrowed and is currently below its long-term average. This narrower spread suggests that investors perceive lower relative risk in Utility bonds

compared to Treasuries, requiring less additional yield to hold them. This trend typically reflects greater confidence in the financial stability and creditworthiness of utilities, driven by factors such as stable earnings, favorable regulatory environments, or improved credit fundamentals.

Q HAS THE FED MADE RECENT COMMENTS CONCERNING MONETARY POLICY AND THE POTENTIAL IMPACT ON INTEREST RATES?

A Yes. On May 7, 2025, the FOMC released the following statement:

> Although swings in net exports have affected the data, recent indicators suggest that economic activity has continued to expand at a solid pace. The unemployment rate has stabilized at a low level in recent months, and labor market conditions remain solid. Inflation remains somewhat elevated.
>
> The Committee seeks to achieve maximum employment and inflation at the rate of 2 percent over the longer run. Uncertainty about the economic outlook has increased further. The Committee is attentive to the risks to both sides of its dual mandate and judges that the risks of higher unemployment and higher inflation have risen.
>
> In support of its goals, the Committee decided to maintain the target range for the federal funds rate at 4-1/4 to 4-1/2 percent. In considering the extent and timing of additional adjustments to the target range for the federal funds rate, the Committee will carefully assess incoming data, the evolving outlook, and the balance of risks. The Committee will continue reducing its holdings of Treasury securities and agency debt and agency mortgage-backed securities. The Committee is strongly committed to supporting maximum employment and returning inflation to its 2 percent objective.
>
> In assessing the appropriate stance of monetary policy, the Committee will continue to monitor the implications of incoming information for the economic outlook. The Committee would be prepared to adjust the stance of monetary policy as appropriate if risks emerge that could impede the attainment of the Committee's goals. The Committee's assessments will take into account a wide range of information, including

readings on labor market conditions, inflation pressures and inflation expectations, and financial and international developments.[2]

The Fed's May 7, 2025, FOMC statement indicates that economic activity continues to expand at a solid pace, with labor market conditions remaining strong and inflation somewhat elevated. However, the Committee noted increased uncertainty about the economic outlook, citing heightened risks of both higher unemployment and higher inflation. To support its dual mandate of maximum employment and 2% inflation, the Fed maintained the federal funds rate target range at 4.25% to 4.5%. The Committee also decided to continue reducing its holdings of Treasury securities and agency debt and mortgage-backed securities, with Treasury redemptions capped at $5 billion per month and agency securities at $35 billion per month. The Fed emphasized its commitment to monitoring incoming data and is prepared to adjust monetary policy as appropriate to achieve its goals.

Q WHAT DO INDEPENDENT ECONOMISTS' OUTLOOKS FOR FUTURE INTEREST RATES AND INFLATION LEVELS INDICATE?

A Independent economists, surveyed by *Blue Chip Financial Forecasts,* expect long-term bond yields to remain relatively flat to marginally increase over the near term, while maintaining levels that are still relatively low by historical levels. For example, independent projections show that the consensus is the federal funds rate will decrease while long-term interest rates, as measured by the 30-year Treasury bond, are expected to remain relatively flat. Inflation, as measured through the Gross Domestic

[2] Federal Reserve Board - Federal Reserve issues FOMC statement, May 7, 2025.

Product ("GDP") price index, is expected to be a mix of marginal increases and decreases over the near to intermediate term. This indicates that levels of inflation are expected to be relatively flat over that period. The consensus projections for the next several quarters are provided in Table CCW-3 below.

TABLE CCW-3

Blue Chip Financial Forecasts
Projected Federal Funds Rate, 30-Year Treasury Bond Yields, and GDP Price Index

Publication Date	2Q 2024	3Q 2024	4Q 2024	1Q 2025	2Q 2025	3Q 2025	4Q 2025	1Q 2026	2Q 2026	3Q 2026
T-Bond, 30 yr.										
Jul-24	4.6	4.5	4.4	4.4	4.3	4.3	4.2			
Aug-24	4.6	4.5	4.4	4.4	4.3	4.3	4.3			
Sep-24	**4.6**	4.2	4.2	4.1	4.1	4.1	4.1			
Oct-24		4.2	4.1	4.0	4.0	4.0	4.1	4.0		
Nov-24		4.2	4.3	4.2	4.2	4.2	4.2	4.2		
Dec-24		**4.2**	4.5	4.5	4.4	4.4	4.4	4.4		
Jan-25			4.5	4.6	4.5	4.5	4.5	4.5	4.4	
Feb-25			4.5	4.7	4.7	4.7	4.7	4.6	4.6	
Mar-25			**4.5**	4.7	4.7	4.7	4.6	4.6	4.6	
Apr-25				4.7	4.6	4.6	4.5	4.5	4.5	4.5
May-25				4.7	4.6	4.5	4.5	4.4	4.4	4.4
Jun-25				**4.7**	4.8	4.7	4.6	4.6	4.6	4.5
GDP Price Index										
Jul-24	2.8	2.3	2.3	2.4	2.2	2.2	2.1			
Aug-24	2.3	2.3	2.3	2.3	2.2	2.2	2.1			
Sep-24	**2.5**	2.2	2.2	2.3	2.2	2.2	2.1			
Oct-24		2.2	2.0	2.2	2.2	2.1	2.1	2.1		
Nov-24		1.8	2.1	2.2	2.1	2.1	2.1	2.2		
Dec-24		**1.8**	2.2	2.3	2.2	2.2	2.3	2.3		
Jan-25			2.2	2.3	2.4	2.4	2.5	2.6	2.1	
Feb-25			2.2	2.5	2.5	2.5	2.5	2.5	2.1	
Mar-25			**2.4**	2.7	2.5	2.5	2.5	2.5	2.2	
Apr-25				2.7	2.7	2.7	2.5	2.5	2.1	2.2
May-25				3.7	3.4	3.2	2.9	2.6	2.3	2.3
Jun-25				**3.7**	2.9	3.4	2.8	2.6	2.2	2.3

Source and Note:
Blue Chip Financial Forecasts, July 2024 through June 2025.
Actual Yields in Bold.

Q WHAT IS THE OUTLOOK FOR LONG-TERM INTEREST RATES, AND WHY DOES IT MATTER?

A The outlook for long-term interest rates in the intermediate to long-term is also impacted by the current Fed actions and the expectation that eventually the Fed's monetary actions will return to more normal levels.

Long-term interest rate projections are illustrated in Table CCW-4:

TABLE CCW-4

30-Year Treasury Bond Yield Actual Vs. Projection

Description	Actual	Near-Term Projected*	5- to 10-Year Projected
2020			
Q1	1.88%	2.57%	
Q2	1.38%	1.90%	3.0% - 3.8%
Q3	1.36%	1.87%	
Q4	1.62%	1.97%	2.8% - 3.6%
2021			
Q1	2.07%	2.23%	
Q2	2.26%	2.77%	3.5% - 3.9%
Q3	1.93%	2.63%	
Q4	1.95%	2.70%	3.4% - 3.8%
2022			
Q1	2.25%	2.87%	
Q2	3.04%	3.47%	3.8% - 3.9%
Q3	3.26%	3.63%	
Q4	3.90%	3.87%	3.9% - 4.0%
2023			
Q1	3.74%	3.77%	
Q2	3.80%	3.70%	3.8% - 3.9%
Q3	4.24%	3.83%	
Q4	4.58%	4.17%	4.1% - 4.2%
2024			
Q1	4.33%	4.03%	
Q2	4.57%	4.17%	4.3% - 4.4%
Q3	4.22%	4.20%	
Q4	4.50%	4.20%	4.3% - 4.2%
2025			
Q1	4.71%	4.53%	

Source and Note:
Blue Chip Financial Forecasts, January 2019 through June 2025.
*Average of all 3 reports in Quarter.

As outlined in Table CCW-4, the outlook for interest rates has moderated more recently relative to 2020 and part of 2021. For example, when actual interest rates were in the range of 1.4% to 2.1%, the near-term projections for 30-year Treasury yields ranged from 1.9% to 2.8% in 2020-2021, while the projections five to ten years out were in the range of 2.8% to 3.9%. Most recently, actual interest rates were approximately 4.5%, with near and intermediate projections in the range of 4.2% to 4.3%. While interest rates were expected to increase drastically from their actual levels in the 2020-2021 period, those same projections are now flat to declining, which indicates the cost of long-term capital might be near its peak.

C. Market Sentiments and Utility Industry Outlook

Q PLEASE DESCRIBE THE CREDIT RATING OUTLOOK FOR REGULATED UTILITIES.

A All credit rating agencies see rate affordability as an important consideration in assessing utility credit, including Standard & Poor's ("S&P") and Moody's Investors Service ("Moody's") as discussed below.

In its 2025 Outlook,[3] S&P reports that North American regulated utilities face continued credit pressure due to elevated capital spending, persistent cash flow deficits (exceeding $100 billion), and increasing physical risks such as wildfires and extreme weather. In 2024, downgrades again outpaced upgrades, a five-year trend driven by high capex, rising wildfire risk, and uneven regulatory outcomes. Despite ongoing investment in the energy transition and data center growth (which may modestly lift

[3]S&P Global Credit Ratings, "Industry Credit Outlook 2025 – North America Regulated Utilities", January 14, 2025.

electricity sales by ~1% annually), financial metrics are deteriorating due to underwhelming common equity issuance and high leverage. Hybrid security issuance hit a record $26 billion in 2024 and is expected to continue helping credit support. Regulatory frameworks remain broadly credit supportive, though S&P downgraded its view of Connecticut due to inconsistent returns and rising lag. Customer bill affordability remains a key consideration, especially as capacity prices rise and new infrastructure costs must be equitably allocated. Wildfire risk—particularly litigation and insurance constraints—is becoming a systemic credit concern, now affecting nearly all regions. S&P made several specific observations about affordability in the context of regulated utilities' credit quality:

1. Electric bills as a share of household income: S&P noted that the average electric customer bill is about 2% of U.S. median household income, which it characterizes as "good value" relative to other typical household expenses. Preserving this affordability is critical to maintaining the industry's credit quality, as it underpins public and regulatory support.

2. Risk from cost shifts due to data centers: S&P cautioned that if utilities assign a significant portion of new infrastructure costs related to data center growth to existing residential customers, it could lead to higher customer bills. This would, in turn, pressure regulators to limit future rate case increases, potentially impairing utilities' ability to recover costs or earn authorized returns.

3. Capacity price increases: S&P warned that higher PJM capacity prices—which are directly passed on to customers—could result in greater customer dissatisfaction. This could prompt regulators to limit increases in other parts of the customer bill, indirectly constraining utilities' ability to maintain financial performance and manage regulatory risk.

In sum, S&P views affordability as a cornerstone issue for the sector: sustained rate increases or cost shifts that threaten affordability could erode regulatory support, triggering credit risk.

In a recent industry report, Moody's explained that the regulated electric and gas utilities' outlook remains "Negative" largely due to increased pricing pressures on customers. Moody's stated that it changed its outlook from "Stable" to "Negative" due to the following:

> We have revised our outlook on the US regulated utilities sector to negative from stable. We changed the outlook because of increasingly challenging business and financial conditions stemming from higher natural gas prices, inflation and rising interest rates. These developments raise residential customer affordability issues, increasing the level of uncertainty with regard to the timely recovery of costs for fuel and purchased power, as well as for rate cases more broadly.[4]

Also, in a report published in January of 2024, S&P specifically mentioned commodity price volatility, in combination with significant increases in capital investments, driving utility rate increases which may strain affordability concerns.[5]

Finally, Fitch opined that the regulated electric and gas utilities' outlook is deteriorating due to elevated capex that put pressure on credit metrics. Fitch also notes the bill affordability concerns for ratepayers, and regulators' ability to balance the rate requests with increasing customer bills.

Specifically, Fitch states:

> Fitch Ratings' deteriorating outlook for the North American Utilities, Power & Gas sector reflects continuing macroeconomic headwinds and elevated capex that are putting pressure on credit metrics in the high-cost funding environment. Bill affordability concerns for ratepayers continue to persist despite the pull back in natural gas prices and inflationary pressures. Fitch expects utility capex to grow by double digits in 2024, underpinned by investments needed to make the electric infrastructure more resilient against extreme weather events and to accommodate renewable generation, including distributed sources. Rate case outcomes

[4] *Moody's Investors Service Outlook*: "Regulated Electric and Gas Utilities – US 2023 outlook negative due to higher natural gas prices, inflation and rising interest rates," November 10, 2022 at page 1. (Emphasis Added).

[5] *S&P Global Ratings*: "Industry Credit Outlook 2024: North America Regulated Utilities," January 9, 2024 at page 8.

> are key to watch as regulators balance more rate requests with increases in customer bills. Authorized ROEs could prove to be sticky despite an increase in cost of capital. Higher weather-normalized retail electricity sales, driven by datacenter growth and onshoring of manufacturing activities, and tax transferability provisions of the Inflation Reduction Act could somewhat offset headwinds to utilities. Ongoing management actions to sell assets and issue equity, in some cases, is supportive of parent companies' ratings. Within Fitch's coverage, 90% of ratings hold Stable Rating Outlooks. We expect limited rating movement in 2024. The number of upgrades in 2023 so far exceeds the number of downgrades, and is driven by positive rating actions on several parent holding companies and their regulated subsidiaries.[6]

As outlined by Moody's, S&P, and Fitch above, credit analysts are focusing on rate affordability as an important factor needed to support strong credit standing. Customers must be able to afford to pay their utility bills in order for utilities to maintain their financial integrity and strong investment grade credit standing. For this reason, this Commission should carefully assess the reasonableness of cost of service in this proceeding, including an appropriate overall ROR necessitated by a reasonably cost-effective balanced ratemaking capital structure, and a ROE that represents fair compensation but also maintains competitive, just, and reasonable rates.

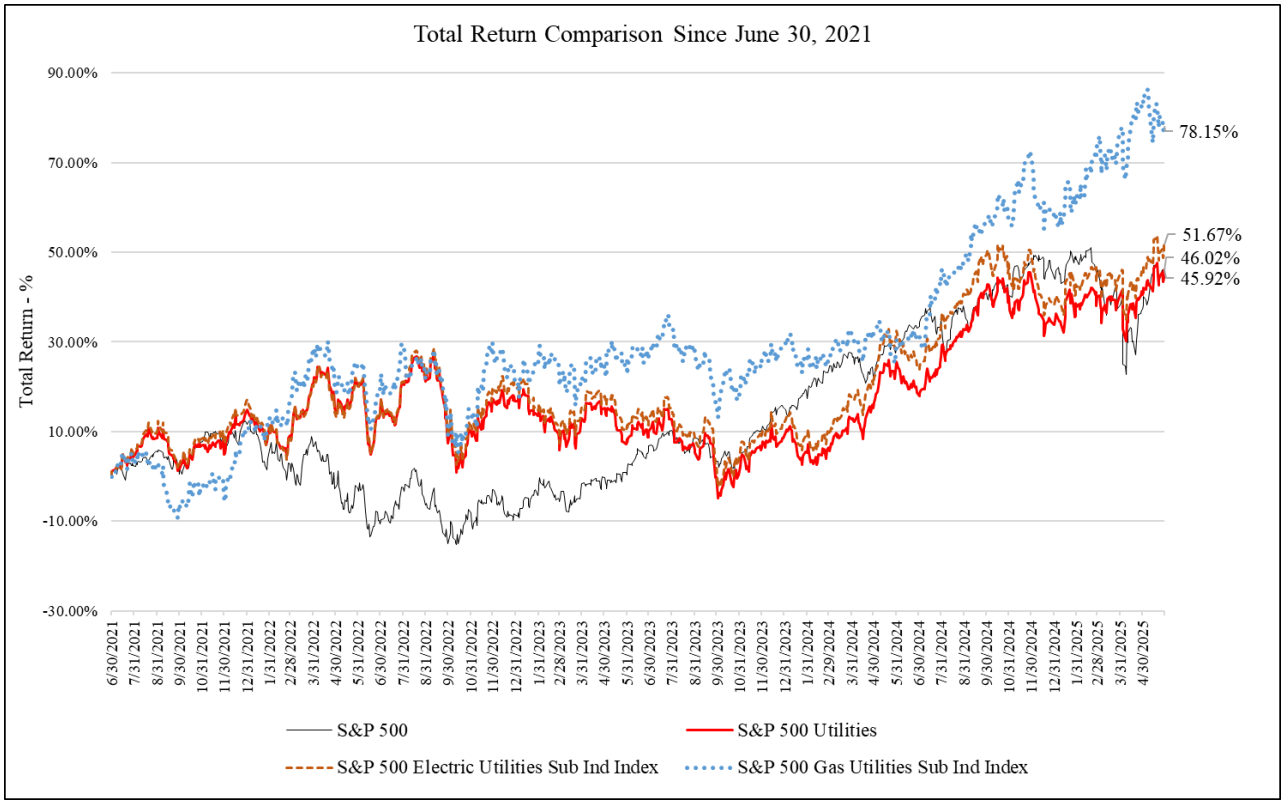
[6] *FitchRatings.* "North American Utilities, Power & Gas Outlook 2024," December 6, 2023 at page 1. (Emphasis Added).

D. Additional Remarks

Q IN LIGHT OF HIGHER LEVELS OF INFLATION, EXPECTATIONS OF HIGHER INTEREST RATES, AND GEOPOLITICAL EVENTS AROUND THE WORLD, HOW HAS THE MARKET PERCEIVED UTILITIES AS INVESTMENT OPTIONS?

A Since the beginning of the second half of 2021, the natural gas utility sector has significantly outperformed the S&P 500, with a total return of 78.15% compared to the market's total return of 45.92%. Similarly, the electric utility sector has also outperformed the broader market with a total return of 51.67% over the same period, as shown in Figure CCW-4 below.

Figure CCW-4



It is important to note that the S&P 500's strong performance in 2023 and early 2024 was largely driven by a small group of "mega-cap" companies known as the Magnificent 7. The Magnificent 7's stocks were among the most valuable companies in the S&P 500 index and rallied significantly over this time. Those seven stocks accounted for a majority of the S&P 500's returns even though there were 493 other companies in the index. This is because the S&P 500 is a market capitalization-weighted index, meaning companies with larger market capitalizations have a greater impact on the index's overall performance. This is explained in the S&P Dow Jones Indices report "U.S. Equity Market Attributes April 2024," stating that:

> Year-to-date, the S&P 500 remained up 5.57% (with 10 of the 11 sectors up; Real Estate was down 9.86%), as breadth declined but remained positive (302 up and 199 down, compared to last March's 369 and 134 YTD, respectively). The Magnificent 7 as a group still dominated, accounting for 51% of the index return (which included Apple's 11.5% YTD decline and Tesla's 26.2% YTD decline), as NVIDIA (up 74.5% YTD) represented 41% of the S&P 500's YTD gain.[7]

While the S&P 500's strong performance in 2023 and early 2024 was largely driven by a small group of "mega-cap" technology companies known as the Magnificent 7, the utility sector demonstrated positive and relatively stable returns over this period. This reflects the defensive characteristics of regulated utilities, which are often viewed by investors as safer assets during times of macroeconomic and geopolitical uncertainty. Utilities' essential service nature, predictable cash flows, and supportive regulatory environments helped them remain attractive to investors even amid elevated inflation, rising interest rates, and global instability.

[7]S&P Dow Jones Indices, "Market Attributes: U.S. Equities April 2024". (Emphasis Added).

III. RATE OF RETURN

Q PLEASE GENERALLY DESCRIBE WHAT IS MEANT BY THE OVERALL ROR AS IT RELATES TO RATEMAKING FOR REGULATED UTILITIES.

A The overall ROR in utility ratemaking represents the weighted average cost of capital a utility is allowed to earn on its rate base. It combines the cost of debt and the authorized ROE, weighted by the utility's capital structure.

A. Capital Structure

Q WHAT ARE THE COMPANIES' PROPOSED CAPITAL STRUCTURE?

A The Companies' proposed capital structure is summarized in Table CCW-5 below:

Table CCW-5

Investor-Supplied Capital Structure

Description	Weight
Long-term Debt	51.06%
Common Equity	48.94%
Total	100.00%[8]

*Total may not add due to rounding

Q DO YOU HAVE ANY COMMENTS ON THE COMPANIES' PROPOSED CAPITAL STRUCTURE?

A Yes. As shown, the Companies' proposed equity ratio of 48.94% is relatively higher than the equity ratio for the proxy group used to estimate the cost of equity for the

[8] *See,* Joint Statement No. 2A at 4.

Companies. As shown on Exhibit CCW-2, the proxy group has an average common equity ratio of 40.4% (including short-term debt) and 44.6% (excluding short-term debt). However, because the Companies do not access external capital on their own, and the actual equity ratios are unreasonable for ratemaking purposes, the Companies' proposal to use the actual capital structure of the parent company, C&T Enterprises, is reasonable and should be used.

B. Cost of Debt

Q WHAT COST OF DEBT ARE THE COMPANIES PROPOSING?

A The Companies are proposing an embedded cost of long-term debt of 5.03% (Valley), 5.47% (Citizens) and 4.85% (Wellsboro).

Q ARE YOU TAKING ISSUE WITH THE COMPANIES' PROPOSED COST OF DEBT?

A No, I am not.

C. Cost of Equity

Q PLEASE DESCRIBE WHAT IS MEANT BY A "UTILITY'S COST OF COMMON EQUITY."

A A utility's cost of common equity is the expected return that investors require on an investment in the utility. Investors expect to earn their required return from receiving dividends and through stock price appreciation. This rate is designed to ensure the utility can attract investment, maintain financial stability, and provide reliable service

while balancing the interests of shareholders and ratepayers. Regulatory commissions set the ROE based on market conditions and the utility's specific risk profile.

Q PLEASE DESCRIBE THE FRAMEWORK FOR DETERMINING A REGULATED UTILITY'S COST OF COMMON EQUITY.

A In general, determining a fair cost of common equity for a regulated utility has been framed by two hallmark decisions of the U.S. Supreme Court ("Supreme Court"): Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n of W. Va., 262 U.S. 679 (1923) and Fed. Power Comm'n v. Hope Natural Gas Co., 320 U.S. 591 (1944). In these decisions, the Supreme Court found that just compensation depends on many circumstances and must be determined by fair and enlightened judgments based on relevant facts. The Supreme Court also found that a utility is entitled to such rates as would permit it to earn a return on a property devoted to the convenience of the public that is generally consistent with the same returns available in other investments of corresponding risk. The Supreme Court continued that the utility has "no constitutional rights to profits" such as those "realized or anticipated in highly profitable enterprises or speculative ventures,"[9] and defined the ratepayer/investor balance as follows:

> The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties.[10]

As such, a fair ROR is based on the expectation that the utility's costs reflect efficient and economical management, and the return will support its credit standing

[9] *Bluefield,* 262 U.S. at pages 692-693.
[10] *Id*. at 693 (Emphasis Added).

and access to capital, but the return will not be in excess of this level. Utility rates that are consistent with these standards will be just and reasonable, and compensation to the utility will be fair and support financial integrity and credit-standing, under economic management of the utility.

Q PLEASE DESCRIBE THE PROCESS YOU HAVE USED TO ESTIMATE THE COMPANIES' COST OF COMMON EQUITY.

A First, I assess the market's perspective of the Companies' risk. Then, I developed a proxy group of publicly traded utility companies that have similar risks and characteristics to the Companies and compared potential differences in risks. I then perform several models based on financial theory to estimate the Companies' cost of common equity. These models are: (1) a constant growth Discounted Cash Flow ("DCF") model using consensus analysts' growth rate projections; (2) a constant growth DCF model using sustainable growth rate estimates; (3) a multi-stage growth DCF model; (4) a Risk Premium method; and (5) a Capital Asset Pricing Model ("CAPM").

Q WHY MUST THE COST OF EQUITY BE ESTIMATED RATHER THAN DIRECTLY OBSERVED?

A The cost of equity cannot be directly observed because equity investors do not receive fixed, contractual payments like debt holders do. Instead, they are compensated through uncertain and variable returns in the form of dividends and capital appreciation. These returns depend on a range of unpredictable factors, including company performance,

market conditions, and investor sentiment. As such, the cost of equity represents an investor's required ROR, which must be estimated using financial models rather than measured directly from observable market transactions.

Q WHY IS IT NECESSARY TO APPLY MULTIPLE METHODS TO ESTIMATE THE COST OF EQUITY?

A Because the cost of equity is an estimate based on forward-looking expectations and assumptions, no single model can definitively or universally capture the "true" cost. Each model, such as the DCF model, the CAPM, and the Risk Premium approach, has its own theoretical foundation, strengths, and limitations. These models rely on different assumptions and input variables such as projected growth rates or equity risk premiums which can vary in reliability. Using multiple models provides a more comprehensive and balanced view, helps identify outlier results, and increases confidence that the final estimate reasonably reflects investor expectations under current market conditions.

Q DOES THE USE OF MULTIPLE METHODS IMPROVE THE ACCURACY OF THE ESTIMATE?

A Yes. Employing multiple methods helps to cross-check and validate the results, mitigate the impact of any one model's limitations or potentially flawed assumptions, and reduce reliance on any single uncertain input. By considering results from different perspectives, a more informed and credible estimate can be made. This approach is

consistent with both sound financial practice and regulatory expectations for fair and reasonable return determinations.

D. Investment Risk Assessment of the Companies

Q PLEASE DESCRIBE THE MARKET'S ASSESSMENT OF THE COMPANIES' INVESTMENT RISK.

A The market's assessment of a company's investment risk is generally best described by credit rating analysts' reports.

E. Development of Proxy Group

Q PLEASE BRIEFLY DESCRIBE WHY A PROXY GROUP IS NEEDED IN ESTIMATING THE COST OF EQUITY.

A There are a few reasons why a proxy group is needed to estimate the cost of equity. As an initial matter, to be consistent with the *Hope* and *Bluefield* standards, as described above, the allowed return should be commensurate with returns on investments in other forms of comparable risk. A proxy group of similarly situated companies of comparable risk is needed to assess the Companies' proposal under this standard.

Even if the Companies were a publicly traded company whose securities could be used to estimate its cost of equity, there exists the potential for certain errors and biases which would make the reliance on a single estimate undesirable and potentially less accurate. A proxy group of comparable risk companies adds reliability to the estimates by mitigating the potential for bias that may be introduced by measurement errors of model inputs.

Q PLEASE DESCRIBE HOW YOU IDENTIFIED A PROXY UTILITY GROUP THAT COULD BE USED TO ESTIMATE THE COMPANIES' CURRENT MARKET COST OF EQUITY.

A I started with the same utility company proxy group relied on by the Companies' Witness. I then reviewed each company to see if there were any significant factors that would potentially impact the overall risk level. Such factors would include significant merger and/or acquisition activity, credit ratings upgrades/downgrades, or dividend cuts. I also reviewed to make sure they were covered by an analyst in the *Value Line Investment Survey*. Based on my review, I found that the Companies' Witness' initial proxy group was sufficient with the exception of one company: TXNM Energy. On May 19, 2025, TXNM Energy announced that they had reached a definitive agreement to be acquired by Blackstone Infrastructure Partners for approximately $11.94 billion. Because TXNM Energy is party to a significant transaction, it must be excluded.

Q HOW DOES THE INVESTMENT RISK OF THE COMPANIES COMPARE TO THAT OF THE PROXY GROUP?

A As shown on my Exhibit CCW-2, the proxy group has average credit ratings of BBB+ and Baa1 from S&P and Moody's, respectively. The Companies are not rated entities by the major ratings agencies. However, they only operate in Pennsylvania, and Pennsylvania has a regulatory assessment of "Highly Credit Supportive" from S&P Global Ratings Direct. In my opinion, the Companies would be rated comparatively at worst, if not higher than the proxy group.

As shown on the same exhibit, the proxy group has an average common equity ratio of 40.4% (including short-term debt) and 44.6% (excluding short-term debt) as calculated by *S&P Global Market Intelligence* and *Value Line*, respectively. The Companies' Witness' proposed common equity ratio of 48.94% for the Companies is marginally higher than the proxy group's equity ratio as described above, but not excessive for ratemaking. As described by the Companies' Witness, the actual equity ratios for the Companies are 69.9%, 86.6%, and 20.5% for Valley, Citizens, and Wellsboro, respectively.

F. DCF Model

Q PLEASE DESCRIBE THE DCF MODEL.

A The DCF model posits that a stock price equals the sum of the present value of expected future cash flows discounted at the investor's required ROR or cost of capital.

This model is expressed mathematically as follows:

$$P_0 = \frac{D_1}{(1+K)^1} + \frac{D_2}{(1+K)^2} + \ldots . \frac{D_\infty}{(1+K)^\infty} \qquad \text{(Equation 1)}$$

P_0 = Current stock price
D = Dividends in periods 1 - ∞
K = Investor's required return

This model can be rearranged in order to estimate the discount rate or investor-required return, known as "K." If it is reasonable to assume that earnings and dividends will grow at a constant rate, then Equation 1 can be rearranged as follows:

$$K = D_1/P_0 + G \qquad \text{(Equation 2)}$$

K = Investor's required return
D_1 = Dividend in first year
P_0 = Current stock price
G = Expected constant dividend growth rate

Equation 2 is referred to as the annual "constant growth" DCF model.

Q PLEASE DESCRIBE THE INPUTS TO YOUR CONSTANT GROWTH DCF MODEL.

A As shown in Equation 2 above, the DCF model requires a current stock price, the expected dividend, and the expected growth rate in dividends.

Q WHAT STOCK PRICE HAVE YOU RELIED ON IN YOUR CONSTANT GROWTH DCF MODEL?

A I relied on the average of the weekly high and low stock prices of the utilities in the proxy group over a 13-week period ending on May 30, 2025. An average stock price is less susceptible to market price variations than a price at a single point in time. Therefore, an average stock price is less susceptible to aberrant market price movements, which may not reflect the stock's long-term value.

Q WHAT DIVIDEND DID YOU USE IN YOUR CONSTANT GROWTH DCF MODEL?

A I used each proxy company's most recently paid quarterly dividend as reported in *Value Line*.[11] This dividend was annualized (multiplied by 4) and adjusted for next year's growth to produce the D_1 factor for use in Equation 2 above. In other words, I calculate D_1 by multiplying the annualized dividend (D_0) by (1+G).

Q WHAT DIVIDEND GROWTH RATES HAVE YOU USED IN YOUR CONSTANT GROWTH DCF MODEL?

A There are several methods that can be used to estimate the expected growth in dividends. However, regardless of the method, for purposes of determining the market-required return on common equity, one must attempt to estimate investors' expectations about what the dividend, or earnings growth rate, will be, and not what an individual investor or analyst may use to make individual investment decisions.

As predictors of future returns, securities analysts' growth estimates have been shown to be more accurate than growth rates derived from historical data.[12] That is, assuming the market generally makes rational investment decisions, analysts' growth projections are more likely to influence investors' decisions, which are captured in observable stock prices, than growth rates derived only from historical data.

For my constant growth DCF analysis, I have relied on a consensus, or mean, of professional securities analysts' earnings growth estimates as a proxy for investors'

[11]The *Value Line Investment Survey*, March 7, April 18, May, 9, and May 23, 2025.

[12]*See*, e.g., David Gordon, Myron Gordon, and Lawrence Gould, Choice Among Methods of Estimating Share Yield, The Journal of Portfolio Management, Spring 1989.

dividend growth rate expectations. I used the average of analysts' growth rate estimates from three sources: Zacks, S&P Capital IQ Market Intelligence ("MI"), and Institutional Brokers' Estimate System ("I/B/E/S") from LSEG Workspace. All such projections were available on May 30, 2025, and all were reported online.[13]

Each growth rate projection is based on a survey of independent securities analysts. There is no clear evidence whether a particular analyst is most influential on general market investors. Therefore, a single analyst's projection does not predict investor outlooks as reliably as does a consensus of market analysts' projections. The consensus of estimates is a simple arithmetic average, or mean, of surveyed analysts' earnings growth forecasts. A simple average of the growth forecasts gives equal weight to all surveyed analysts' projections. Therefore, a simple average, or arithmetic mean, of analysts' forecasts is a good proxy for investor expectations.

The growth rates I used in my DCF analysis are shown in Exhibit CCW-3. The average growth rate for my proxy group is 6.87% and a median growth rate of 6.70%.

Q WHAT ARE THE RESULTS OF YOUR CONSTANT GROWTH DCF MODEL?

A As shown in Exhibit CCW-4, page 1, the average and median constant growth DCF returns for my proxy group for the 13-week analysis are 10.79% and 10.31%, respectively.

[13] www.zacks.com; LSEG Workspace; https://www.capitaliq.spglobal.com/.

Q ARE THERE LIMITATIONS OF THE CONSTANT GROWTH DCF ANALYSIS?

A Yes. The constant growth DCF analysis for my proxy group is based on a group average long-term growth rate of 6.87%. The three- to five-year growth rates are approximately 68% higher than the long-term projected GDP growth rate of 4.09%, described below. As I explain in detail below, a utility's growth rate cannot exceed the growth rate of the economy in which it provides services in perpetuity, which is the time period assumed by the DCF model.

Q HOW DID YOU IDENTIFY THE LONG-TERM PROJECTED GDP GROWTH RATE?

A Although there may be short-term peaks, the long-term sustainable growth rate for a utility stock cannot exceed the growth rate of the economy in which it sells its goods and services. The long-term maximum sustainable growth rate for a utility investment is limited by the projected long-term GDP growth rate, as that reflects the projected long-term growth rate of the economy. The consensus projection for U.S. GDP, as published by Blue Chip Financial Forecasts, is an annual growth rate of approximately 4.09% over the next 10 years. In my opinion, this is a reasonable proxy of long-term growth.

Later in this testimony, I discuss academic and investment-practitioner support for using the projected long-term GDP growth outlook as a maximum long-term growth rate projection. Using the long-term GDP growth rate as a conservative projection for

the maximum growth rate is logical and is generally consistent with academic and practitioner accepted practices.

G. Sustainable Growth DCF

Q PLEASE DESCRIBE WHAT THE SUSTAINABLE GROWTH DCF METHOD IS AND HOW YOU ESTIMATED A SUSTAINABLE GROWTH RATE FOR YOUR SUSTAINABLE GROWTH DCF MODEL.

A The sustainable growth rate, also referred to as the internal growth rate, is determined by the proportion of the utility's earnings that is retained and reinvested in its plant and equipment. These reinvested earnings enhance the earnings base, also known as the rate base. The earnings grow as the plant, funded by the reinvested earnings, is put into operation, allowing the utility to receive its authorized return on the additional rate base investment.

The internal growth approach is linked to the percentage of earnings retained within a company, as opposed to being paid out as dividends. The earnings retention ratio is calculated as 1 minus the dividend payout ratio. As the payout ratio decreases, the retention ratio increases, leading to stronger growth as a company funds more investments using retained earnings.

The payout ratios of the proxy group are shown in my Exhibit CCW-5. These dividend-payout ratios and earnings-retention ratios then can be used to develop a long-term growth rate driven by earnings retention.

The data used to estimate the long-term sustainable growth rate is based on the Companies' current market-to-book ratio and on *Value Line*'s three-to-five year projections of earnings, dividends, earned returns on book equity, and stock issuances.

As shown in Exhibit CCW-6, the average and median sustainable growth rates for the proxy group using this internal growth rate model are 4.46% and 4.20%, respectively.

Q WHAT IS THE DCF ESTIMATE USING THESE SUSTAINABLE GROWTH RATES?

A A DCF estimate based on these sustainable growth rates is developed in Exhibit CCW-7. As shown there, and using the same formula in Equation 2 above, a sustainable growth DCF analysis produces proxy group average and median DCF results for the 13-week period of 9.59% and 9.57%, respectively.

H. Multi-Stage Growth DCF Model

Q HAVE YOU CONDUCTED ANY OTHER DCF STUDIES?

A Yes. As previously noted, the DCF model is intended to represent the present value of an endless series of future cash flows. Nevertheless, the initial constant growth DCF that I created is based on analysts' growth-rate projections, providing a plausible representation of rational investment expectations over the next three-to-five years. The limitation of this constant growth DCF model is that it cannot reflect a reasonable expectation of a shift in growth from a high or low short-term rate to a rate that aligns more with long-term sustainable growth. To accommodate changing growth

expectations, I conducted a multi-stage DCF analysis that reflects growth rate change over time.

Q WHY DO YOU BELIEVE GROWTH RATES CAN CHANGE OVER TIME?

A The growth rate projections by analysts for the next three-to-five years are subject to change as the outlook for utility earnings-growth evolves. Utility companies experience fluctuations in their investment cycles. When these companies are undertaking substantial investments, the growth of their rate base accelerates, leading to an increase in earnings growth. However, once a major construction cycle reaches completion or plateaus, the growth in the utility rate base slows down, and its earnings growth rate declines from an abnormally high three-to-five-year rate to a lower, sustainable growth rate.

As construction cycles become longer in duration, even with an aggressive construction plan, the growth rate of the utility will naturally slow due to a decrease in rate base growth as the utility has limited human and capital resources to expand its construction activities. Therefore, the three-to-five-year growth rate projection should be viewed as a long-term sustainable growth rate, but not without considering the current market conditions, industry trends, and determining whether the three-to-five-year growth outlook is feasible and sustainable.

Q PLEASE DESCRIBE YOUR MULTI-STAGE DCF MODEL.

A The multi-stage DCF model reflects the possibility of non-constant growth for a company over time. The multi-stage DCF model reflects three growth periods: (1) a

short-term growth period consisting of the first five years; (2) a transition period, consisting of the next five years (6 through 10); and (3) a long-term growth period starting in year 11 and extending into perpetuity.

For the short-term growth period, I relied on the consensus of analysts' growth projections described above in relationship to my constant growth DCF model. For the transition period, the growth rates were reduced or increased by an equal factor reflecting the difference between the analysts' growth rates and the long-term sustainable growth rate. For the long-term growth period, I assumed each company's growth would converge to the maximum sustainable long-term growth rate.

Q WHY IS THE GDP GROWTH PROJECTION A REASONABLE PROXY FOR THE MAXIMUM SUSTAINABLE LONG-TERM GROWTH RATE?

A As discussed above, utilities cannot indefinitely sustain a growth rate that exceeds the growth rate of the economy in which they sell services. A utility's earnings and dividend growth is created by increased utility investment in its rate base. Examples of what can drive such investment are: service area economic growth, system reliability upgrades, or state and federal green energy initiatives. As such, nominal GDP growth is a reasonable upper limit for utility sales growth, rate base growth, and earnings growth in the long-run. Therefore, the U.S. GDP nominal growth rate is a conservative proxy for the highest sustainable long-term growth rate of a utility.

Q IS THERE RESEARCH THAT SUPPORTS YOUR POSITION THAT, OVER THE LONG-TERM, A COMPANY'S EARNINGS AND DIVIDENDS CANNOT GROW AT A RATE GREATER THAN THE RATE OF GROWTH OF THE U.S. GDP?

A Yes. This concept is supported in published analyst literature and academic work. Specifically, in a textbook titled *Fundamentals of Financial Management*, published by Eugene Brigham and Joel F. Houston, the authors state as follows:

> The constant growth model is most appropriate for mature companies with a stable history of growth and stable future expectations. Expected growth rates vary somewhat among companies, but dividends for mature firms are often expected to grow in the future at about the same rate as nominal gross domestic product (real GDP plus inflation).[14]

The use of the economic growth rate is also supported by investment practitioners as outlined as follows:

> **Estimating Growth Rates**
>
> One of the advantages of a three-stage discounted cash flow model is that it fits with life cycle theories in regards to company growth. In these theories, companies are assumed to have a life cycle with varying growth characteristics. Typically, the potential for extraordinary growth in the near term eases over time and eventually growth slows to a more stable level.
>
> * * *
>
> Another approach to estimating long-term growth rates is to focus on estimating the overall economic growth rate. Again, this is the approach used in the *Ibbotson Cost of Capital Yearbook*. To obtain the economic growth rate, a forecast is made of the growth rate's component parts. Expected growth can be broken into two main parts: expected inflation and expected real growth. By analyzing these components separately, it is easier to see the factors that drive growth.[15]

[14] *Fundamentals of Financial Management*, Eugene F. Brigham and Joel F. Houston, Eleventh Edition 2007, Thomson South-Western, a Division of Thomson Corporation at page 298 (Emphasis Added).

[15] Morningstar, Inc., Ibbotson SBBI 2013 Valuation Yearbook at pages 51 and 52.

Q HOW DID YOU DETERMINE A LONG-TERM GROWTH RATE THAT REFLECTS THE CURRENT CONSENSUS OF INDEPENDENT MARKET PARTICIPANTS?

A I relied on the consensus of long-term GDP growth projections by independent economists. Blue Chip Financial Forecasts publishes the consensus for GDP growth projections twice a year. These projections reflect current outlooks for GDP and are likely to be influential on investors' expectations of future growth outlooks. The consensus of projected GDP growth is about 4.09% over the next 10 years.[16]

Q DO YOU CONSIDER OTHER SOURCES OF PROJECTED LONG-TERM GDP GROWTH?

A Yes, and these alternative sources corroborate the consensus analysts' projections I relied on. Several projections are shown in Table CCW-6.

[16]Blue Chip Financial Forecasts, June 2, 2025, at page 14.

TABLE CCW-6

GDP Forecasts

Source	Projected Period	Real GDP	Inflation	Nominal GDP
Blue Chip Financial Forecasts [1]	5-10 Yrs	2.0%	2.1%	4.1%
EIA - Annual Energy Outlook[2]	26 Yrs	1.8%	2.1%	3.9%
Congressional Budget Office[3]	30 Yrs	1.6%	2.0%	3.7%
Moody's Analytics[4]	31 Yrs	2.0%	2.1%	4.1%
Social Security Administration[5]	76 Yrs	1.6%	2.4%	4.0%
Economist Intelligence Unit[6]	31 Yrs	1.6%	2.3%	3.9%

Sources:

[1]Blue Chip Financial Forecasts, June 2, 2025 at 14.

[2]U.S. Energy Information Administration (EIA), Annual Energy Outlook 2025, April 15, 2025.

[3]Congressional Budget Office, Long-Term Budget Outlook, March 27, 2025.

[4]Moody's Analytics Forecast, last updated January 13, 2025.

[5]Social Security Administration, "2024 OASDI Trustees Report," Table VI.G6. May 6, 2024.

[6]S&P MI, Economist Intelligence Unit, downloaded on March 4, 2025.

As shown in the table above, the real GDP and the inflation fall in the range of 1.6% to 2.0% and 2.0% to 2.4%, respectively. This results in a nominal GDP in the range of 3.7% to 4.1%. Therefore, the nominal GDP growth projections made by these independent sources support my use of 4.09% as a reasonable estimate of market participants' expectations for long-term GDP growth. The real GDP and nominal GDP growth projections made by these independent sources support my use of 4.09% as a reasonable estimate of market participants' expectations for long-term GDP growth.

Q WHAT STOCK PRICE, DIVIDEND, AND GROWTH RATES DID YOU USE IN YOUR MULTI-STAGE DCF ANALYSIS?

A I relied on the same 13-week average stock prices and the most recent quarterly dividend payment data discussed above. For the first stage, I used the consensus of analysts' growth rate projections discussed above in my constant growth DCF model. The first stage covers the first five years, consistent with the time horizon of the securities analysts' growth rate projections. The second stage, or transition stage, begins in year 6 and extends through year 10. The second stage growth transitions the growth rate from the first stage to the third stage using a straight linear trend. For the third stage, or long-term sustainable growth stage, starting in year 11, I used a 4.09% long-term sustainable growth rate based on the consensus of economists' long-term projected nominal GDP growth rate.

Q WHAT ARE THE RESULTS OF YOUR MULTI-STAGE DCF MODEL?

A As shown in Exhibit CCW-8, the average and median DCF ROEs for my proxy group using the 13-week average stock price are 8.62% and 8.39%, respectively.

Q PLEASE SUMMARIZE THE RESULTS FROM YOUR DCF ANALYSES.

A The DCF results are summarized in Table CCW-7. As described above, the results of the constant growth DCF using analysts' growth rates assume an average long-term growth rate of 6.87%, which is approximately 68% higher than the long-term projected GDP growth rate of 4.09%. This is an unsustainable assumption, and likely leads to an overstatement in the cost of equity for a low risk regulated utility. As such, it is my

opinion that primary weight should be given to the sustainable growth and multi-stage models of the DCF while minimal weight should be given to the constant growth DCF model based on three-to-five year analyst growth rates.

Table CCW-7

Summary of DCF Results

	Proxy Group	
Description	**Mean**	**Median**
Constant Growth DCF Model (Analysts' Growth)	10.79%	10.31%
Constant Growth DCF Model (Sustainable Growth)	9.59%	9.57%
Multi-Stage DCF Model	8.62%	8.39%

I. Risk Premium Model

Q PLEASE DESCRIBE YOUR BOND YIELD PLUS RISK PREMIUM MODEL.

A This model is based on the principle that investors require a higher return to assume greater risk. Common equity investments have greater risk than bonds because bonds have more security of payment in bankruptcy proceedings than common equity and the coupon payments on bonds represent contractual obligations. In contrast, companies are not required to pay dividends or guarantee returns on common equity investments. Therefore, common equity securities are riskier than bond securities.

This risk premium model is based on two estimates of an equity risk premium. First, I quantify the difference between regulatory commission-authorized returns on

common equity and contemporary U.S. Treasury bonds. The difference between the authorized return on common equity and the Treasury bond yield is the risk premium. I estimated the risk premium on an annual basis for each year since January 1986. The authorized ROEs were based on regulatory commission-authorized returns for utility companies. Authorized returns are typically based on expert witnesses' estimates of the investor-required return at the time of the proceeding.

The second equity risk premium estimate is based on the difference between regulatory commission-authorized returns on common equity and contemporary "A" rated utility bond yields by Moody's. I selected the period beginning in 1986 because public utility stocks consistently traded at a premium to book value during that period. This is illustrated in Exhibit CCW-9, which shows the market-to-book ratio since 1986 for the utility industry was consistently above a multiple of 1.0x. Over this period, an analyst can infer that authorized ROEs were sufficient to support market prices that at least exceeded book value. This is an indication that commission-authorized returns on common equity supported a utility's ability to issue additional common stock without diluting existing shares. It further demonstrates that utilities were able to access equity markets without a detrimental impact on current shareholders.

Based on this analysis, as shown in Exhibit CCW-10, the average indicated equity risk premium over U.S. Treasury bond yields has been 5.69%. Since the risk premium can vary depending upon market conditions and changing investor risk perceptions, I believe using an estimated range of risk premiums provides the best

method to measure the current return on common equity for a risk premium methodology.

In addition, I assessed the five-year and ten-year rolling average risk premiums over the study period to gauge the variability over time. These rolling average risk premiums mitigate the impact of anomalous market conditions and skewed risk premiums over an entire business cycle. As shown on my Exhibit CCW-10, the five-year rolling average risk premium over Treasury bonds ranged from 4.25% to 7.09%, while the ten-year rolling average risk premium ranged from 4.38% to 6.91%.

As shown on my Exhibit CCW-11, the average indicated equity risk premium over contemporary "A" rated Moody's utility bond yields was 4.34%. The five-year and ten-year rolling average risk premiums ranged from 2.88% to 5.91% and 3.20% to 5.74%, respectively.

Q WHY IS THE TIME PERIOD USED TO DERIVE THESE EQUITY RISK PREMIUM ESTIMATES APPROPRIATE TO FORM ACCURATE CONCLUSIONS ABOUT CONTEMPORARY MARKET CONDITIONS?

A Contemporary market conditions can change dramatically during the period that rates determined in this proceeding will be in effect. A relatively long period of time where stock valuations reflect premiums to book value indicates that the authorized ROEs and the corresponding equity risk premiums were supportive of investors' return expectations and provided utilities access to the equity markets under reasonable terms and conditions. Further, this period is long enough to smooth abnormal market movement that might distort equity risk premiums. While market conditions and risk

premiums do vary over time, this historical period is a reasonable period to estimate contemporary risk premiums.

Q PLEASE EXPLAIN OTHER MARKET EVIDENCE YOU RELIED ON IN DETERMINING AN APPROPRIATE EQUITY RISK PREMIUM.

A The equity risk premium should reflect the market's perception of risk in the utility industry today. I have gauged investor perceptions in utility risk today in Exhibit CCW-12, where I show the yield-spread between utility bonds and Treasury bonds since 1980. As shown in this exhibit, the average utility bond yield-spreads over Treasury bonds for "A" and "Baa" rated utility bonds for this historical period are 1.47% and 1.88%, respectively.

A current three-month average "A" rated utility bond yield of 5.89% when compared to the current Treasury bond yield of 4.74%, as shown in Exhibit CCW-13, page 1, implies a yield-spread of 1.15%. This current utility bond yield-spread is lower than the long-term average-spread for "A" rated utility bonds of 1.47%. The three-month average yield on "Baa" rated utility bonds is 6.08%. This indicates a current spread for the "Baa" rated utility bond yield of 1.34%, which is lower than the long-term average of 1.88%.

Q WHAT DOES THE CURRENT TREND IN UTILITY BOND SPREADS RELATIVE TO TREASURY BONDS INDICATE ABOUT THE MARKET'S PERCEPTION OF UTILITY RISK?

A The decline in the yield spread of utility bonds over Treasury bonds, to levels below historical averages, indicates that the market currently views utilities as relatively low-risk investments. Investors are demanding less additional yield to hold utility bonds, reflecting strong confidence in utilities' financial stability and creditworthiness under current market conditions.

Q HOW IS THE DECLINE IN UTILITY BOND SPREADS RELEVANT TO ESTABLISHING A FAIR ROE FOR UTILITIES?

A The narrowing of utility bond spreads demonstrates that investors require less compensation for utility credit risk today than they have historically. Because the cost of equity must reflect prevailing market conditions, lower perceived risk implies a lower investor-required ROE. A high ROE would overcompensate utilities and burden customers unnecessarily, given that the market clearly prices utilities as safer investments than in the past. This information supports a below-average equity risk premium.

Q WHY SHOULD REGULATORS CONSIDER UTILITY BOND SPREADS WHEN SETTING AN AUTHORIZED ROE?

A Bond spreads provide an objective, real-time market measure of risk that regulators should consider when setting the allowed ROE. If the bond market, which represents

large, sophisticated investors, views utilities as low-risk, it follows that equity investors also perceive lower risk and require a correspondingly lower return. Ignoring this evidence could result in rates that are not just and reasonable for customers.

Q WHAT ARE THE RESULTS BASED ON YOUR RISK PREMIUM ANALYSES?

A I give primary consideration to the Risk Premium results using Treasury bonds and A-rated utility bonds. My recommendation also takes the results of adding the Baa-rated utility bond yield to the equity risk premium over A-rated utility bonds into consideration.

Considering the current and projected economic environment, current yield-spreads and equity risk premiums, as well as current levels of interest rates and interest rate projections, I believe an equity risk premium between the average and most recent two-year average equity risk premiums are warranted. As such, I believe an electric equity risk premium over Treasury yields in the range of 5.32% and 5.69% is appropriate. The midpoint of this risk premium range is 5.50%. Adding this risk premium to the most recent consensus projected Treasury yield of 4.50% produces a ROE of 10.00%. Applying a similar methodology to the gas equity risk premiums shows a long-term average equity risk premium of 5.61% and the recent two-year average of 5.28%. The midpoint of this range for the gas equity risk premium over Treasury yields is 5.44%. Adding the 5.44% gas risk premium to the projected Treasury yield of 4.5% produces a ROE of 9.94%.

Applying a similar methodology as described above, the most recent two-year average equity risk premium over A-rated utility bonds is 4.10%, while the long-term

average risk premium is 4.34%. The midpoint of this risk premium range is 4.22%. Similarly, the long-term average gas equity risk premium over A-rated utility bond yields is 4.26% while the most recent two-year average is 4.06%. The midpoint of the gas equity risk premium range is 4.16%. The A-rated utility bond yield has averaged 5.89% over the three-month period through May 2025 while the Baa-rated utility bond yield has averaged 6.08% over the same period. Adding the indicated equity risk premiums of 4.22% (electric) and 4.16% (gas) to the three-month average A-rated utility bond yield of 5.89% produces cost of equity estimates of 10.11% (electric) and 10.05% (gas). Adding the same equity risk premiums to the three-month average Baa-rated utility bond yield of 6.08% produces cost of equity estimates of 10.30% (electric) and 10.24% (gas).

The A-rated utility bond yield has averaged 5.81% over the six-month period ending May 2025 while the Baa-rated utility bond yield has averaged 6.00% over the same period. Adding the indicated equity risk premiums of 4.22% (electric) and 4.16% (gas) to the six-month average A-rated utility bond yield of 5.81% produces cost of equity estimates of 10.03% (electric) and 9.97% (gas). Adding the same equity risk premium to the six-month average Baa-rated utility bond yield of 6.00% produces cost of equity estimates of 10.22% (electric) and 10.16% (gas).

The results of my risk premium analyses are summarized in Table CCW-8.

Table CCW-8

Summary of Risk Premium Results

Description	Elec. RP	Gas RP
Projected Treasury Yield	10.00%	10.00%
3-Month Average Yields		
A-Rated Utility Bond	10.11%	10.05%
Baa-Rated Utility Bond	10.30%	10.24%
6-Month Average Yields		
A-Rated Utility Bond	10.03%	9.97%
Baa-Rated Utility Bond	10.22%	10.16%

J. Capital Asset Pricing Model

Q PLEASE DESCRIBE THE CAPM.

A The CAPM method of analysis is based upon the theory that the market-required ROR for a security is equal to the risk-free rate, plus a risk premium associated with the specific security. This relationship between risk and return can be expressed mathematically as follows:

$R_i = R_f + B_i \times (R_m - R_f)$ where:

R_i = Required return for stock i
R_f = Risk-free rate
R_m = Expected return for the market portfolio
B_i = Beta - Measure of the risk for stock

The term "beta" in the equation represents the stock-specific risk that cannot be reduced through diversification. In a well-diversified portfolio, specific risks related to individual stocks can be reduced by balancing the portfolio with securities that offset

the impact of firm-specific factors, such as business cycle, competition, product mix, and production limitations.

Non-diversifiable risks, on the other hand, are related to market conditions and are referred to as systematic risks. These risks cannot be reduced through diversification and are considered market risks. Conversely, non-systematic risks, also known as business risks, can be reduced through diversification.

According to the CAPM, the market does not compensate investors for taking on risks that can be diversified away. Thus, investors are only compensated for taking on systematic, or non-diversifiable, risks. Beta is a measure of these systematic risks.

Q PLEASE DESCRIBE THE INPUTS TO YOUR CAPM.

A The CAPM requires an estimate of the market risk-free rate, the stock's beta, and the Market Risk Premium ("MRP"). The MRP is the difference between the expected market return and the risk-free rate.

Q WHAT DID YOU USE AS AN ESTIMATE OF THE MARKET RISK-FREE RATE?

A As previously noted, *Blue Chip Financial Forecasts*' projected 30-year Treasury bond yield is 4.50%.[17] The current 30-year Treasury bond yield is 4.74%, as shown in Exhibit CCW-13 at page 1. I used *Blue Chip Financial Forecasts*' projected 30-year Treasury bond yield of 4.50% for my CAPM analysis.

[17] *Blue Chip Financial Forecast* June 2, 2025.

Q WHAT BETA DID YOU USE IN YOUR ANALYSIS?

A As shown in Exhibit CCW-14, the current proxy group average and median *Value Line* beta estimates are 0.84 and 0.80, respectively. In my experience, these beta estimates are abnormally high and are unlikely to be sustained over the long-term. As such, I have also reviewed the historical average of the proxy group's *Value Line* betas. The historical average *Value Line* beta since 2014 is 0.78 and has ranged from 0.56 to 0.94. Prior to the recent pandemic, the high end of this range was 0.75.

In addition to *Value Line*, I have also included adjusted beta estimates as provided by Market Intelligence's Beta Generator Model. This model relied on a five-year period on a weekly basis ending May 30, 2025. The average and median Market Intelligence betas are 0.46 and 0.46, respectively. Market Intelligence betas, as calculated using its Beta Generator Model, are adjusted using the Vasicek method and calculated using the S&P 500 as the proxy for the investable market. This is in stark contrast with the *Value Line* beta estimates that are adjusted using a constant weighting of 67%/35% to the raw beta/market beta and use the New York Stock Exchange ("NYSE") as the proxy for the investable market. Because I rely on the S&P 500 to estimate the expected return on the investable market, it makes sense to rely on beta estimates that are calculated using the S&P 500 as the benchmark for the market. Further, as S&P explains:

> The Vasicek Method is a superior alternative to the Bloomberg Beta adjustment. The Bloomberg adjustment is not appropriate for a vast number of situations, as it assigns constant weighting regardless of the standard error in the raw beta estimation (Bloomberg Beta = 1/3*market beta + 2/3*Raw Beta). Given the statistical fact that a larger sample size yields a smaller error, the Vasicek method more appropriately adjusts the raw beta via weights determined by the variance of the individual security versus the variance of a larger sample of comparable companies.

> The weights are designed to bring the raw beta closer to whichever beta estimation has the smallest error. This is a feature the Bloomberg beta cannot replicate.[18]

Notably, while S&P makes reference to the Bloomberg method of applying 2/3 and 1/3 weights to the raw beta and market beta, respectively, the comparison still applies to *Value Line's* methodology of applying 67% and 35% weights. Both methods are forms of the Blume adjustment.[19] While the weights are slightly different between the Bloomberg and *Value Line* methods, they are similar and apply a constant weight without any regard to accuracy. As such, S&P's criticisms apply to both Bloomberg betas and *Value Line* betas.

Because current beta estimates are based on the most recent five years of historical stock returns and volatility, they are being heavily impacted by the market fallout in early 2020 as the global pandemic set in and the market reacted, with this S&P 500 falling more than 40%. For this reason, it is not reasonable to assume current beta estimates, particularly Blume-adjusted betas such as those published by *Value Line*, are reflective of investor expectations at this time.

[18]S&P Market Intelligence, Beta Generator Model.

[19]The Blume adjustment is a tool used to refine a beta measurement in finance. In general, beta attempts to explain how much a particular investment's price moves compared to the overall market. But beta is often based on historical data, which may not be an accurate method for predicting the future. The Blume adjustment tries to address this by considering the idea that, in the long run, most investments tend to become more similar in their riskiness to the overall market (represented by a beta of 1).

Q IS THERE AN EXPLANATION FOR WHY THE VASICEK-ADJUSTED BETAS FROM S&P ARE SIGNIFICANTLY LOWER THAN THE *VALUE LINE* BETAS IN YOUR ANALYSIS?

A The Vasicek-adjusted betas, which average 0.46 for the proxy group, are significantly lower than the *Value Line* betas, which average 0.85, due to differences in how each method corrects for estimation error. The Vasicek method adjusts each company's raw beta toward a lower industry-specific mean when the underlying data is less reliable. This is especially relevant for utilities, which typically have stable earnings, limited volatility, and weaker correlations with overall market returns. As a result, the Vasicek method often pulls utility betas closer to a range of 0.4 to 0.6. In contrast, *Value Line's* method adjusts toward the broader market average of 1.0, which inflates the final estimate relative to Vasicek. In the current environment, utility stocks have exhibited particularly low volatility and reduced market sensitivity, making the Vasicek adjustment more pronounced. Both approaches use five years of weekly returns, but they differ in how they respond to the statistical quality of the input data. The lower Vasicek betas reflect utilities' defensive and low-risk investment profile more conservatively.

Q YOU MENTION THAT THE CURRENT 5-YEAR VALUE LINE BETA ESTIMATES MIGHT NOT BE REFLECTIVE OF INVESTOR EXPECTATIONS, AND POTENTIALLY OVERSTATE THE COST OF EQUITY. DO YOU HAVE EVIDENCE TO SUPPORT THAT HYPOTHESIS?

A Yes. As mentioned above, *Value Line's* beta estimates calculated over a 5-year historical price period will include the unprecedented volatility and market prices caused by the onset of the COVID-19 pandemic in early 2020. It is unreasonable to assume that those prices and resulting volatility resemble investor expectations going forward. Prior to the market fallout from the pandemic, utility beta estimates were at several year lows. Subsequent to the period of peak volatility from the pandemic, utility betas have actually declined back toward their normalized levels. This is demonstrated in Table CCW-9. In this table, I present the raw unadjusted beta estimates for *Value Line's* reported 5-year period as well as a 3-year period ending May 30, 2025. I then apply the Blume adjustment using the same weighting applied by *Value Line*.[20]

[20]The *Value Line* method to calculate adjusted betas is as follows: $B_{adjusted} = 0.35 + 0.67 \times B_{unadjusted.}$

Table CCW-9

Beta Comparison

Proxy Group	5-Year Value Line Beta[1]		3-Year Beta[3]	
	Unadjusted[2]	Reported	Unadjusted	Adjusted[4]
Atmos Energy Corporation	0.60	0.75	0.57	0.73
New Jersey Resources Corporation	0.75	0.85	0.52	0.70
NiSource Inc.	0.75	0.85	0.70	0.82
Northwest Natural Holding Company	0.67	0.80	0.59	0.74
ONE Gas, Inc.	0.67	0.80	0.56	0.72
Southwest Gas Holdings, Inc.	0.67	0.80	0.67	0.80
Spire Inc.	0.67	0.80	0.56	0.73
Alliant Energy Corporation	0.90	0.95	0.62	0.76
Ameren Corporation	0.82	0.90	0.55	0.72
American Electric Power Company, Inc.	0.75	0.85	0.43	0.64
Duke Energy Corporation	0.52	0.70	0.40	0.62
Edison International	0.82	0.90	0.76	0.86
Entergy Corporation	0.97	1.00	0.61	0.76
Evergy, Inc.	0.90	0.95	0.54	0.71
IDACORP, Inc.	0.60	0.75	0.45	0.65
NorthWestern Corporation	0.67	0.80	0.50	0.69
OGE Energy Corp.	1.04	1.05	0.67	0.80
Pinnacle West Capital Corporation	0.67	0.80	0.55	0.72
Portland General Electric Company	0.67	0.80	0.55	0.72
Southern Company	0.60	0.75	0.39	0.61
Xcel Energy Inc.	0.60	0.75	0.50	0.69
Average	0.73	0.84	0.56	0.72
Median	0.67	0.80	0.55	0.72

Source:

[1] *The Value Line Investment Survey* , March 7, April 18, May, 9, and May 23, 2025.

[2] Estimated the unadjusted beta by removing *Value Line* 's Blume adjustment methodology: (Unadjusted Beta - 0.35) / 0.67.

[3] S&P Global Market Intelligence, betas for the period 5/30/2022 - 5/30/2025.

[4] Adjusted using *Value Line* 's Blume adjustment methodology: 0.35+(0.67 x Unadjusted Beta).

This data clearly demonstrates that systematic market risk has subsided for regulated utilities after controlling for the impacts of the global pandemic with average and median beta estimates of 0.72 and 0.72, respectively.

Q HOW DID YOU DERIVE YOUR MRP ESTIMATES?

A My MRP estimates are derived using two general approaches: a risk premium approach and a DCF approach. I also consider the normalized MRP of 5.50% with the normalized risk-free rate of 4.77% as recommended by Kroll, formerly known as Duff & Phelps.[21] Based on this methodology and utilizing a "normalized" risk-free rate of 4.77%, Kroll concludes that the current expected, or forward-looking, MRP is 5.50%, implying an expected return on the market of 10.27%.[22]

Q PLEASE DESCRIBE YOUR MRP ESTIMATE DERIVED USING THE RISK PREMIUM METHODOLOGY.

A The forward-looking risk premium-based estimate was derived by estimating the expected return on the market (as represented by the S&P 500) and subtracting the risk-free rate from this estimate. I estimated the expected return on the S&P 500 by adding an expected inflation rate to the long-term historical arithmetic-average real return on the market. The real return on the market represents the achieved return above the rate of inflation.

Morningstar Direct calculates the historical arithmetic-average real-market return over the period 1926 to 2023 to be 9.02%.[23] A current consensus for projected inflation is 2.50%.[24] Using these estimates, the expected market return is 11.75%.[25]

[21]Kroll, and its predecessor Duff & Phelps, is a provider of economic, financial, and valuation data that is often relied on by finance professionals and cited in ROR testimony.

[22]Kroll, *Kroll Recommended U.S. Equity Risk Premium and Corresponding Risk-Free Rates to be Used in Computing Cost of Capital: January 2008 - Present* (Apr. 15, 2025). The current 20-year yield of 4.77% exceeds the "normalized" yield of 3.5%. In accordance with Kroll's prescribed method, the greater of the two shall be used under the normalized Kroll methodology, i.e., 4.77%.

[23]Morningstar Direct, data through 2023.

[24]Blue Chip Financial Forecast June 2, 2025.

[25][(1 + 9.02%) ∗ (1 + 2.50%) - 1] ∗ 100.

The MRP then is the difference between the 11.75% expected market return and the projected risk-free rate of 4.50%, or 7.20%.

Q PLEASE DESCRIBE YOUR MRP ESTIMATES DERIVED USING THE DCF METHODOLOGY.

A I employed two versions of the constant growth DCF model to develop estimates of the MRP. I first employed the Federal Energy Regulatory Commission's ("FERC") method of estimating the expected return on the market that was established in its Opinion No. 569-A. FERC's method for estimating the expected return on the market is to perform a constant growth DCF analysis on each of the dividend-paying companies of the S&P 500 index. The growth rate component is based on the average of the growth projections excluding companies with growth rates that were negative or greater than 20%.[26] The weighted average growth rate for the remaining companies is 10.40%. After reflecting the FERC prescribed method of adjusting the dividend yield by (1 + 0.5g), the weighted average expected dividend yield is 1.79%. Thus, the DCF-derived expected return on the market is the sum of those two components, or 12.19%. The MRP then is the expected market return of 12.19%, less the projected risk-free rate of 4.50%, or approximately 7.70%.

My second DCF-based MRP estimate was derived by performing the same DCF analysis described above, except I used all companies in the S&P 500 index rather than just the dividend-paying companies. The weighted average growth rate for these companies is 10.90%. After reflecting the FERC-prescribed method of adjusting the

[26]Opinion No. 569-A at page 210.

dividend yield by (1 + 0.5g), the weighted average expected dividend yield is 1.58%. Thus, the DCF-derived expected return on the market is the sum of those two components, or 12.48%. The MRP then is the expected market return of 12.48% less the projected risk-free rate of 4.50%, or approximately 8.00%.

The average expected market return based on the DCF model is 12.34% and the average MRP based on the two DCF estimates is 7.85%.

Q HOW DO YOUR EXPECTED MARKET RETURNS COMPARE TO CURRENT EXPECTATIONS OF FINANCIAL INSTITUTIONS?

A As shown in Table CCW-10, my average expected market return of 11.45%[27] exceeds long-term market expectations of several financial institutions.

[27] 11.45% = (10.27% + 12.34% + 11.75%) / 3.

TABLE CCW-10

Long-Term Expected Return on the Market

Source	Term	Expected Return Large Cap Equities
BlackRock Capital Management[1]	10 Years	6.70%
JP Morgan Chase[2]	10 - 15 Years	6.70%
Vanguard[3]	10 Years	2.8% - 4.8%
Research Affiliates[4]	10 Years	3.92%
Invesco[5]	10 Years	5.0% - 6.3%
Goldman Sachs[6]	10 Years	3.00%
Fidelity[7]	20 Years	5.70%
Schwab[8]	10 Years	6.00%

Sources:
[1]BlackRock Investment Institute, Capital market assumptions, May 22, 2025.
[2]JP Morgan Chase, Long-Term Capital Market Assumptions, 2025 Report.
[3]Vanguard economic and market outlook for 2025: Beyond the Landing.
[4]Research Affiliates, Asset Allocation Interactive. Retrieved 4/30/2025.
[5]2025 Invesco Capital Market Update.
[6]Goldman Sachs, Updating our long-term return forecast for US equities to incorporate the current high level of market concentration, October 18, 2024.
[7]Fidelity, Capital market assumptions
[8]Schwab's 2025 Long-Term Capital Market Expectations, January 3, 2025

When compared to the expected market returns of financial institutions above, my average expected market return of 11.45% is greater than all of them. For these reasons, my expected market returns, and the associated MRPs, should be considered reasonable, if not high-end estimates.

Q HOW DO YOUR ESTIMATED MRPS COMPARE TO THAT ESTIMATED BY KROLL?

A On its Cost of Capital portal, Kroll's MRP falls somewhere in the range of 5.50% to 7.17%. My MRP estimates are in the range of 5.50% to 7.85%.

Q HOW DOES KROLL MEASURE A MRP?

A Kroll's range is based on several methodologies. First, Kroll estimated a MRP of 7.17% based on the difference between the total market return on common stocks (S&P 500) less the income return on 20-year Treasury bond investments over the 1926-2023 period.[28]

Second, Kroll used the Ibbotson & Chen supply-side model which produced a MRP estimate of 6.22%.[29] Kroll explains that the historical MRP based on the S&P 500 was influenced by an abnormal expansion of P/E ratios relative to earnings and dividend growth. To control for the volatility of extraordinary events and their impacts on P/E ratios, Kroll takes into consideration the three-year average P/E ratio as the current P/E ratio. Therefore, Kroll adjusted this MRP estimate to normalize the growth in the P/E ratio to be more in line with the growth in dividends and earnings.

Finally, Kroll developed its own recommended equity, or MRP, by employing an analysis that takes into consideration a wide range of economic information, multiple risk premium estimation methodologies, and the current state of the economy by observing measures such as the level of stock indices and corporate spreads as indicators

[28]Kroll Cost of Capital Navigator.
[29]*Id.*

of perceived risk. Based on this methodology, and utilizing a "normalized" risk-free rate of 4.77%, Kroll concludes that the current expected, or forward-looking, MRP is 5.50%, implying an expected return on the market of 10.27%.[30]

Q WHAT ARE THE RESULTS OF YOUR CAPM ANALYSIS?

A As shown in Exhibit CCW-15, I have provided the results of twelve different applications of the CAPM. The first three results presented are based on the proxy group's current average *Value Line* beta of 0.84. The results of the CAPM based on these inputs range from 9.38% to 11.08%.

The next set of three results presented are based on the proxy group's historical *Value Line* beta of 0.78. The results of the CAPM based on these inputs range from 9.07% to 10.64%.

The third set of results presented are based on the proxy group's current *S&P Global Market Intelligence* beta of 0.46. The results of the CAPM based on these inputs range from 7.29% to 8.09%.

The final set of results presented are based on the proxy group's three-year beta estimate of 0.72. The results of the CAPM based on these inputs range from 8.74% to 10.17%.

My CAPM results are summarized in Table CCW-11.

[30]Kroll, *Kroll Increases U.S. Normalized Risk-Free Rate from 3.0% to 3.5%, but Spot 20-Year U.S. Treasury Yield Preferred When Higher* (Jun. 16, 2022).

Table CCW-11

CAPM Results Summary

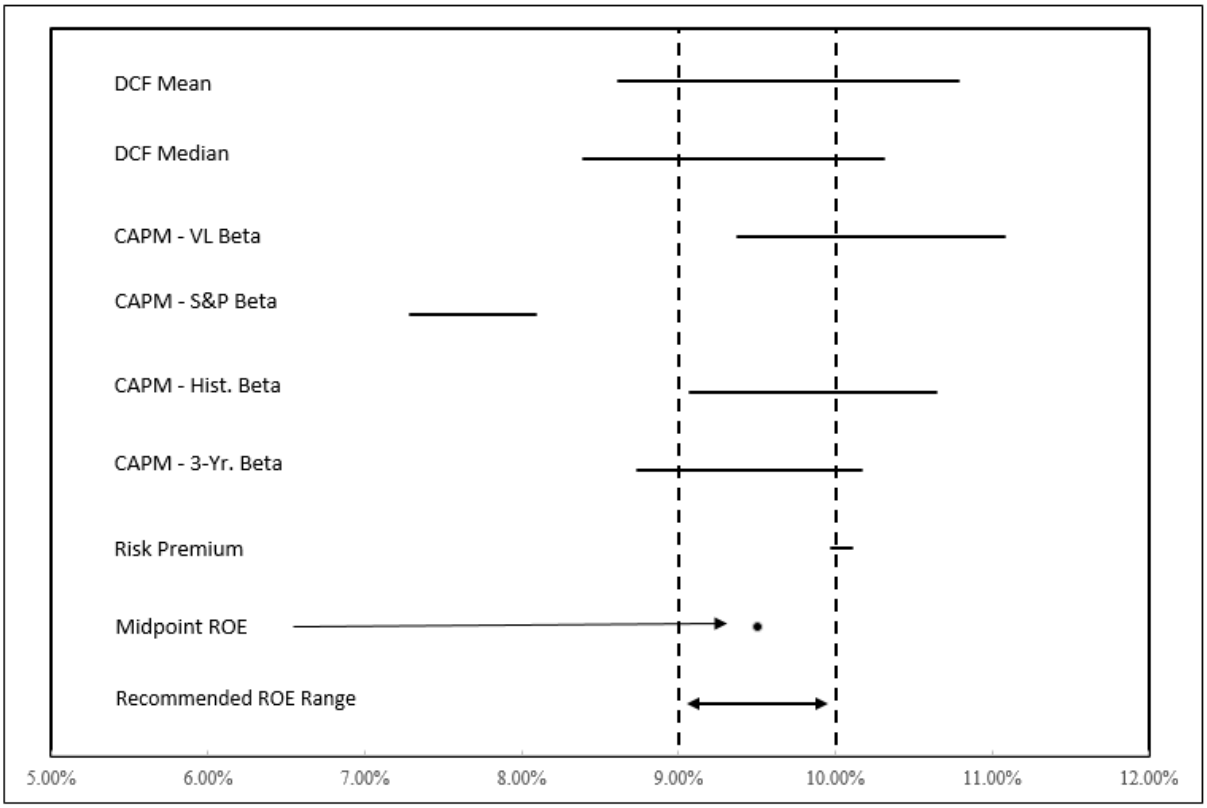
Description	Current VL Beta	Historical VL Beta	Current S&P Beta	3-Year Beta
Kroll Method	9.38%	9.07%	7.29%	8.74%
RP Method	10.53%	10.13%	7.80%	9.70%
FERC DCF Method	11.08%	10.64%	8.09%	10.17%
Average	**10.33%**	**9.95%**	**7.73%**	**9.54%**

K. Return on Equity Summary

Q BASED ON THE RESULTS OF YOUR RETURN ON COMMON EQUITY ANALYSIS DESCRIBED ABOVE, WHAT RETURN ON COMMON EQUITY DO YOU RECOMMEND FOR THE COMPANIES?

A The results of my analyses are summarized in Figure CCW-5. In this figure, I present the various measures of central tendency (i.e., the mean and median results) for each of my analytical models.

Figure CCW-5



Based on my analyses of the various methodologies described above, I estimate the Companies' current market ROE to be in the reasonable range of 9.00% to 10.00%. My recommended range accounts for the unsustainable growth rates assumed in the constant growth DCF model and the irrational assumption that *Value Line's* current beta estimates are reflective of current investor expectations. As described above, the results of the constant growth DCF using analysts' growth rates assume an average long-term growth rate of 6.87%, which is approximately 68% higher than the long-term projected GDP growth rate of 4.09%. This is an unsustainable assumption, and likely leads to an overstatement in the cost of equity for a low risk regulated utility. As such, it is my opinion that primary weight should be given to the sustainable growth and multi-stage models of the DCF. Based on my assessment of the Companies' overall risk profile and

the results of these analytical methods, I would recommend that this Commission authorize the Companies a ROE of 9.50%, which is the midpoint of my recommended range produced by these models.

IV. RESPONSE TO THE COMPANIES' WITNESS D'ASCENDIS

A. Summary of Direct

Q PLEASE DESCRIBE THE COMPANIES' WITNESSES ON THIS SUBJECT MATTER.

A Based on a revised submission of written direct, Witness Dylan D'Ascendis, in Revised Statement No. 2, provides written Direct Testimony on behalf of the Companies addressing the appropriate ROE for each Company. Witness Ryan M. Kucan, in Statement No. 2A, provides written Direct Testimony on behalf of the Companies addressing the ratemaking capital structure and cost of long-term debt for each Company. As noted above, I am not taking issue with the proposed ratemaking capital structure or cost of long-term debt proposed by Witness Kucan. However, the remainder of my testimony will address Mr. D'Ascendis' testimony, in which he recommends the Companies be authorized an ROE of 11.65%, which is the average of his analytical results adjusted for flotation costs. I demonstrate below that his ROE recommendation is excessive and should be rejected.

Q WHAT RETURN ON COMMON EQUITY IS WITNESS D'ASCENDIS PROPOSING FOR THIS PROCEEDING?

A Witness D'Ascendis estimates a market ROE in the range of 10.12% to 10.95% based on the results of various financial models applied to their proxy group of seven natural gas utility companies and 15 electric utility companies. Specifically, Witness D'Ascendis relies on the results of a DCF model, a traditional CAPM, an Empirical CAPM ("ECAPM"), and a Risk Premium method. In addition, Mr. D'Ascendis performs these financial models to two additional groups of non-price regulated companies. Importantly, the results of the models as applied to the non-price regulated companies establishes the top end of his ranges.

After adjusting the ROE for the Companies' relative size of 1.00% for Valley and 0.85% for Wellsboro and Citizens, and a performance adder up to 0.05% for the Companies, Witness D'Ascendis' adjusted range is 11.22% to 12.97%. Witness D'Ascendis recommends that the Companies be awarded an ROE of 11.65%.[31] The results of Witness D'Ascendis (Statement No. 2) recommendations are summarized in Table CCW-12.

[31] Joint Statement No. 2 at 5.

TABLE CCW-12

Summary of Results for Witnesses Kucan and D'Ascendis

Description	Gas & Electric Combined Results
DCF	10.29% - 10.32%
Risk Premium Model	10.79% - 10.86%
CAPM	10.75% - 11.12%
Non-Utility Range	11.84% - 11.92%
Unadjusted ROE Range	10.29% - 11.92%
Size Risk Adjustment	0.85% - 1.00%
Performance Adder	0.05%
Adjusted Recommended ROE Range	**11.22% - 12.97%**
Recommended ROE	**11.65%**

Q IS THE RECOMMENDED ROE OF THE COMPANIES' WITNESS D'ASCENDIS REASONABLE?

A No. For the reasons outlined below, several flaws and assumptions used by Witness D'Ascendis have led to a significant overstatement in the Companies' cost of equity and demonstrate that my recommended ROE of 9.50% is within the range of reasonable outcomes. As such, Witness D'Ascendis' recommendations should be rejected.

B. Witness D'Ascendis' DCF Analysis

Q PLEASE DESCRIBE THE WITNESS D'ASCENDIS' DCF ANALYSIS.

A The Companies' Witness performed a traditional constant growth DCF analyses on their proxy groups. He relied on analysts' earnings growth rate projections from S&P Capital IQ, *Value Line*, and Zack's. The average growth rate for their Gas Group is 6.48%. After he removes the results of Portland General Electric Company and TXNM Energy, the average growth rate for their Electric Group is 6.43%. Witness D'Ascendis used an annualized dividend and the closing stock prices as of February 28, 2025, to calculate each proxy company's dividend yield. His DCF for the Gas Group is 10.29%. After removing the DCF results of Portland General Electric Company and TXNM Energy for being more than two standard deviations from the Electric Group's mean, DCF results are 10.32%.

Q DO YOU HAVE ANY CONCERNS WITH THE WITNESS' DCF RETURN ESTIMATES?

A Yes. The Companies' Witness' DCF model is based entirely on analysts' projected growth. His proxy group's average DCF return is based on growth rates of 6.48% (Gas Group) and 6.43% (Electric Group). These growth rates are nearly 60% higher than the consensus economists' long-term projected growth rate of 4.09% for the economy described above. In other words, the Companies' Witness thinks it is reasonable for the proxy group to grow, on average, at a rate of 1.6x that of the economy. As explained above, it is unrealistic to expect utilities to maintain a growth rate that is well in excess of the anticipated growth in GDP. Accordingly, relying solely on a Constant Growth

DCF tends to overstate the DCF result. The Companies' Witness should have considered the results of a multi-stage DCF analysis as I have done. Had the Companies' Witness included a multi-stage DCF analysis, the low-end of their range would be consistent with mine near 9.0%.

C. Witness D'Ascendis' Risk Premium Model Analysis

Q PLEASE DESCRIBE THE COMPANIES' WITNESS' RISK PREMIUM ANALYSIS.

A The Companies' Witness estimated a risk premium return of 10.86% based on the results for the Gas Group and 10.79% for their Electric Group.[32] For the Gas Group, his Risk Premium results are derived using estimates of the equity risk premium based on the adjusted total market approach (5.68%/5.25%), the holding period return approach (4.76%) and the regression-derived Predicted Equity Risk Premium approach (4.73%/4.77%).[33] The average of his three equity risk premiums is 5.15%.[34] Adding his average equity risk premium of 5.15% to their estimate of the adjusted prospective proxy group bond yield (5.49%) produces a Risk Premium result of 10.64%.[35]

Q DO YOU HAVE ANY CONCERNS WITH THE COMPANIES' WITNESS' RISK PREMIUM METHODOLOGY?

A Yes, I do. First, it must be noted that even their lowest Risk Premium model result, after averaging together 16 different estimates of the equity risk premium, of 10.79%, is

[32] Joint Statement No. 2, at Schedule DWD-4.
[33] *Id.*, at Schedule DWD-4 at page 5.
[34] *Ibid.*
[35] *Id.*, at Schedule DWD-4, page 1.

higher than the highest authorized ROE for an electric distribution utility since at least 2012.[36] This clearly speaks to the unreasonableness of Mr. D'Ascendis' approach.

Second, Mr. D'Ascendis prepared his own estimate of what a projected yield will be for A2 rated utility bonds. This is not a consensus estimate or forecast made by market participants, but rather a yield of his own derivation. There is no evidence the market is relying on Mr. D'Ascendis' method of projecting yields for utility bonds. This is particularly concerning that he takes an average yield spread of utility bond yields over Aaa-rated corporate bonds based on a recent three-month average and assumed that relationship will hold true up to 10 years into the future as he relies on forecasted Aaa-rated corporate bond yields through 2035.

Third, the results of Mr. D'Ascendis' equity Risk Premium analysis are based on a total of 16 measurements of the equity risk premium between gas and electric. Those 16 equity risk premiums range from 4.16% (historical equity risk premium based on S&P's public utility index returns over utility bond yields) to 7.81% (beta-adjusted Equity Risk Premium Based on Bloomberg, *Value Line*, and S&P Global Market Intelligence S&P 500 Companies).[37] When looking at what the individual equity risk premium estimates are before they are mitigated by an averaging approach, his Risk Premium method would produce a cost of equity estimate as high as 13.61% for their Gas Group. That is clearly an outlier result and should not be relied upon.

[36]Based on my review of authorized ROEs tracked by Regulatory Research Associates, a division of S&P Global.

[37]7.81% = 0.79 x 9.88% from Schedule DWD-7, page 7. Schedule DWD-7, page 7.

Finally, Mr. D'Ascendis' use of the Predictive Risk Premium ("PRPM") approach is not widely used or frequently accepted by regulators in establishing the cost of equity.

D. Witness D'Ascendis' CAPM Analysis

Q HOW DID THE COMPANIES' WITNESS DERIVE HIS CAPM RETURN ESTIMATE FOR THE COMPANIES?

A The Companies' Witness developed his CAPM return estimate on their Schedule DWD-5. As shown on that schedule, he relied on a Gas Group beta of 0.79 and an Electric Group beta of 0.73, which was the average of the mean and median betas published by Bloomberg and *Value Line* for their proxy companies, an average MRP of 8.15% and a projected risk-free rate of 4.55%. These inputs produce a traditional CAPM return estimate of 10.96% (Gas Group) and 10.47% (Electric Group).

Q DO YOU HAVE ANY INITIAL COMMENTS CONCERNING THE COMPANIES' WITNESS' CAPM?

A Yes, I do. The CAPM results are based, in part, on *Value Line* beta estimates that are excessive. For example, Mr. D'Ascendis' Gas Group's average *Value Line* beta at the time of his study was 0.92. Currently, as of the most recently published reports from May 23, 2025, his Gas Group betas have declined to an average of 0.81. Notably, all seven gas companies in the Gas Group experienced a meaningful decline in their *Value Line* beta. Simply updating Mr. D'Ascendis' *Value Line* betas will reduce the Gas Group's traditional CAPM by approximately 45 basis points.

Q DO YOU HAVE ANY ISSUES WITH THE COMPANIES' WITNESS' CAPM STUDY?

A Yes, I do. I have concerns with certain of his MRP estimates used to calculate their average MRP. Specifically, his third and fifth MRP.

Q PLEASE DESCRIBE THE COMPANIES' WITNESS' ESTIMATED MRPS, GENERALLY.

A Witness D'Ascendis averages five MRP estimates to develop his recommended MRP of 8.15%.

His first MRP estimate is based on historical Ibbotson data. With this methodology, he estimates a MRP of 7.31%. His second MRP is based on a regression analysis and produced a risk premium of 7.94%. Mr. D'Ascendis' third MRP is based on the application of the PRPM applied to historical market returns data which produced a MRP of 818%. His fourth method is based on *Value Line's* 3-5 year projected market return of 11.20% less their risk-free rate of 4.55% to derive an expected MRP on the *Value Line* index of 6.65%. Mr. D'Ascendis' fifth MRP is based on a projected return on the S&P 500 of 15.23%, which produced a risk premium of 10.68% after their risk-free rate is subtracted. The average of these five MRPs is 8.15%.[38]

Q PLEASE COMMENT ON THE COMPANIES' WITNESS' MRP ESTIMATES.

A As an initial matter, Mr. D'Ascendis' average MRP of 8.15% is slightly above the high-end of the range 5.00% to 8.00% that is indicated by empirical evidence. I will

[38]Schedule DWD-5, page 2.

note that I agree with certain of their MRP estimates. It is the estimates that fall outside of the range suggested by the empirical evidence that are a cause for concern.

In particular, Mr. D'Ascendis' third MRP of 8.18% based on the PRPM model and his fifth MRP (10.68%) based on a projected return on the market of 15.23% are excessive. These MRP estimates exceed the high end of the empirical evidence by as much as 33.5%. For example, Dr. Morin notes in his book, Modern Regulatory Finance, that several studies of the MRP have concluded that a MRP in the range of 5.0% to 8.0% is a reasonable estimate for the United States.[39] For example, the Duarte and Rosa study that Dr. Morin cites concludes that the historical mean is "quite difficult to improve upon when considering out-of-sample performance measures."[40] Dr. Morin also notes that a survey of professional practices showed that 71% of textbooks/tradebooks used a historical average as the MRP, and 60% of financial advisors used a MRP in the range of 7.0% to 7.4% (similar to a long-term arithmetic average MRP).[41]

For these reasons, the Companies' Witness' traditional CAPM results are excessive and unreliable. Simply removing the most excessive MRP of 10.68% would reduce their average MRP from 8.15% to 7.52%, a reduction of 63 basis points. If we also remove the other MRP of 8.18% that falls outside the empirical range, the average MRP would be reduced to 7.30%, an 85-basis point reduction. Updating Mr. D'Ascendis' CAPM with a more recent average of his beta of 0.73 described above and the adjusted average MRP of 7.30% with his risk-free rate of 4.55% indicates a

[39]Dr. Morin references studies by Duarte & Rosa; Professors Ross, Westerfield, and Jordan; Mahera; and Brealey, Myers, and Allen. See *Modern Regulatory Finance,* Dr. Roger A. Morin, at 190-192. Dr. Morin notes in his textbook that there is a "slight preference" for the upper end of the range (i.e., 8%) during tumultuous times in capital markets with examples being the 2008-2009 credit crisis and the 2020 pandemic.

[40]*See Modern Regulatory Finance,* Dr. Roger A. Morin, at 191, citing the Duarte and Rosa study.

[41]See *Modern Regulatory Finance,* Dr. Roger Morin, at 190, footnote 35.

traditional CAPM ROE of 9.91%, a 105-basis point reduction to his Gas Group's CAPM.

E. Witness D'Ascendis' ECAPM Analysis

Q PLEASE DESCRIBE THE COMPANIES' WITNESS' ECAPM ANALYSIS.

A The Companies' Witness applies the same beta, MRP and risk-free rate that he used in his CAPM for his ECAPM. The ECAPM analysis modifies the traditional CAPM equation by including a risk premium weighted by the utility beta, and the overall market beta of 1.0. The original ECAPM analysis was designed to use raw, or unadjusted, regression betas. In the Companies' Witness' ECAPM analysis, he adds two weighted risk premiums to a risk-free rate: a 75% weighted risk premium based on a 0.76 utility beta, and a 25% weighted risk premium based on a beta equal to the overall market beta of 1.0. The theory of the ECAPM is that a beta of less than 1.0 will increase toward the market beta of 1.0 over time, which is necessary because the risk of securities will be increasing over time. The ECAPM formula employed by Mr. D'Ascendis is as follows:

$$R_i = R_f + [(.75) \times B_i \times (R_m - R_f)] + [(.25) \times B_m \times (R_m - R_f)] \text{ where:}$$

R_i = Required return for stock i
R_f = Risk-free rate
R_m = Expected return for the market portfolio
B_i = Beta coefficient for the stock (0.95)
B_m = Beta coefficient for the market (1.0)

Q WHAT ISSUES DO YOU TAKE WITH THE COMPANIES' WITNESS' ECAPM ANALYSIS?

A The biggest issue I have with Mr. D'Ascendis' ECAPM analysis is his use of an adjusted beta as published by *Value Line*. The impact of his ECAPM adjustment is to increase his beta estimate from 0.79 to 0.843.[42] The weighting adjustments applied in the ECAPM are mathematically consistent with the adjustments made to create the *Value Line* adjusted betas since the inputs are all multiplicative as shown in the formula above.

Mr. D'Ascendis' reliance on an adjusted *Value Line* beta in his ECAPM study is inconsistent with the academic research that I am aware of supporting the development of the ECAPM.[43] The *Value Line* adjusted betas are already adjusted for a stock's long-term tendency to converge to 1.00. Importantly, the timing of that convergence is not known, and therefore, a constant weighting is applied when adjusting raw betas using the Blume method, as done by *Value Line* and Bloomberg. Thus, the end result of using the *Value Line* adjusted betas in the ECAPM is essentially an expected return line that has been flattened by two duplicative adjustments. In other words, the vertical intercept has been raised twice and the security market line has been flattened twice: once through the adjustments *Value Line* made to the raw beta, and again by weighting the risk-adjusted MRP as Mr. D'Ascendis has done.

Moreover, he further increases the intercept and flattens the security market line by using projected long-term Treasury yields that are at odds with current market

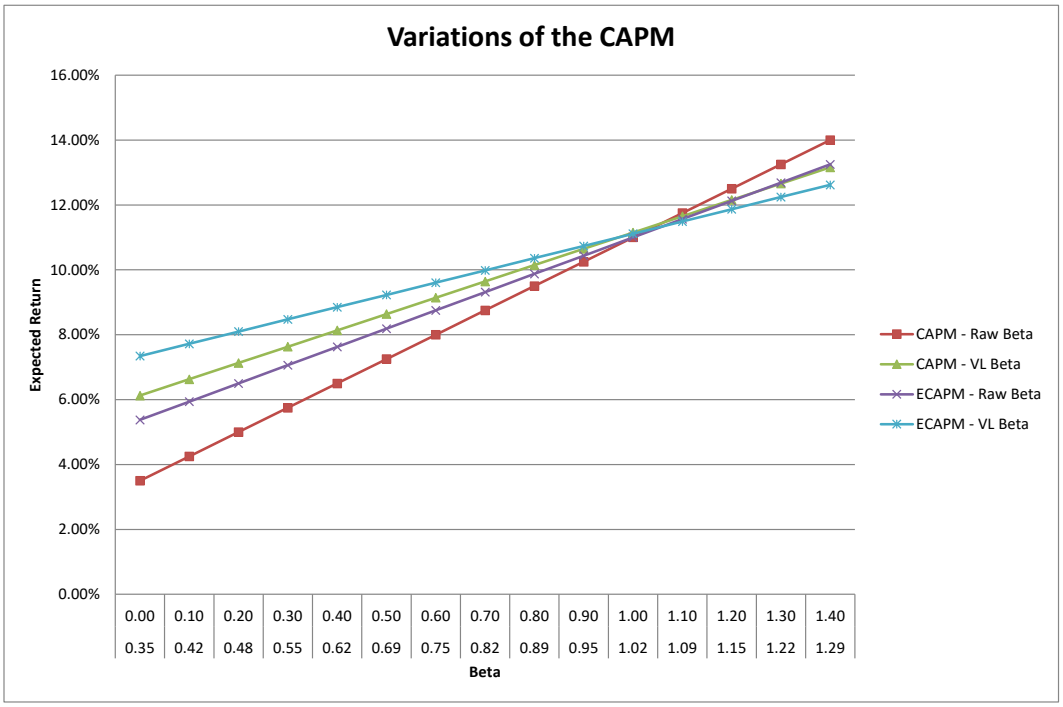
[42] 75% x 0.79 + 25% x 1 = 0.843.

[43] *See* Black, Fischer, "Beta and Return," *The Journal of Portfolio Management,* Fall 1993, 8-18; and Black, Fischer, Michael C. Jensen and Myron Scholes, "The Capital Asset Pricing Model: Some Empirical Tests," 1972.

expectations and inconsistent with the Federal Reserve's projections and monetary policy.

The ECAPM will raise the intercept point of the security market line and flatten the slope. Again, this has the effect of increasing CAPM return estimates for companies with betas less than 1, and decreasing the CAPM return estimates for companies with betas greater than 1. I have modeled the expected return line resulting from the application of the various forms of the CAPM/ECAPM below in Figure CCW-6.

FIGURE CCW-6



Along the horizontal axis in Figure CCW-6, I have provided the raw unadjusted beta (top row) and the corresponding adjusted *Value Line* beta (bottom row). As shown in Figure CCW-6, the CAPM using a *Value Line* beta compared to the CAPM using an unadjusted beta shows that the *Value Line* beta raises the intercept point and flattens the slope of the security market line. As shown in the figure above, the two variations with the most similar slope are the CAPM with the *Value Line* beta, and the ECAPM with a

raw beta. This evidence shows that the ECAPM adjustment has a very similar impact on the expected return line as a *Value Line* adjusted beta. Another observation that can be made from the figure above is the magnifying effect that the ECAPM using a *Value Line* adjusted beta has on raising the vertical intercept and flattening the slope relative to all other variations. There is simply no legitimate basis to use an adjusted beta within an ECAPM because it unjustifiably alters the security market line and materially inflates a CAPM return for a company with a beta less than 1.

F. Witness D'Ascendis' Non-Price Regulated Proxy Group Analysis

Q PLEASE DESCRIBE THE ANALYSIS DONE BY THE COMPANIES' WITNESS ON THEIR NON-PRICE REGULATED PROXY GROUPS.

A The Companies' Witness performed the same financial models described above to two groups of non-price regulated companies. One group consisted of 47 companies, while the other group consisted of 49 companies.

The indicated ROE produced by Mr. D'Ascendis' analysis applied to his proxy group of non-price regulated companies is 11.84% to 11.92%.

Q IS THE COMPANIES' WITNESS' ADDITIONAL ANALYSES REASONABLE?

A No. The Companies' Witness' use of non-price regulated companies to estimate the Companies' cost of equity is fundamentally unreasonable because it relies on companies that operate in speculative, highly competitive, and profit-maximizing sectors of the economy. These companies are not subject to the same regulatory oversight, earnings

constraints, or obligations to serve as Valley, a regulated natural gas distribution utility, or as Wellsboro and Citizens, regulated electric distribution companies.

By referencing non-price regulated companies, the Companies' Witness introduces a systematic upward bias into their ROE estimate, improperly inflating the return level that is appropriate for a stable, regulated utility. The risk profiles of these companies, many of which pursue aggressive growth strategies or operate in sectors subject to economic and technological disruption, bear no resemblance to the lower-risk, asset-intensive, and heavily regulated environment in which the Companies operate.

Ultimately, the Companies' Witness' analysis leads to an overstated and unjustified cost of equity estimate that is inconsistent with the standards requiring that rates be "just and reasonable" for both customers and investors.

G. Witness D'Ascendis' Proposed Performance Adder

Q PLEASE DESCRIBE THE PERFORMANCE ADDER PROPOSED BY THE COMPANIES' WITNESS.

A The Companies' Witness wants to reward shareholders and burden ratepayers by increasing the allowed ROE by 0.05%, or 5 basis points.

The Companies' Witness' subjective decision to add a 5-basis point management adder is entirely based on the testimony of Valley's Witness Mr. Rogers, Citizens' Witness Mr. Johnson, and Wellsboro's Witness Farnsworth.[44]

[44]Joint Statement No. 2 at 51-52.

As described above, the *Hope and Bluefield Standards* conclude that the utility has "no constitutional rights to profits"[45] and defined the ratepayer/investor balance as follows:

> The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties.[46]

As such, a fair ROR is based on the expectation that the utility's costs reflect efficient and economical management, and the return will support its credit standing and access to capital, but the return will not be in excess of this level. Mr. D'Ascendis' proposal to further reward shareholders for its "exemplary performance" is counter to the *Hope and Bluefield Standards* as such standards are assumed the Company will operate under efficient and economical management. Adding an additional 5 basis points to an ROE that would be the highest ROE allowed for a gas utility in the lower 48 United States since at least 2012 is egregious and should be rejected.

In addition, I am unaware of any financial literature or textbooks that suggest a Company's cost of equity includes a premium to compensate shareholders for exemplary management performance.

[45] *Bluefield,* 262 U.S. at 692-93.
[46] *Id*. at 693 (Emphasis Added).

Q DID THE COMPANIES' WITNESS PERFORM AN INDEPENDENT ASSESSMENT OF WHAT THE PERFORMANCE ADDER SHOULD BE, IF ANY?

A No. He does not. Again, he relies entirely on the testimony of the Companies' implicitly biased, highest ranking member of management of each Valley, Citizens, and Wellsboro.[47]

H. Witness D'Ascendis' Proposed Size Adjustment

Q PLEASE DESCRIBE THE SIZE ADJUSTMENT PROPOSED BY THE COMPANIES' WITNESS.

A Mr. D'Ascendis proposes to add a ROE adder of 0.85% (85 basis points) for Citizens and Wellsboro, and 1.00% (100 basis points) for Valley, to reflect his belief that the Companies have greater risk relative to that of their proxy group companies due to the relative size of the Companies.[48]

Q HOW DID THE COMPANIES' WITNESS ESTIMATE THIS SIZE ADJUSTMENT?

A Mr. D'Ascendis approximates a market value for the Companies (the Companies are not publicly traded and do not have a market value) and compares this market size to the actual market capitalization size for their utility proxy groups. He estimates the Companies' market capitalization by applying the proxy group's average market-to-book ratio of 1.62x (Gas) to 2.01x (Electric) to the book value of the

[47] Joint Statement No. 2 at 51-52.
[48] Joint Statement No. 2 at 51.

Companies' equity. Mr. D'Ascendis estimates that the utility proxy group market valuation is between 253.8x to 913.2x larger than their estimated market value for the Companies.

He then compares the actual market capitalization size for the proxy groups, and his estimates of market value for the Companies, to the market capitalization size deciles published by Kroll. He relies on Kroll's estimated CAPM return difference for companies that fall within market capitalization size deciles. The Companies' Witness estimates that the proxy group market capitalization size puts them in the 3rd (Electric Group) and 5th (Gas Group) deciles of returns as estimated by Kroll, and his estimates of market capitalization for the Companies puts it in the 10th decile size return category. The difference between the 3rd decile and the 10th decile indicates a ROE adder of around 3.98%, to reflect the difference in risk caused by market capitalization size. While the spread from the 10th decile to the 5th indicates a ROE adder of around 3.73%. However, using his judgment, Witness D'Ascendis recommends a ROE size adder of 0.85% for Citizens and Wellsboro and 1.00% for Valley.[49]

Q IS THE COMPANIES' WITNESS' PROPOSED SIZE ADJUSTMENT FOR THE COMPANIES REASONABLE?

A No. There are several fundamental errors and flaws in Mr. D'Ascendis' quantitative estimate and logic. First and foremost, the Companies are not a publicly traded companies. For this reason, Mr. D'Ascendis does not know what the market value capitalization is for the Companies. His approximation simply is not meaningful and

[49] *Id.*

cannot be used to make an accurate measurement of a ROE adder if one is so justified, which it is not.

Second, Mr. D'Ascendis has not demonstrated that size premiums are applicable to the utility industry. For example, the average unadjusted betas for the 3rd, 5th, and 10th deciles in the Kroll risk premium study are 1.10, 1.17, and 1.38. These unadjusted betas are significantly higher than Mr. D'Ascendis' proxy group adjusted betas. In addition, there is empirical evidence which concludes that, while size premiums are present in industrial companies, such a size premium is not present in utility companies, nor are they appropriate to include in valuing utilities.[50]

Finally, modern portfolio theory operates under the assumption that the market does not compensate investors for taking on risks that can be diversified away. Thus, investors are only compensated for taking on systematic, or non-diversifiable market risks. The size adjustment as proposed by the Companies' Witness is not appropriate and should be denied.

Q DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A Yes, it does.

[50]Wong, Annie, 1993, Utility stocks and the size effect: An empirical analysis, Journal of the Midwest Finance Association, at 95-101.

QUALIFICATIONS OF CHRISTOPHER C. WALTERS

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Christopher C. Walters. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q PLEASE STATE YOUR OCCUPATION.

A I am a consultant in the field of public utility regulation and a Principal with the firm of Brubaker & Associates, Inc. ("BAI"), energy, economic and regulatory consultants.

Q PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EMPLOYMENT EXPERIENCE.

A I received a Bachelor of Science Degree in Business Economics and Finance from Southern Illinois University Edwardsville. I have also received a Master of Business Administration Degree from Lindenwood University.

As a Principal at BAI, I perform detailed technical analyses and research to support regulatory projects including expert testimony covering various regulatory issues. Since my career at BAI began in 2011, I have held the positions of Analyst, Associate Consultant, Consultant, Senior Consultant, and Associate. Throughout my tenure, I have been involved with several regulated projects for electric, natural gas and water and wastewater utilities, as well as competitive procurement of electric power and gas supply. My regulatory project work includes estimating the cost of equity capital, capital structure evaluations, assessing financial integrity, merger and acquisition

related issues, risk management related issues, depreciation rate studies, and other revenue requirement issues.

BAI was formed in April 1995. BAI and its predecessor firm have participated in more than 700 regulatory proceedings in 40 states and Canada.

BAI provides consulting services in the economic, technical, accounting, and financial aspects of public utility rates and in the acquisition of utility and energy services through RFPs and negotiations, in both regulated and unregulated markets. Our clients include large industrial and institutional customers, some utilities and, on occasion, state regulatory agencies. We also prepare special studies and reports, forecasts, surveys and siting studies, and present seminars on utility-related issues.

In general, we are engaged in energy and regulatory consulting, economic analysis and contract negotiation. In addition to our main office in St. Louis, the firm also has branch offices in Corpus Christi, Texas; Louisville, Kentucky and Phoenix, Arizona.

Q HAVE YOU EVER TESTIFIED BEFORE A REGULATORY BODY?

A Yes. I have sponsored testimony before state regulatory commissions including: Arizona, Arkansas, Colorado, Delaware, Florida, Georgia, Illinois, Iowa, Kansas, Kentucky, Louisiana, Maryland, Massachusetts, Michigan, Minnesota, Missouri, Montana, Nevada, New Mexico, North Carolina, Ohio, Oklahoma, Oregon, South Carolina, Texas, Utah, and Wyoming. In addition, I have also sponsored testimony before the City Council of New Orleans and an affidavit before the FERC.

Q PLEASE DESCRIBE ANY PROFESSIONAL REGISTRATIONS OR ORGANIZATIONS TO WHICH YOU BELONG.

A I earned the Chartered Financial Analyst ("CFA") designation from the CFA Institute. The CFA charter was awarded after successfully completing three examinations which covered the subject areas of financial accounting and reporting analysis, corporate finance, economics, fixed income and equity valuation, derivatives, alternative investments, risk management, and professional and ethical conduct. I am a member of the CFA Institute and the CFA Society of St. Louis.

533406

Valley Energy, Inc. / Citizens' Electric Company of Lewisburg, PA / Wellsboro Electric Company

Electric Utilities
(Valuation Metrics)

Line	Company	Price to Earnings (P/E) Ratio [1] 23-Year Average (1)	2024 [2] (2)	2023 (3)	2022 (4)	2021 (5)	2020 (6)	3-Year Averages 2017-2019 (7)	2014-2016 (8)	2011-2013 (9)	2008-2010 (10)	2005-2007 (11)	2002-2004 (12)
1	ALLETE	18.24	18.80	16.80	18.10	20.60	18.30	23.30	16.97	16.40	15.33	16.42	25.21
2	Alliant Energy	17.11	20.10	16.40	21.40	21.20	21.20	20.30	19.00	14.77	13.27	14.84	15.54
3	Ameren Corp.	16.89	20.30	15.50	21.50	21.40	22.20	20.33	17.50	13.93	11.07	17.83	15.19
4	American Electric Power	15.35	18.40	15.90	21.10	17.10	19.60	19.57	15.63	13.40	12.17	14.30	11.92
5	Avangrid, Inc.	23.69	N/A	16.30	19.60	23.20	23.60	25.50	27.00	N/A	N/A	N/A	N/A
6	Avista Corp.	18.23	16.20	14.60	20.00	20.20	21.20	20.97	17.90	16.00	13.03	21.91	19.18
7	Black Hills	17.45	13.90	14.20	18.10	17.70	17.00	19.17	19.13	22.13	14.00	16.01	15.20
8	CenterPoint Energy	17.00	19.80	20.40	18.70	26.10	15.90	24.80	19.00	16.03	12.30	14.77	9.83
9	CMS Energy Corp.	18.44	20.50	18.60	22.90	23.60	23.30	21.97	18.83	15.00	12.33	20.53	12.39
10	Consol. Edison	16.27	19.70	17.70	20.30	17.20	19.00	18.87	16.77	15.07	12.70	14.80	15.26
11	Dominion Resources	18.23	15.80	18.30	18.70	19.50	22.60	19.30	22.13	18.47	13.60	20.49	14.12
12	DTE Energy	16.81	18.90	16.90	22.40	30.00	16.30	18.63	17.33	15.43	12.50	16.51	13.67
13	Duke Energy	17.29	19.00	16.50	19.60	18.90	17.10	18.20	19.13	16.23	14.43	16.10	N/A
14	Edison Int'l	16.75	9.70	14.30	40.60	29.70	34.90	16.95	15.23	11.40	10.80	13.58	17.45
15	El Paso Electric	17.68	N/A	N/A	N/A	N/A	N/A	24.32	17.79	14.32	11.14	19.63	21.10
16	Entergy Corp.	14.93	25.80	20.60	21.10	15.00	15.30	15.10	12.10	11.17	13.40	16.62	13.46
17	Eversource Energy	18.01	12.40	13.10	20.90	22.20	23.70	20.10	18.23	17.40	13.03	21.84	16.73
18	Evergy, Inc.	19.20	17.30	14.80	19.90	16.20	21.70	22.25	N/A	N/A	N/A	N/A	N/A
19	Exelon Corp.	14.52	17.50	15.40	19.90	16.60	12.40	13.80	13.70	14.60	13.50	16.70	11.74
20	FirstEnergy Corp.	15.26	16.80	14.40	17.00	14.10	15.70	14.03	12.83	18.87	13.43	15.30	16.52
21	Fortis Inc.	19.24	18.80	17.00	21.10	21.20	20.60	17.70	21.30	19.63	17.37	19.39	N/A
22	Great Plains Energy	15.52	N/A	N/A	N/A	N/A	N/A	N/A	17.94	15.28	16.23	16.20	11.97
23	Hawaiian Elec.	17.36	11.20	6.00	18.50	18.20	21.50	20.30	16.63	16.37	20.53	19.30	15.47
24	Hydro One Limited[3]	18.66	25.20	20.50	19.60	18.70	9.20	19.25	18.10	N/A	N/A	N/A	N/A
25	IDACORP, Inc.	17.25	19.60	18.10	21.00	20.80	19.90	21.13	16.67	12.43	11.97	16.66	20.29
26	MGE Energy	20.35	26.00	21.10	24.70	25.50	26.40	27.63	20.80	16.67	14.77	17.76	17.16
27	NextEra Energy, Inc.	18.72	17.90	19.80	27.80	31.30	28.90	24.40	18.30	14.17	12.90	16.81	15.05
28	NorthWestern Corp	16.88	16.00	13.70	17.30	17.40	18.60	18.17	17.27	15.07	12.77	21.58	N/A
29	OGE Energy	15.49	17.70	17.00	17.20	14.30	16.20	17.93	17.90	15.77	12.17	14.14	13.36
30	Otter Tail Corp.	20.31	12.90	14.30	9.50	12.30	18.30	22.60	19.07	30.10	30.65	17.25	17.04
31	Pinnacle West Capital	16.01	18.70	15.80	17.10	14.10	16.70	18.83	16.87	14.73	14.13	15.94	14.73
32	TXNM Energy	18.26	17.80	14.20	17.40	19.90	19.60	20.67	19.93	15.20	16.05	22.85	14.94
33	Portland General	16.56	13.70	14.30	18.20	17.70	16.60	20.23	17.37	14.43	14.23	17.63	N/A
34	PPL Corp.	16.39	19.70	16.20	20.00	54.10	13.90	14.07	13.60	11.40	18.40	15.51	11.39
35	Public Serv. Enterprise	14.76	20.20	18.80	18.50	16.80	15.70	16.97	14.00	12.23	11.33	17.02	11.61
36	SCANA Corp.	13.96	N/A	N/A	N/A	N/A	N/A	14.46	15.05	14.30	12.41	14.94	12.93
37	Sempra Energy	15.43	13.00	15.00	16.80	15.40	17.50	22.40	22.00	15.47	11.50	12.43	8.60
38	Southern Co.	16.48	21.10	18.60	19.60	18.40	17.90	16.07	16.53	16.33	14.83	16.04	14.72
39	Vectren Corp.	17.05	N/A	N/A	N/A	N/A	N/A	23.54	19.03	17.17	14.93	16.45	15.51
40	WEC Energy Group	17.50	19.00	16.50	21.90	22.30	24.90	21.03	19.63	15.50	14.03	15.64	13.47
41	Westar Energy	15.58	N/A	N/A	N/A	N/A	N/A	23.40	18.47	14.08	14.96	13.69	14.08
42	Xcel Energy Inc.	17.88	18.10	15.30	22.20	22.50	23.90	20.47	16.80	14.67	13.50	15.62	22.02
43	Average	17.06	17.99	16.29	20.28	20.85	19.66	19.97	17.79	15.68	14.15	16.95	15.11
44	Median	16.30	18.55	16.30	19.90	19.50	19.00	20.23	17.90	15.20	13.43	16.45	14.94

Sources:
The current year P/E ratio is based on the forward P/E (price over expected earnings per share). All historical year P/E ratios are based on annual average share price over achieved earnings per share.

[1] Data for years 2019 and prior were retrieved from the Value Line Investment Survey Investment Analyzer Software, downloaded on June 18, 2021.
Data for the years 2020 - 2024 was retrieved from Value Line Investment Surveys.

[2] The Value Line Investment Survey, March 7, April 18, and May 9, 2025.

Valley Energy, Inc. / Citizens' Electric Company of Lewisburg, PA / Wellsboro Electric Company

Electric Utilities
(Valuation Metrics)

Line	Company	Market Price to Cash Flow (MP/CF) Ratio [1] 23-Year Average	2024 [2]	2023	2022	2021	2020	3-Year Averages 2017-2019	2014-2016	2011-2013	2008-2010	2005-2007	2002-2004
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
1	ALLETE	9.12	8.03	6.69	7.56	8.61	8.14	10.83	8.19	8.41	8.61	10.97	11.46
2	Alliant Energy	8.31	9.74	9.43	10.43	10.31	10.66	11.22	9.31	7.41	6.77	7.01	5.16
3	Ameren Corp.	7.42	7.76	8.05	9.54	9.03	9.63	8.59	7.09	5.70	4.94	8.28	7.65
4	American Electric Power	6.77	7.70	7.68	8.67	7.57	8.41	8.72	7.22	5.99	5.32	6.15	5.13
5	Avangrid, Inc.	9.53	N/A	7.12	8.69	11.19	9.39	9.83	9.93	N/A	N/A	N/A	N/A
6	Avista Corp.	6.94	6.34	6.73	9.39	8.03	7.80	8.94	7.23	6.50	4.99	6.49	6.28
7	Black Hills	7.90	7.58	7.76	8.92	8.84	8.56	9.56	8.73	7.30	7.22	7.37	6.50
8	CenterPoint Energy	5.67	7.79	7.75	8.01	7.95	5.94	7.48	5.99	5.70	4.35	4.60	2.83
9	CMS Energy Corp.	6.60	8.53	8.28	9.43	9.27	9.87	9.00	7.72	6.04	3.85	4.67	3.04
10	Consol. Edison	8.24	8.34	8.26	8.70	7.26	8.35	9.28	8.42	8.08	7.00	8.52	8.28
11	Dominion Resources	9.86	9.08	9.24	9.35	11.15	14.59	11.92	11.90	10.08	7.79	8.85	7.24
12	DTE Energy	6.80	7.72	7.27	7.96	10.62	7.85	9.09	7.86	5.92	4.39	5.49	5.61
13	Duke Energy	7.60	7.47	7.17	7.75	7.89	8.06	7.82	8.21	8.07	6.37	7.16	N/A
14	Edison Int'l	6.02	6.04	5.67	6.83	7.14	7.57	9.25	6.12	4.76	4.56	6.16	4.21
15	El Paso Electric	5.93	N/A	N/A	N/A	N/A	N/A	8.99	6.75	5.71	4.41	6.45	4.31
16	Entergy Corp.	5.83	7.85	4.62	7.15	5.61	5.78	5.21	4.11	4.06	6.10	8.38	6.51
17	Eversource Energy	7.60	6.51	10.39	9.39	11.41	12.53	10.33	10.13	8.12	4.57	5.25	3.13
18	Evergy, Inc.	7.45	6.96	6.74	8.66	7.41	N/A	N/A	N/A	N/A	N/A	N/A	N/A
19	Exelon Corp.	6.05	6.06	6.41	7.69	5.08	4.44	4.93	4.86	5.34	6.91	8.82	5.66
20	FirstEnergy Corp.	6.92	7.47	7.90	8.93	6.60	9.23	8.23	5.98	6.97	5.66	7.15	5.72
21	Fortis Inc.	8.45	8.09	8.34	9.10	9.57	9.50	8.56	9.00	8.13	7.25	8.54	N/A
22	Great Plains Energy	6.89	N/A	N/A	N/A	N/A	N/A	14.62	7.25	5.85	5.75	7.17	5.86
23	Hawaiian Elec.	7.70	2.16	5.70	7.95	8.23	8.69	8.95	8.11	7.98	7.95	8.24	6.92
24	Hydro One Limited3	11.65	15.81	14.82	14.51	13.75	7.31	11.10	8.51	N/A	N/A	N/A	N/A
25	IDACORP, Inc.	9.05	10.78	11.04	12.42	11.84	11.38	12.01	9.64	7.16	6.31	7.83	7.31
26	MGE Energy	11.75	13.26	12.31	13.63	N/A	14.90	15.98	13.20	10.48	8.62	10.08	9.78
27	NextEra Energy, Inc.	9.29	11.24	10.89	15.17	20.40	15.48	11.57	8.38	7.05	6.26	7.42	6.15
28	NorthWestern Corp	7.87	7.33	8.01	8.65	8.83	8.88	8.98	8.88	6.78	5.47	8.39	8.13
29	OGE Energy	7.94	8.14	7.78	8.36	7.64	8.38	10.16	9.64	8.25	6.14	7.37	5.91
30	Otter Tail Corp.	9.25	8.91	8.02	7.70	8.61	9.99	11.70	9.29	9.02	9.24	8.79	8.49
31	Pinnacle West Capital	6.20	6.11	6.47	5.19	6.19	7.49	8.04	7.28	6.33	4.56	5.57	5.30
32	TXNM Energy	6.86	6.06	6.87	6.95	7.81	7.87	7.63	7.36	5.74	5.40	8.60	6.03
33	Portland General	6.00	5.90	6.56	6.65	6.48	6.72	7.22	6.45	5.33	4.52	5.54	N/A
34	PPL Corp.	7.93	9.95	7.83	8.82	13.74	7.46	8.37	8.14	6.14	8.48	8.02	5.73
35	Public Serv. Enterprise	8.12	11.78	9.68	10.53	11.32	8.22	8.96	7.24	6.28	6.90	8.95	6.73
36	SCANA Corp.	7.09	N/A	N/A	N/A	N/A	N/A	8.26	8.48	7.21	6.26	6.53	6.60
37	Sempra Energy	8.51	9.76	8.93	9.75	13.23	10.40	10.93	10.55	7.59	6.56	7.60	4.67
38	Southern Co.	8.35	9.59	8.64	9.63	8.72	8.34	7.78	8.49	8.42	7.68	8.50	8.13
39	Vectren Corp.	7.08	N/A	N/A	N/A	N/A	N/A	10.32	8.00	6.14	5.91	6.99	7.28
40	WEC Energy Group	9.25	9.53	10.12	11.81	11.99	13.67	11.58	11.37	9.08	7.53	7.17	5.15
41	Westar Energy	6.91	N/A	N/A	N/A	N/A	N/A	10.87	9.28	6.87	5.97	6.56	4.57
42	Xcel Energy Inc.	7.06	7.13	7.96	8.62	9.19	10.07	8.61	7.68	6.78	5.80	5.89	5.01
43	Average	7.70	8.29	8.19	9.15	9.40	9.21	9.55	8.24	6.99	6.22	7.37	6.18
44	Median	7.57	7.82	7.90	8.70	8.78	8.48	9.00	8.19	6.87	6.14	7.37	5.97

Sources:
The current year P/E ratio is based on the forward P/E (price over expected earnings per share). All historical year P/E ratios are based on annual average share price over achieved earnings per share.
[1] Data for years 2019 and prior were retrieved from the Value Line Investment Survey Investment Analyzer Software, downloaded on June 18, 2021.
Data for the years 2020 - 2024 was retrieved from Value Line Investment Surveys.
[2] The Value Line Investment Survey, March 7, April 18, and May 9, 2025.

Note:
[a] Based on the average of the high and low price and the projected Cash Flow per share.

Valley Energy, Inc. / Citizens' Electric Company of Lewisburg, PA / Wellsboro Electric Company

Electric Utilities
(Valuation Metrics)

		Market Price to Book Value (MP/BV) Ratio [1]										
		20-Year						3-Year Averages				
Line	Company	Average	2024 [2]	2023	2022	2021	2020	2017-2019	2014-2016	2011-2013	2008-2010	2005-2007
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	ALLETE	1.53	1.19	1.19	1.24	1.43	1.39	1.83	1.44	1.40	1.33	2.07
2	Alliant Energy	1.82	2.03	1.92	2.25	2.26	2.30	2.29	1.96	1.58	1.23	1.51
3	Ameren Corp.	1.61	1.90	2.00	2.15	2.13	2.21	2.04	1.53	1.12	0.95	1.64
4	American Electric Power	1.65	1.78	1.73	1.99	1.87	2.09	1.97	1.64	1.31	1.27	1.66
5	Avangrid, Inc.	0.90	N/A	0.71	0.89	1.01	0.97	0.99	0.78	N/A	N/A	N/A
6	Avista Corp.	1.32	1.11	1.19	1.33	1.42	1.37	1.72	1.42	1.22	1.04	1.24
7	Black Hills	1.49	1.15	1.28	1.54	1.52	1.55	1.87	1.77	1.32	1.04	1.56
8	CenterPoint Energy	2.25	1.78	1.86	1.99	1.74	1.90	2.33	2.48	2.05	2.07	2.98
9	CMS Energy Corp.	2.19	2.38	2.33	2.71	2.69	3.24	3.01	2.47	1.88	1.27	1.52
10	Consol. Edison	1.43	1.53	1.48	1.55	1.34	1.44	1.57	1.45	1.41	1.15	1.49
11	Dominion Resources	2.50	1.71	1.68	2.34	2.37	2.72	2.51	3.35	2.73	2.08	2.42
12	DTE Energy	1.67	2.10	1.97	2.41	2.82	1.80	1.99	1.70	1.35	1.05	1.35
13	Duke Energy	1.30	1.67	1.49	1.63	1.58	1.47	1.40	1.31	1.14	0.99	1.15
14	Edison Int'l	1.72	2.10	1.86	2.08	1.67	1.62	1.98	1.78	1.45	1.22	1.93
15	El Paso Electric	1.56	N/A	N/A	N/A	N/A	N/A	1.91	1.56	1.57	1.16	1.72
16	Entergy Corp.	1.74	1.81	1.45	1.81	1.75	1.93	1.84	1.47	1.29	1.91	2.18
17	Eversource Energy	1.55	1.48	1.71	1.86	2.00	2.11	1.80	1.55	1.39	1.25	1.29
18	Evergy, Inc.	1.41	1.29	1.33	1.52	1.50	N/A	N/A	N/A	N/A	N/A	N/A
19	Exelon Corp.	2.04	1.39	1.52	1.88	1.37	1.20	1.31	1.21	1.53	3.01	4.09
20	FirstEnergy Corp.	2.05	1.86	2.08	2.37	2.33	2.81	3.20	1.56	1.35	1.81	1.93
21	Fortis Inc.	1.47	1.37	1.43	1.56	1.48	1.47	1.35	1.31	1.55	1.45	1.79
22	Great Plains Energy	1.21	N/A	N/A	N/A	N/A	N/A	1.33	1.13	0.97	0.93	1.77
23	Hawaiian Elec.	1.65	1.50	1.24	1.94	1.81	1.82	1.85	1.61	1.57	1.40	1.78
24	Hydro One Limited3	1.58	2.12	1.89	1.83	1.64	1.44	1.41	1.34	N/A	N/A	N/A
25	IDACORP, Inc.	1.52	1.68	1.75	1.91	1.88	1.84	2.00	1.58	1.23	1.05	1.28
26	MGE Energy	2.17	2.59	2.35	2.47	N/A	2.54	2.78	2.26	1.91	1.60	1.89
27	NextEra Energy, Inc.	2.41	2.87	2.89	4.07	4.27	3.58	2.47	2.18	1.74	1.75	2.02
28	NorthWestern Corp	1.42	1.11	1.18	1.25	1.43	1.45	1.62	1.61	1.44	1.15	1.52
29	OGE Energy	1.81	1.67	1.62	1.74	1.67	1.86	1.88	1.92	2.03	1.53	1.90
30	Otter Tail Corp.	1.94	2.18	2.55	2.30	2.33	2.04	2.48	1.86	1.63	1.36	1.81
31	Pinnacle West Capital	1.42	1.42	1.42	1.31	1.45	1.63	1.85	1.56	1.37	1.03	1.25
32	TXNM Energy	1.37	1.49	1.75	1.81	1.86	1.87	1.98	1.36	0.96	0.64	1.30
33	Portland General	1.36	1.28	1.37	1.58	1.55	1.57	1.70	1.45	1.17	0.97	1.34
34	PPL Corp.	1.97	1.59	1.43	1.44	1.52	1.63	2.02	2.11	1.53	2.30	2.66
35	Public Serv. Enterprise	1.95	2.35	1.92	2.32	2.11	1.70	1.82	1.61	1.50	2.01	2.63
36	SCANA Corp.	1.51	N/A	N/A	N/A	N/A	N/A	1.65	1.56	1.44	1.32	1.66
37	Sempra Energy	1.79	1.74	1.65	1.84	1.64	1.84	2.17	2.12	1.55	1.42	1.77
38	Southern Co.	2.15	2.68	2.34	2.53	2.39	2.20	2.03	2.01	2.06	1.89	2.27
39	Vectren Corp.	1.83	N/A	N/A	N/A	N/A	N/A	2.75	2.16	1.64	1.46	1.77
40	WEC Energy Group	2.07	2.27	2.35	2.57	2.61	2.84	2.27	2.08	2.02	1.54	1.70
41	Westar Energy	1.37	N/A	N/A	N/A	N/A	N/A	1.94	1.63	1.27	1.04	1.35
42	Xcel Energy Inc.	1.73	1.77	2.00	2.22	2.27	2.46	2.12	1.70	1.47	1.27	1.44
43	Average	1.73	1.78	1.73	1.95	1.91	1.94	1.98	1.72	1.52	1.41	1.81
44	Median	1.71	1.73	1.71	1.88	1.74	1.84	1.94	1.61	1.45	1.27	1.72

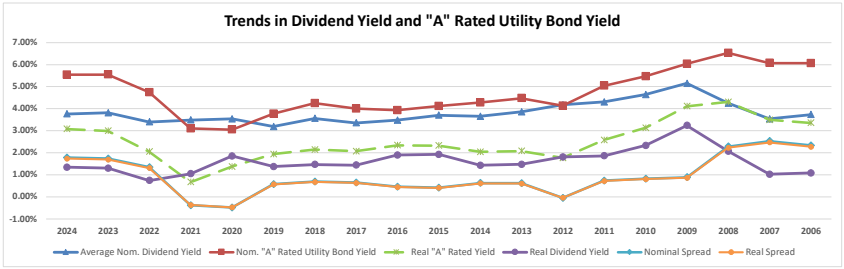
Sources:
The current year P/E ratio is based on the forward P/E (price over expected earnings per share). All historical year P/E ratios are based on annual average share price over achieved earnings per share.
[1] Data for years 2019 and prior were retrieved from the Value Line Investment Survey Investment Analyzer Software, downloaded on June 18, 2021.
Data for the years 2020 - 2024 was retrieved from Value Line Investment Surveys.
[2] The Value Line Investment Survey, March 7, April 18, and May 9, 2025.

Notes:
[b] Based on the average of the high and low price and the projected Book Value per share.

Valley Energy, Inc. / Citizens' Electric Company of Lewisburg, PA / Wellsboro Electric Company

Electric Utilities
(Valuation Metrics)

Line	Company	Dividend Yield[1] 19-Year Average	2024 [2/a]	2023	2022	2021	3-Year Averages 2018-2020	2015-2017	2012-2014	2009-2011	2006-2008
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	ALLETE	4.05%	4.63%	4.67%	4.47%	3.88%	3.29%	3.50%	4.10%	5.13%	3.71%
2	Alliant Energy	3.60%	3.46%	3.57%	3.04%	2.97%	2.99%	3.29%	3.78%	4.87%	3.52%
3	Ameren Corp.	4.07%	3.29%	3.13%	2.74%	2.74%	2.74%	3.53%	4.53%	5.67%	5.34%
4	American Electric Power	3.97%	3.96%	4.02%	3.41%	3.61%	3.33%	3.58%	4.21%	5.12%	3.89%
5	Avangrid, Inc.	3.89%	N/A	4.87%	3.94%	3.53%	3.57%	4.03%	N/A	N/A	N/A
6	Avista Corp.	3.93%	5.29%	4.85%	4.26%	3.94%	3.48%	3.50%	4.35%	4.60%	2.86%
7	Black Hills	3.77%	4.53%	4.15%	3.44%	3.50%	3.16%	3.05%	3.47%	5.20%	3.80%
8	CenterPoint Energy	4.08%	2.77%	2.71%	2.46%	2.77%	3.82%	4.85%	3.85%	5.31%	4.42%
9	CMS Energy Corp.	3.20%	3.23%	3.37%	2.92%	2.92%	2.77%	3.07%	3.84%	4.07%	1.93%
10	Consol. Edison	4.24%	3.43%	3.57%	3.51%	4.10%	3.66%	3.71%	4.23%	5.20%	5.18%
11	Dominion Resources	4.11%	5.06%	5.18%	3.66%	3.38%	4.60%	3.78%	3.76%	4.58%	3.56%
12	DTE Energy	3.96%	3.55%	3.67%	3.17%	3.06%	3.33%	3.34%	3.86%	5.24%	4.82%
13	Duke Energy	4.56%	3.92%	4.28%	3.98%	4.02%	4.35%	4.25%	4.46%	5.72%	4.80%
14	Edison Int'l	3.41%	4.17%	4.47%	4.45%	4.39%	3.95%	2.84%	2.82%	3.66%	2.49%
15	El Paso Electric	2.74%	N/A	N/A	N/A	N/A	2.55%	2.79%	2.98%	2.11%	N/A
16	Entergy Corp.	4.01%	3.62%	4.36%	3.70%	3.84%	3.83%	4.54%	4.81%	4.34%	2.71%
17	Eversource Energy	3.34%	4.72%	3.89%	3.09%	2.85%	2.92%	3.23%	3.47%	3.67%	3.04%
18	Evergy, Inc.	4.06%	4.58%	4.42%	3.66%	3.59%	N/A	N/A	N/A	N/A	N/A
19	Exelon Corp.	3.76%	4.08%	3.67%	2.89%	3.17%	3.40%	3.71%	4.70%	4.72%	2.70%
20	FirstEnergy Corp.	4.30%	4.23%	4.24%	3.71%	4.39%	4.28%	4.39%	4.47%	5.36%	3.24%
21	Fortis Inc.	3.73%	4.16%	4.09%	3.82%	3.77%	3.78%	3.75%	3.79%	3.86%	3.19%
22	Great Plains Energy	4.52%	N/A	N/A	N/A	N/A	N/A	3.66%	3.84%	4.55%	6.02%
23	Hawaiian Elec.	4.40%	N/A	4.09%	3.59%	3.44%	3.32%	3.90%	4.73%	5.81%	4.92%
24	Hydro One Limited	2.81%	2.11%	2.34%	2.50%	2.53%	3.22%	2.99%	N/A	N/A	N/A
25	IDACORP, Inc.	3.16%	3.24%	3.18%	2.86%	2.89%	2.67%	2.80%	3.20%	3.66%	3.63%
26	MGE Energy	2.95%	2.06%	2.25%	2.15%	N/A	2.07%	2.32%	2.98%	3.99%	4.21%
27	NextEra Energy, Inc.	2.90%	2.94%	2.80%	2.11%	1.90%	2.40%	2.90%	3.32%	3.93%	N/A
28	NorthWestern Corp	4.18%	5.01%	4.78%	4.51%	4.00%	3.72%	3.52%	3.71%	5.06%	4.37%
29	OGE Energy	3.86%	4.39%	4.63%	4.30%	4.81%	4.06%	3.66%	2.68%	3.90%	4.10%
30	Otter Tail Corp.	3.75%	2.15%	2.33%	2.44%	2.81%	3.04%	3.77%	4.49%	5.54%	3.67%
31	Pinnacle West Capital	4.50%	4.42%	4.51%	4.90%	4.44%	3.60%	3.50%	4.46%	5.67%	5.19%
32	TXNM Energy	3.18%	3.70%	3.27%	3.04%	2.09%	2.68%	2.71%	2.91%	4.01%	3.81%
33	Portland General	3.73%	4.45%	4.20%	3.63%	3.62%	3.19%	3.08%	3.71%	4.98%	3.39%
34	PPL Corp.	4.42%	3.40%	3.53%	3.23%	5.83%	5.56%	4.35%	4.78%	4.91%	3.06%
35	Public Serv. Enterprise	3.71%	3.16%	3.83%	3.37%	3.37%	3.44%	3.78%	4.28%	4.28%	3.15%
36	SCANA Corp.	4.37%	N/A	N/A	N/A	N/A	N/A	3.74%	4.15%	5.13%	4.48%
37	Sempra Energy	3.00%	3.06%	3.27%	2.99%	3.39%	3.11%	2.85%	3.12%	3.32%	2.39%
38	Southern Co.	4.52%	3.57%	4.13%	3.82%	4.17%	4.68%	4.61%	4.53%	5.10%	4.49%
39	Vectren Corp.	4.38%	N/A	N/A	N/A	N/A	N/A	3.23%	4.20%	5.48%	4.61%
40	WEC Energy Group	3.09%	3.75%	3.57%	3.08%	3.00%	2.96%	3.38%	3.38%	3.16%	2.24%
41	Westar Energy	4.37%	N/A	N/A	N/A	N/A	N/A	3.21%	4.24%	5.48%	4.55%
42	Xcel Energy Inc.	3.68%	3.64%	3.28%	2.90%	2.81%	2.86%	3.37%	3.86%	4.63%	4.39%
43	**Average**	**3.82%**	**3.76%**	**3.82%**	**3.40%**	**3.49%**	**3.41%**	**3.51%**	**3.90%**	**4.65%**	**3.83%**
44	Median	3.69%	3.70%	3.89%	3.41%	3.47%	3.33%	3.50%	3.86%	4.87%	3.80%
45	20-Yr Treasury Yields[3]	3.32%	4.50%	4.25%	3.30%	1.98%	2.26%	2.47%	2.91%	3.92%	4.75%
46	20-Yr TIPS[3]	1.12%	2.06%	1.73%	0.64%	-0.43%	0.41%	0.73%	0.61%	1.71%	2.28%
47	Implied Inflation[b]	2.17%	2.39%	2.48%	2.64%	2.42%	1.84%	1.73%	2.29%	2.17%	2.42%
48	**Real Dividend Yield[c]**	**1.61%**	**1.34%**	**1.30%**	**0.74%**	**1.04%**	**1.55%**	**1.75%**	**1.57%**	**2.42%**	**1.38%**
	A-Rated Utility										
49	**Nominal "A" Rated Yield[4]**	**4.74%**	**5.54%**	**5.55%**	**4.74%**	**3.10%**	**3.69%**	**4.01%**	**4.29%**	**5.51%**	**6.22%**
50	**Real "A" Rated Yield**	**2.52%**	**3.08%**	**2.99%**	**2.05%**	**0.67%**	**1.82%**	**2.24%**	**1.96%**	**3.27%**	**3.72%**
	Baa-Rated Utility										
51	**Nominal "Baa" Rated Yield**	**5.24%**	**5.76%**	**5.85%**	**5.05%**	**3.36%**	**4.10%**	**4.69%**	**4.87%**	**6.20%**	**6.63%**
52	**Real "Baa" Rated Yield**	**3.00%**	**3.29%**	**3.29%**	**2.35%**	**0.91%**	**2.22%**	**2.91%**	**2.52%**	**3.94%**	**4.11%**
	Spreads (A-Rated Utility Bond - Stock)										
53	**Nominal Spread[d]**	**0.92%**	**1.78%**	**1.73%**	**1.34%**	**-0.38%**	**0.28%**	**0.50%**	**0.40%**	**0.87%**	**2.39%**
54	**Real Spread[e]**	**0.90%**	**1.73%**	**1.69%**	**1.31%**	**-0.38%**	**0.27%**	**0.49%**	**0.39%**	**0.85%**	**2.33%**
	Spreads (Baa-Rated Utility Bond - Stock)										
55	**Nominal Spread[b]**	**1.41%**	**2.00%**	**2.03%**	**1.65%**	**-0.13%**	**0.69%**	**1.18%**	**0.97%**	**1.55%**	**2.80%**
56	**Real Spread[c]**	**1.38%**	**1.95%**	**1.98%**	**1.61%**	**-0.13%**	**0.67%**	**1.16%**	**0.95%**	**1.51%**	**2.73%**
	Spreads (Treasury Bond - Stock)										
57	**Nominal[f]**	**-0.51%**	**0.74%**	**0.44%**	**-0.10%**	**-1.51%**	**-1.15%**	**-1.04%**	**-0.98%**	**-0.73%**	**0.92%**
58	**Real[g]**	**-0.50%**	**0.72%**	**0.43%**	**-0.10%**	**-1.47%**	**-1.13%**	**-1.02%**	**-0.96%**	**-0.71%**	**0.90%**



Sources:
[1] Data for years 2019 and prior were retrieved from the Value Line Investment Survey Investment Analyzer Software, downloaded on June 18, 2021.
Data for the years 2020 - 2024 was retrieved from Value Line Investment Surveys.
[2] The Value Line Investment Survey, March 7, April 18, and May 9, 2025.
[3] St. Louis Federal Reserve: Economic Research, http://research.stlouisfed.org.
[4] Mergent Bond Record, through December 31, 2024.

Notes:
[a] Based on the average of the high and low price and the projected Dividends Declared per share, published in the Value Line Investment Survey.
[b] Line 47 = (1 + Line 45) / (1 + Line 46) - 1.
[c] Line 48 = (1 + Line 43) / (1 +Line 47) - 1.
[d] The spread being measured here is the nominal A-rated utility bond yield over the average nominal utility dividend yield; (Line 49 - Line 43).
[e] The spread being measured here is the real A-rated utility bond yield over the average real utility dividend yield; Line 50 - Line 48)
[f] The spread being measured here is the nominal 20-Year Treasury yield over the average nominal utility dividend yield; (Line 45 - Line 43).
[g] The spread being measured here is the real 20-Year TIPS yield over the average real utility dividend yield; Line 48 - Line 46)

Valley Energy, Inc. / Citizens' Electric Company of Lewisburg, PA / Wellsboro Electric Company

Electric Utilities
(Valuation Metrics)

		Dividend per Share[1]									
		19-Year					3-Year Averages				
Line	Company	Average	2024[2]	2023	2022	2021	2018-2020	2015-2017	2012-2014	2009-2011	2006-2008
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	ALLETE	2.09	2.82	2.71	2.60	2.52	2.35	2.08	1.90	1.77	1.60
2	Alliant Energy	1.16	1.92	1.81	1.71	1.61	1.43	1.18	0.95	0.80	0.64
3	Ameren Corp.	1.99	2.68	2.52	2.36	2.20	1.92	1.72	1.60	1.55	2.54
4	American Electric Power	2.30	3.57	3.37	3.17	3.00	2.69	2.27	1.95	1.73	1.57
5	Avangrid, Inc.	1.75	N/A	1.76	1.76	1.76	1.75	1.73	N/A	N/A	N/A
6	Avista Corp.	1.28	1.90	1.84	1.76	1.69	1.55	1.37	1.22	0.97	0.62
7	Black Hills	1.79	2.60	2.50	2.41	2.29	2.05	1.70	1.52	1.44	1.36
8	CenterPoint Energy	0.85	0.81	0.77	0.72	0.66	0.96	1.12	0.86	0.78	0.67
9	CMS Energy Corp.	1.20	2.06	1.95	1.84	1.74	1.53	1.24	1.02	0.67	0.28
10	Consol. Edison	2.70	3.32	3.24	3.16	3.10	2.96	2.68	2.47	2.38	2.32
11	Dominion Resources	2.43	2.67	2.67	2.67	2.52	3.49	2.81	2.25	1.85	1.47
12	DTE Energy	3.00	4.15	3.88	3.54	3.88	3.85	3.09	2.57	2.21	2.11
13	Duke Energy	3.37	4.14	4.06	3.98	3.90	3.74	3.36	3.09	2.90	2.64
14	Edison Int'l	1.93	3.17	2.99	2.84	2.69	2.49	1.98	1.39	1.27	1.17
15	El Paso Electric	1.11	N/A	N/A	N/A	N/A	1.42	1.24	1.04	0.66	N/A
16	Entergy Corp.	1.72	2.30	2.17	2.05	1.93	1.83	1.71	1.66	1.59	1.29
17	Eversource Energy	1.69	2.86	2.70	2.55	2.41	2.14	1.78	1.45	1.03	0.78
18	Evergy, Inc.	2.40	2.60	2.48	2.33	2.18	N/A	N/A	N/A	N/A	N/A
19	Exelon Corp.	1.61	1.52	1.44	1.35	1.53	1.45	1.27	1.60	2.10	1.84
20	FirstEnergy Corp.	1.77	1.70	1.60	1.56	1.56	1.64	1.44	1.76	2.20	2.03
21	Fortis Inc.	1.51	2.39	2.29	2.17	2.08	1.86	1.54	1.25	1.11	0.83
22	Great Plains Energy	1.11	N/A	N/A	N/A	N/A	N/A	1.05	0.89	0.83	1.66
23	Hawaiian Elec.	1.25	N/A	1.08	1.40	1.36	1.28	1.24	1.24	1.24	1.24
24	Hydro One Limited	0.77	0.90	0.86	0.86	0.75	0.74	0.69	N/A	N/A	N/A
25	IDACORP, Inc.	2.02	3.35	3.20	3.04	2.88	2.56	2.08	1.57	1.20	1.20
26	MGE Energy	1.21	1.76	1.67	1.59	N/A	1.38	1.21	1.07	0.99	0.94
27	NextEra Energy, Inc.	0.96	2.06	1.87	1.70	1.54	1.25	0.87	0.66	0.51	0.41
28	NorthWestern Corp	1.88	2.60	2.56	2.52	2.48	2.30	2.01	1.53	1.38	1.28
29	OGE Energy	1.13	1.68	1.66	1.64	1.63	1.49	1.16	0.87	0.74	0.68
30	Otter Tail Corp.	1.34	1.87	1.75	1.65	1.56	1.41	1.25	1.20	1.19	1.17
31	Pinnacle West Capital	2.65	3.55	3.49	3.42	3.36	3.05	2.57	2.41	2.10	2.08
32	TXNM Energy	0.92	1.57	1.49	1.41	0.98	1.17	0.89	0.67	0.50	0.79
33	Portland General	1.30	1.98	1.88	1.79	1.70	1.51	1.26	1.10	1.03	0.86
34	PPL Corp.	1.38	1.03	0.95	0.88	1.66	1.65	1.53	1.47	1.39	1.22
35	Public Serv. Enterprise	1.66	2.40	2.28	2.16	2.04	1.88	1.64	1.45	1.36	1.20
36	SCANA Corp.	2.00	N/A	N/A	N/A	N/A	N/A	2.31	2.04	1.91	1.76
37	Sempra Energy	2.68	2.48	2.38	4.58	4.40	3.88	3.04	2.52	1.68	1.27
38	Southern Co.	2.17	2.86	2.78	2.70	2.62	2.46	2.23	2.01	1.80	1.60
39	Vectren Corp.	1.42	N/A	N/A	N/A	N/A	N/A	1.62	1.43	1.37	1.27
40	WEC Energy Group	1.75	3.34	3.12	2.91	2.71	2.37	1.93	1.40	0.84	0.50
41	Westar Energy	1.30	N/A	N/A	N/A	N/A	N/A	1.52	1.36	1.24	1.07
42	Xcel Energy Inc.	1.37	2.19	2.08	1.95	1.83	1.62	1.36	1.13	1.00	0.91
43	**Average**	**1.74**	**2.42**	**2.27**	**2.24**	**2.19**	**2.03**	**1.73**	**1.53**	**1.37**	**1.29**
44	**Industry Average Growth**	**3.95%**	**6.91%**	**1.35%**	**2.21%**	**2.43%**	**5.38%**	**5.18%**	**3.52%**	**1.68%**	**5.43%**

Sources:

[1] Data for years 2019 and prior were retrieved from the Value Line Investment Survey Investment Analyzer Software, downloaded on June 18, 2021. Data for the years 2020 - 2024 was retrieved from Value Line Investment Surveys.

[2] The Value Line Investment Survey, March 7, April 18, and May 9, 2025.

Valley Energy, Inc. / Citizens' Electric Company of Lewisburg, PA / Wellsboro Electric Company

Electric Utilities
(Valuation Metrics)

		Earnings per Share[1]									
		19-Year					3-Year Averages				
Line	Company	Average	2024[2]	2023	2022	2021	2018-2020	2015-2017	2012-2014	2009-2011	2006-2008
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	ALLETE	3.01	3.10	4.30	3.38	3.23	3.35	3.22	2.70	2.24	2.89
2	Alliant Energy	1.86	2.69	2.78	2.73	2.63	2.33	1.78	1.64	1.23	1.22
3	Ameren Corp.	3.07	4.59	4.37	4.14	3.84	3.39	2.61	2.30	2.67	2.84
4	American Electric Power	3.77	5.61	5.24	5.09	4.96	4.13	3.81	3.17	2.90	2.90
5	Avangrid, Inc.	1.88	N/A	2.09	2.32	1.97	2.02	1.50	N/A	N/A	N/A
6	Avista Corp.	1.85	2.29	2.24	2.12	2.10	2.31	2.00	1.67	1.65	1.18
7	Black Hills	2.77	3.91	3.91	3.97	3.74	3.58	2.95	2.49	1.66	1.69
8	CenterPoint Energy	1.25	1.58	1.37	1.59	0.94	1.17	1.22	1.34	1.12	1.27
9	CMS Energy Corp.	1.91	3.33	3.01	2.84	2.58	2.45	2.01	1.64	1.24	0.84
10	Consol. Edison	3.99	5.38	5.04	4.55	4.74	4.19	4.03	3.80	3.39	3.26
11	Dominion Resources	2.85	2.77	1.99	4.11	3.19	2.42	3.39	2.96	2.76	2.52
12	DTE Energy	4.68	6.77	6.76	5.52	4.10	6.52	5.00	4.25	3.55	2.61
13	Duke Energy	4.19	5.90	5.56	5.27	4.93	4.37	4.01	3.94	3.85	3.12
14	Edison Int'l	3.32	4.91	4.76	1.60	2.00	1.48	4.20	4.22	3.27	3.43
15	El Paso Electric	2.02	N/A	N/A	N/A	N/A	2.07	2.28	2.24	2.02	1.54
16	Entergy Corp.	3.15	2.45	5.55	2.69	3.44	3.18	2.98	2.79	3.42	2.86
17	Eversource Energy	2.79	4.57	4.34	4.09	3.54	3.42	2.94	2.32	2.08	1.42
18	Evergy, Inc.	3.52	3.80	3.17	3.26	3.83	N/A	N/A	N/A	N/A	N/A
19	Exelon Corp.	2.82	2.45	2.38	2.26	1.74	2.56	2.37	2.11	3.97	3.88
20	FirstEnergy Corp.	2.58	2.63	2.56	2.41	2.69	1.67	2.28	1.98	2.82	4.14
21	Fortis Inc.	2.10	3.28	3.10	2.78	2.61	2.60	2.22	1.55	1.62	1.39
22	Great Plains Energy	1.33	N/A	N/A	N/A	N/A	N/A	0.97	1.51	1.27	1.54
23	Hawaiian Elec.	2.09	10.42	1.81	2.20	2.25	1.88	1.81	1.64	1.19	1.17
24	Hydro One Limited	1.52	1.92	1.81	1.75	1.61	1.47	1.23	N/A	N/A	N/A
25	IDACORP, Inc.	3.82	5.50	5.14	5.11	4.85	4.60	4.01	3.62	2.98	2.13
26	MGE Energy	2.19	3.45	3.25	3.07	N/A	2.51	2.15	2.11	1.63	1.49
27	NextEra Energy, Inc.	1.65	3.43	3.17	2.90	1.81	1.90	1.53	1.25	1.13	0.88
28	NorthWestern Corp	2.73	3.27	3.22	3.29	3.60	3.33	3.21	2.57	2.23	1.51
29	OGE Energy	1.82	2.19	2.07	2.25	2.36	2.15	1.77	1.90	1.52	1.26
30	Otter Tail Corp.	2.47	7.17	7.00	6.78	4.23	2.19	1.67	1.32	0.51	1.52
31	Pinnacle West Capital	3.85	5.24	4.41	4.26	5.47	4.73	4.10	3.58	2.78	2.75
32	TXNM Energy	1.64	2.74	2.82	2.69	2.27	2.03	1.74	1.39	0.84	0.86
33	Portland General	2.08	3.14	2.38	2.74	2.72	2.16	2.16	1.94	1.64	1.62
34	PPL Corp.	2.12	1.68	1.60	1.41	0.53	2.33	2.42	2.46	2.03	2.46
35	Public Serv. Enterprise	2.99	3.68	3.48	3.47	2.55	3.42	2.98	2.63	3.09	2.45
36	SCANA Corp.	3.30	N/A	N/A	N/A	N/A	N/A	4.06	3.44	2.93	2.76
37	Sempra Energy	4.95	4.65	4.61	9.21	4.01	6.01	4.70	4.40	4.42	4.31
38	Southern Co.	2.90	4.06	3.64	3.61	3.42	3.14	2.96	2.71	2.41	2.21
39	Vectren Corp.	1.94	N/A	N/A	N/A	N/A	N/A	2.51	1.87	1.72	1.63
40	WEC Energy Group	2.88	4.89	4.63	4.46	4.11	3.57	2.81	2.48	1.90	1.42
41	Westar Energy	1.96	N/A	N/A	N/A	N/A	N/A	2.26	2.26	1.62	1.68
42	Xcel Energy Inc.	2.22	3.50	3.35	3.17	2.96	2.63	2.20	1.93	1.59	1.39
43	**Average**	**2.71**	**3.97**	**3.59**	**3.49**	**3.10**	**2.95**	**2.68**	**2.47**	**2.23**	**2.10**
44	**Industry Average Growth**	**3.93%**	**10.53%**	**2.96%**	**12.60%**	**1.28%**	**3.44%**	**2.66%**	**3.36%**	**3.58%**	**2.13%**

Sources:
[1] Data for years 2019 and prior were retrieved from the Value Line Investment Survey Investment Analyzer Software, downloaded on June 18, 2021.
Data for the years 2020 - 2024 was retrieved from Value Line Investment Surveys.
[2] The Value Line Investment Survey, March 7, April 18, and May 9, 2025.

Valley Energy, Inc. / Citizens' Electric Company of Lewisburg, PA / Wellsboro Electric Company

Electric Utilities
(Valuation Metrics)

Line	Company	Cash Flow / Capital Spending[1] 2020 (1)	2021 (2)	2022 (3)	2023 (4)	2024 (5)	2025[2] (6)	3 - 5 yr[2] Projection (7)
1	ALLETE	0.74x	0.80x	2.26x	1.42x	2.21x	1.36x	1.39x
2	Alliant Energy	0.82x	0.97x	0.94x	0.95x	0.97x	1.04x	1.27x
3	Ameren Corp.	0.51x	0.59x	0.72x	0.74x	0.84x	0.88x	0.98x
4	American Electric Power	0.74x	0.69x	0.73x	0.72x	0.82x	0.87x	1.11x
5	Avista Corp.	0.85x	0.87x	0.83x	0.78x	0.84x	0.95x	0.77x
6	Black Hills	0.72x	0.76x	0.85x	0.82x	0.68x	0.67x	0.73x
7	CenterPoint Energy	0.88x	0.62x	0.62x	0.57x	0.55x	0.52x	0.53x
8	CMS Energy Corp.	0.82x	0.77x	0.78x	0.92x	0.80x	0.61x	0.95x
9	Consol. Edison	0.82x	0.89x	0.83x	0.72x	0.84x	0.88x	0.99x
10	Dominion Resources	1.00x	0.89x	0.74x	0.63x	0.51x	0.53x	0.70x
11	DTE Energy	0.67x	0.70x	0.75x	0.82x	0.87x	0.90x	1.01x
12	Duke Energy	0.86x	0.93x	0.81x	0.79x	0.77x	0.92x	1.01x
13	Edison Int'l	0.67x	0.74x	0.67x	0.75x	0.82x	0.85x	0.90x
14	El Paso Electric	1.00x	0.83x	N/A	N/A	N/A	N/A	N/A
15	Entergy Corp.	0.81x	1.05x	0.98x	0.85x	0.81x	0.73x	0.75x
16	Eversource Energy	0.95x	0.74x	0.72x	0.86x	0.76x	0.74x	0.80x
17	Evergy, Inc.	1.06x	0.96x	0.94x	0.86x	0.86x	0.92x	1.01x
18	Exelon Corp.	1.30x	1.32x	0.96x	0.99x	0.80x	0.83x	0.93x
19	FirstEnergy Corp.	0.96x	0.91x	0.86x	0.80x	0.82x	0.64x	0.71x
20	Fortis Inc.	0.60x	0.74x	0.75x	0.82x	0.85x	0.89x	0.98x
21	Hawaiian Elec.	1.10x	1.42x	1.30x	1.51x	1.20x	1.29x	1.40x
22	Hydro One Electric	1.21x	0.67x	0.72x	0.63x	0.60x	0.63x	0.63x
23	IDACORP, Inc.	1.25x	1.16x	0.83x	0.63x	0.56x	0.56x	0.55x
24	MGE Energy	0.73x	0.87x	N/A	1.26x	1.10x	0.95x	1.10x
25	NextEra Energy, Inc.	0.58x	0.69x	0.54x	0.59x	0.59x	0.60x	0.69x
26	NorthWestern Corp	0.98x	0.82x	0.66x	0.75x	0.87x	0.86x	0.98x
27	OGE Energy	1.43x	1.13x	0.99x	0.97x	0.99x	1.06x	1.28x
28	Otter Tail Corp.	0.45x	1.42x	1.45x	1.08x	1.46x	1.47x	1.09x
29	Pinnacle West Capital	0.98x	0.85x	0.78x	0.95x	0.74x	0.77x	0.93x
30	TXNM Energy	0.59x	0.51x	0.63x	0.63x	0.53x	0.52x	0.56x
31	Portland General	0.75x	0.97x	1.01x	0.58x	0.62x	0.71x	0.87x
32	PPL Corp.	1.06x	1.12x	1.35x	0.98x	0.97x	1.00x	1.06x
33	Public Serv. Enterprise	1.00x	1.05x	0.82x	0.87x	0.90x	0.90x	0.97x
34	Sempra Energy	0.92x	0.78x	0.92x	0.96x	0.63x	0.59x	0.69x
35	Southern Co.	1.01x	0.93x	0.97x	0.97x	0.90x	0.97x	1.15x
36	WEC Energy Group	0.70x	0.75x	0.87x	0.92x	1.01x	1.09x	1.35x
37	Xcel Energy Inc.	0.99x	0.86x	0.80x	0.92x	0.65x	0.61x	0.90x
38	Average	0.88x	0.89x	0.90x	0.86x	0.85x	0.84x	0.94x
39	Median	0.86x	0.86x	0.83x	0.84x	0.82x	0.86x	0.96x

Source:
[1] Data for the years 2020 - 2024 was retrieved from Value Line Investment Surveys.
[2] The Value Line Investment Survey, March 7, April 18, and May 9, 2025.
Notes:
Based on the projected Cash Flow per share and Capital Spending per share.

Valley Energy, Inc. / Citizens' Electric Company of Lewisburg, PA / Wellsboro Electric Company

Electric Utilities
(Valuation Metrics)

Line	Company	Percent Dividends to Book Value [1] 18-Year Average	2024 [2/a]	2023	2022	2021	3-Year Averages 2018-2020	2015-2017	2012-2014	2009-2011	2006-2008
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	ALLETE	5.88%	5.51%	5.56%	5.52%	5.56%	5.47%	5.40%	5.83%	6.44%	6.73%
2	Alliant Energy	6.42%	7.04%	6.84%	6.84%	6.73%	6.75%	6.99%	6.43%	6.10%	5.25%
3	Ameren Corp.	6.04%	6.26%	6.26%	5.88%	5.84%	5.82%	5.88%	5.87%	4.74%	7.85%
4	American Electric Power	6.38%	7.05%	6.95%	6.80%	6.74%	6.75%	6.25%	5.94%	6.03%	6.28%
5	Avangrid, Inc.	3.15%	N/A	3.46%	3.51%	3.57%	3.57%	2.36%	N/A	N/A	N/A
6	Avista Corp.	5.11%	5.87%	5.78%	5.65%	5.61%	5.47%	5.38%	5.49%	4.91%	3.49%
7	Black Hills	5.32%	5.19%	5.30%	5.32%	5.32%	5.32%	5.63%	5.18%	5.18%	5.35%
8	CenterPoint Energy	9.08%	4.95%	5.03%	4.90%	4.82%	7.96%	12.50%	8.41%	9.87%	12.21%
9	CMS Energy Corp.	6.76%	7.69%	7.84%	7.89%	7.87%	8.58%	8.25%	7.96%	5.78%	1.81%
10	Consol. Edison	5.94%	5.24%	5.29%	5.42%	5.48%	5.50%	5.70%	5.91%	6.30%	7.04%
11	Dominion Resources	10.08%	8.66%	8.69%	8.54%	8.00%	11.14%	11.88%	11.63%	9.35%	8.52%
12	DTE Energy	6.32%	7.43%	7.25%	7.64%	8.64%	6.38%	6.08%	5.72%	5.56%	5.99%
13	Duke Energy	5.53%	6.54%	6.37%	6.47%	6.34%	6.18%	5.73%	5.32%	5.73%	3.52%
14	Edison Int'l	5.82%	8.76%	8.30%	9.24%	7.36%	7.09%	5.53%	4.48%	4.06%	4.46%
15	El Paso Electric	2.94%	N/A	N/A	N/A	N/A	5.04%	4.64%	4.57%	1.16%	0.00%
16	Entergy Corp.	6.69%	6.55%	6.32%	6.68%	6.72%	7.21%	7.31%	6.17%	6.65%	6.27%
17	Eversource Energy	5.19%	6.97%	6.66%	5.74%	5.69%	5.57%	5.27%	4.77%	4.76%	4.14%
18	Evergy, Inc.	5.62%	5.90%	5.90%	5.57%	5.41%	5.32%	N/A	N/A	N/A	N/A
19	Exelon Corp.	6.95%	5.67%	5.59%	5.42%	4.36%	4.45%	4.39%	6.19%	10.30%	11.70%
20	FirstEnergy Corp.	8.74%	7.87%	8.81%	8.78%	10.26%	12.46%	10.48%	5.79%	7.54%	7.20%
21	Fortis Inc.	5.44%	5.72%	5.84%	5.95%	5.59%	5.17%	4.99%	5.54%	5.74%	5.31%
22	Great Plains Energy	5.31%	N/A	N/A	N/A	N/A	N/A	4.42%	3.95%	3.92%	8.94%
23	Hawaiian Elec.	7.09%	N/A	5.07%	6.96%	6.22%	6.18%	6.62%	7.33%	7.88%	8.47%
24	Hydro One Limited	2.29%	4.47%	4.42%	4.57%	4.13%	4.57%	4.07%	0.00%	0.00%	0.00%
25	IDACORP, Inc.	4.74%	5.43%	5.57%	5.48%	5.45%	5.23%	4.86%	4.23%	3.87%	4.49%
26	MGE Energy	6.07%	5.33%	5.30%	5.32%	N/A	5.47%	5.74%	6.02%	6.55%	7.29%
27	NextEra Energy, Inc.	6.79%	8.46%	8.08%	8.61%	8.13%	6.78%	6.51%	6.40%	5.98%	6.24%
28	NorthWestern Corp	5.81%	5.58%	5.63%	5.65%	5.73%	5.74%	5.77%	5.56%	6.07%	6.09%
29	OGE Energy	6.88%	7.35%	7.49%	7.47%	8.04%	7.65%	6.53%	5.70%	6.28%	7.32%
30	Otter Tail Corp.	6.91%	4.69%	5.95%	5.61%	6.54%	7.18%	7.43%	8.06%	6.88%	6.59%
31	Pinnacle West Capital	6.21%	6.26%	6.41%	6.40%	6.43%	6.31%	5.96%	6.37%	6.21%	6.00%
32	TXNM Energy	4.11%	5.50%	5.72%	5.52%	3.88%	5.31%	4.23%	3.17%	2.68%	3.74%
33	Portland General	4.94%	5.71%	5.73%	5.75%	5.61%	5.26%	4.79%	4.66%	4.87%	4.12%
34	PPL Corp.	8.34%	5.40%	5.03%	4.66%	8.89%	9.81%	10.27%	7.57%	8.40%	8.78%
35	Public Serv. Enterprise	6.99%	7.42%	7.34%	7.82%	7.12%	6.26%	6.20%	6.36%	7.20%	8.36%
36	SCANA Corp.	6.44%	N/A	N/A	N/A		N/A	6.04%	6.15%	6.61%	6.98%
37	Sempra Energy	5.33%	5.32%	5.41%	5.49%	5.56%	6.31%	6.08%	5.67%	4.37%	4.09%
38	Southern Co.	9.56%	9.58%	9.65%	9.67%	9.96%	9.65%	9.34%	9.36%	9.38%	9.88%
39	Vectren Corp.	7.71%	N/A	N/A	N/A	N/A	N/A	7.61%	7.54%	7.78%	7.90%
40	WEC Energy Group	6.53%	8.54%	8.38%	7.92%	7.83%	7.37%	6.76%	7.44%	5.13%	3.76%
41	Westar Energy	5.71%	N/A	N/A	N/A	N/A	N/A	5.68%	5.69%	5.82%	5.65%
42	Xcel Energy Inc.	6.20%	6.44%	6.55%	6.43%	6.38%	6.38%	6.26%	5.87%	5.99%	6.16%
43	Average	6.25%	6.47%	6.37%	6.41%	6.44%	6.54%	6.39%	6.01%	5.95%	6.10%
44	Median	6.06%	6.26%	5.95%	5.88%	6.28%	6.22%	5.96%	5.87%	6.01%	6.20%

Sources:

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[2] The Value Line Investment Survey, March 7, April 18, and May 9, 2025.

[a] Based on the projected 2024 Dividend Declared per share and Book Value per share, published in The Value Line Investment Survey, March 7, April 18, and May 9, 2025.

Valley Energy, Inc. / Citizens' Electric Company of Lewisburg, PA / Wellsboro Electric Company

Electric Utilities
(Valuation Metrics)

Line	Company	Dividends to Earnings Ratio [1] 18-Year Average	2024 [2/a]	2023	2022	2021	3-Year Averages 2018-2020	2015-2017	2012-2014	2009-2011	2006-2008
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	ALLETE	0.70	0.91	0.63	0.77	0.78	0.70	0.65	0.70	0.80	0.56
2	Alliant Energy	0.62	0.71	0.65	0.63	0.61	0.61	0.67	0.58	0.66	0.53
3	Ameren Corp.	0.66	0.58	0.58	0.57	0.57	0.57	0.66	0.70	0.58	0.90
4	American Electric Power	0.61	0.64	0.64	0.62	0.60	0.65	0.60	0.62	0.60	0.54
5	Avangrid, Inc.	0.88	N/A	0.84	0.76	0.89	0.87	0.95	N/A	N/A	N/A
6	Avista Corp.	0.69	0.83	0.82	0.83	0.80	0.70	0.69	0.74	0.59	0.57
7	Black Hills	1.04	0.66	0.64	0.61	0.61	0.57	0.58	0.62	0.98	2.96
8	CenterPoint Energy	0.71	0.51	0.56	0.45	0.70	0.93	0.94	0.65	0.70	0.53
9	CMS Energy Corp.	0.58	0.62	0.65	0.65	0.67	0.62	0.62	0.62	0.54	0.30
10	Consol. Edison	0.68	0.62	0.64	0.69	0.65	0.71	0.67	0.65	0.70	0.71
11	Dominion Resources	0.89	0.96	1.34	0.65	0.79	1.53	0.83	0.76	0.67	0.59
12	DTE Energy	0.66	0.61	0.57	0.64	0.95	0.59	0.62	0.61	0.62	0.81
13	Duke Energy	0.80	0.70	0.73	0.76	0.79	0.86	0.84	0.79	0.76	0.80
14	Edison Int'l	0.48	0.65	0.63	1.78	1.35	0.06	0.47	0.33	0.39	0.34
15	El Paso Electric	0.50	N/A	N/A	N/A	N/A	0.68	0.54	0.46	0.27	N/A
16	Entergy Corp.	0.56	0.94	0.39	0.76	0.56	0.58	0.58	0.60	0.47	0.45
17	Eversource Energy	0.60	0.63	0.62	0.62	0.68	0.63	0.61	0.63	0.49	0.61
18	Evergy, Inc.	0.69	0.68	0.78	0.71	0.57	N/A	N/A	N/A	N/A	N/A
19	Exelon Corp.	0.60	0.62	0.61	0.60	0.88	0.58	0.55	0.77	0.53	0.47
20	FirstEnergy Corp.	0.78	0.65	0.63	0.65	0.58	1.01	0.64	1.09	0.84	0.49
21	Fortis Inc.	0.72	0.73	0.74	0.78	0.80	0.71	0.71	0.81	0.68	0.60
22	Great Plains Energy	- 0.82	N/A	N/A	N/A	N/A	N/A	- 5.65	0.59	0.67	1.12
23	Hawaiian Elec.	0.82	N/A	0.60	0.64	0.60	0.68	0.71	0.75	1.08	1.07
24	Hydro One Limited	0.92	0.47	0.48	0.49	0.47	1.87	0.57	N/A	N/A	N/A
25	IDACORP, Inc.	0.52	0.61	0.62	0.59	0.59	0.56	0.52	0.43	0.41	0.57
26	MGE Energy	0.56	0.51	0.51	0.52	N/A	0.55	0.56	0.51	0.61	0.63
27	NextEra Energy, Inc.	0.56	0.60	0.59	0.59	0.85	0.66	0.57	0.53	0.45	0.47
28	NorthWestern Corp	0.70	0.80	0.80	0.77	0.69	0.69	0.63	0.60	0.62	0.86
29	OGE Energy	0.61	0.77	0.80	0.73	0.69	0.70	0.66	0.45	0.49	0.54
30	Otter Tail Corp.	0.95	0.26	0.25	0.24	0.37	0.64	0.75	0.93	2.48	0.81
31	Pinnacle West Capital	0.70	0.68	0.79	0.80	0.61	0.64	0.63	0.67	0.77	0.78
32	TXNM Energy	0.84	0.57	0.53	0.52	0.43	0.58	0.51	0.48	0.63	2.40
33	Portland General	0.63	0.63	0.79	0.65	0.63	0.72	0.58	0.57	0.65	0.56
34	PPL Corp.	0.77	0.61	0.59	0.62	3.13	0.72	0.64	0.60	0.77	0.50
35	Public Serv. Enterprise	0.56	0.65	0.66	0.62	0.80	0.56	0.55	0.55	0.44	0.50
36	SCANA Corp.	0.61	N/A	N/A	N/A		N/A	0.57	0.59	0.65	0.64
37	Sempra Energy	0.54	0.53	0.52	0.50	1.10	0.65	0.65	0.57	0.38	0.29
38	Southern Co.	0.75	0.70	0.76	0.75	0.77	0.78	0.75	0.74	0.75	0.72
39	Vectren Corp.	0.75	N/A	N/A	N/A	N/A	N/A	0.65	0.77	0.80	0.78
40	WEC Energy Group	0.57	0.68	0.67	0.65	0.66	0.66	0.69	0.56	0.44	0.35
41	Westar Energy	0.68	N/A	N/A	N/A	N/A	N/A	0.67	0.60	0.78	0.66
42	Xcel Energy Inc.	0.62	0.63	0.62	0.62	0.62	0.62	0.62	0.58	0.63	0.66
43	Average	0.66	0.66	0.66	0.67	0.77	0.72	0.49	0.64	0.68	0.73
44	Median	0.63	0.64	0.63	0.64	0.68	0.66	0.63	0.61	0.63	0.59

Sources:

[1] Data for years 2019 and prior were retrieved from the Value Line Investment Survey Investment Analyzer Software, downloaded on June 18, 2021. Data for the years 2020 - 2024 was retrieved from Value Line Investment Surveys.

[2] The Value Line Investment Survey, March 7, April 18, and May 9, 2025.

Note:

[b] Based on the projected 2024 Dividends Declared per share and Earnings per share, published in The Value Line Investment Survey, March 7, April 18, and May 9, 2025.

Valley Energy, Inc. / Citizens' Electric Company of Lewisburg, PA / Wellsboro Electric Company

Electric Utilities
(Valuation Metrics)

Line	Company	Cash Flow to Capital Spending Ratio [1] 18-Year Average	2024 [2/a]	2023	2022	2021	3-Year Averages 2018-2020	2015-2017	2012-2014	2009-2011	2006-2008
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	ALLETE	0.94	1.30	1.76	2.12	0.55	0.80	1.37	0.54	0.60	0.78
2	Alliant Energy	0.79	0.65	0.74	0.91	0.95	N/A	0.65	0.83	0.65	0.96
3	Ameren Corp.	0.86	0.83	0.78	0.71	0.62	0.74	0.75	0.91	1.16	0.95
4	American Electric Power	0.86	0.84	0.79	0.81	0.81	0.75	0.79	0.95	1.15	0.74
5	Avangrid, Inc.	0.71	N/A	0.66	0.79	0.56	0.68	0.77	N/A	N/A	N/A
6	Avista Corp.	0.89	0.85	0.88	0.73	0.88	0.86	0.79	0.82	1.02	1.02
7	Black Hills	0.68	0.68	0.95	0.86	0.61	0.67	0.84	0.72	0.47	0.55
8	CenterPoint Energy	0.96	0.66	0.53	0.52	0.73	0.85	1.09	1.25	1.00	1.07
9	CMS Energy Corp.	0.86	0.74	0.85	0.82	0.78	0.78	0.84	0.79	1.05	0.91
10	Consol. Edison	0.83	0.84	0.84	0.88	0.83	0.84	0.72	0.92	0.88	0.75
11	Dominion Resources	0.75	0.41	0.46	0.86	0.73	0.91	0.70	0.71	0.80	0.81
12	DTE Energy	0.97	0.87	0.85	0.86	0.74	0.80	0.90	0.97	1.37	1.03
13	Duke Energy	0.89	0.89	0.81	0.87	0.85	0.82	0.88	1.05	0.81	0.93
14	Edison Int'l	0.75	0.85	0.83	0.62	0.55	0.52	0.88	0.79	0.67	0.91
15	El Paso Electric	0.87	N/A	N/A	N/A	0.83	0.86	0.86	0.77	0.90	0.96
16	Entergy Corp.	0.95	0.72	1.03	0.62	0.74	0.76	0.97	1.03	1.14	1.07
17	Eversource Energy	0.83	0.76	0.54	0.89	0.80	0.80	0.86	0.96	0.94	0.70
18	Evergy, Inc.	0.90	0.88	0.90	0.78	1.03	N/A	N/A	N/A	N/A	N/A
19	Exelon Corp.	1.18	0.81	0.82	0.84	1.09	1.12	0.88	0.99	1.50	1.77
20	FirstEnergy Corp.	0.99	0.77	0.82	0.98	0.83	0.80	0.96	0.77	1.20	1.42
21	Fortis Inc.	0.71	0.88	0.93	0.89	0.65	0.68	0.72	0.70	0.66	0.62
22	Great Plains Energy	0.79	N/A	N/A	N/A		N/A	0.95	0.85	0.80	0.56
23	Hawaiian Elec.	1.22	2.99	1.14	1.56	1.27	1.07	1.05	0.98	1.19	1.09
24	Hydro One Limited	0.89	0.60	0.63	0.72	1.21	0.96	0.97	N/A	N/A	N/A
25	IDACORP, Inc.	1.06	0.51	0.75	1.00	1.33	1.40	1.21	1.26	0.87	0.79
26	MGE Energy	1.08	1.02	0.98	1.12	0.82	0.82	1.41	1.10	1.42	0.75
27	NextEra Energy, Inc.	0.60	0.52	0.50	0.55	0.58	0.60	0.62	0.61	0.63	0.64
28	NorthWestern Corp	0.99	0.79	0.72	0.75	0.84	1.07	1.11	0.91	0.89	1.26
29	OGE Energy	0.92	1.02	1.03	0.87	1.24	1.27	1.00	0.84	0.61	0.74
30	Otter Tail Corp.	1.02	1.83	1.98	2.13	0.48	0.92	0.89	0.74	0.94	0.82
31	Pinnacle West Capital	0.93	0.70	0.73	0.89	0.91	1.00	0.83	0.93	0.98	1.04
32	TXNM Energy	0.69	0.51	0.55	0.63	0.72	0.77	0.66	0.77	0.76	0.58
33	Portland General	0.81	0.65	0.51	0.86	0.78	0.93	0.92	0.78	0.83	0.76
34	PPL Corp.	0.97	0.90	1.06	1.05	0.90	0.94	0.84	0.78	1.08	1.18
35	Public Serv. Enterprise	1.09	0.95	0.92	1.05	1.13	0.97	0.68	0.98	1.31	1.64
36	SCANA Corp.	0.86	N/A	N/A	N/A		N/A	0.78	0.84	0.83	0.98
37	Sempra Energy	0.79	0.59	0.61	0.92	0.77	0.81	0.68	0.77	0.88	0.90
38	Southern Co.	0.90	0.94	0.88	0.97	0.99	0.90	0.85	0.86	0.88	0.93
39	Vectren Corp.	1.00	N/A	N/A	N/A		N/A	0.88	1.06	1.11	0.93
40	WEC Energy Group	0.98	1.01	0.95	1.09	0.97	0.93	1.03	1.36	0.96	0.62
41	Westar Energy	0.72	N/A	N/A	N/A		N/A	0.80	0.70	0.76	0.61
42	Xcel Energy Inc.	0.75	0.66	0.75	0.93	0.66	0.74	0.75	0.68	0.83	0.79
43	Average	0.89	0.87	0.85	0.93	0.84	0.86	0.88	0.88	0.94	0.91
44	Median	0.83	0.82	0.82	0.87	0.81	0.83	0.86	0.84	0.89	0.91

Sources:

[1] Data for years 2019 and prior were retrieved from the Value Line Investment Survey Investment Analyzer Software, downloaded on June 18, 2021. Data for the years 2020 - 2024 was retrieved from Value Line Investment Surveys.

[2] The Value Line Investment Survey, March 7, April 18, and May 9, 2025.

Notes:

[c] Based on the projected Cash Flow per share and Capital Spending per share published in The Value Line Investment Survey, March 7, April 18, and May 9, 2025.

Valley Energy, Inc. / Citizens' Electric Company of Lewisburg, PA / Wellsboro Electric Company

Natural Gas Utilities
(Valuation Metrics)

Price to Earnings (P/E) Ratio [1]

Line	Company	19-Year Average	2024 [2]	2023	2022	2021	3-Year Averages 2018-2020	2015-2017	2012-2014	2009-2011	2006-2008
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Atmos Energy	17.60	20.90	16.80	19.30	18.80	22.40	20.10	15.97	13.37	14.34
2	Chesapeake Utilities	19.50	21.60	21.60	25.80	25.60	23.07	23.07	16.03	13.53	16.25
3	New Jersey Resources	17.02	14.90	14.90	17.00	17.50	19.20	20.10	14.83	15.57	16.68
4	NiSource Inc.	21.97	20.10	16.90	19.60	18.00	19.77	41.63	19.83	16.33	16.69
5	Northwest Nat. Gas	20.24	13.70	15.40	19.60	19.50	27.50	25.30	20.40	17.07	16.88
6	ONE Gas Inc.	20.55	17.30	16.00	19.90	18.90	23.37	22.00	17.80	N/A	N/A
7	Southwest Gas	17.95	19.80	23.00	NMF	14.30	19.57	21.07	16.23	13.97	17.85
8	Spire Inc.	18.28	17.40	14.50	17.50	13.60	30.20	18.63	18.53	13.37	14.03
9	UGI Corp.	15.03	10.20	8.40	14.10	13.90	18.33	19.27	15.87	12.07	14.12
10	Average	18.50	17.32	16.39	19.10	17.79	22.60	23.46	17.28	14.41	15.85
11	Median	17.40	17.40	16.00	19.45	18.00	22.40	21.07	16.23	13.75	16.46

Market Price to Cash Flow (MP/CF) Ratio [1]

Line	Company	19-Year Average	2024 [2]	2023	2022	2021	3-Year Averages 2018-2020	2015-2017	2012-2014	2009-2011	2006-2008
		(1)	(2)	(3)	(4)	(5)	(21)	(22)	(23)	(24)	(25)
12	Atmos Energy	9.46	11.93	11.27	11.87	10.99	12.83	10.88	7.85	6.26	6.76
13	Chesapeake Utilities	10.91	14.44	15.77	14.21	14.20	12.91	12.00	8.28	7.73	8.62
14	New Jersey Resources	11.83	9.95	11.22	11.55	11.56	12.84	13.37	10.84	11.79	11.31
15	NiSource Inc.	7.85	7.98	7.13	8.13	7.89	8.52	10.35	9.03	5.32	6.14
16	Northwest Nat. Gas	11.89	6.96	7.56	8.76	8.57	11.66	26.92	8.98	8.76	8.37
17	ONE Gas Inc.	10.06	7.87	7.73	9.91	9.32	11.82	10.73	8.16	N/A	N/A
18	Southwest Gas	7.26	7.77	7.35	19.83	6.87	8.43	7.69	5.95	4.78	5.20
19	Spire Inc.	9.47	7.29	7.53	8.34	7.55	11.63	9.73	11.53	8.26	8.62
20	UGI Corp.	7.70	4.67	5.84	7.20	9.56	9.78	9.19	6.78	6.42	7.50
21	Average	9.50	8.76	9.04	11.09	9.61	11.16	12.32	8.60	7.42	7.82
22	Median	8.37	7.87	7.56	9.91	9.32	11.66	10.73	8.28	7.07	7.94

Market Price to Book Value (MP/BV) Ratio [1]

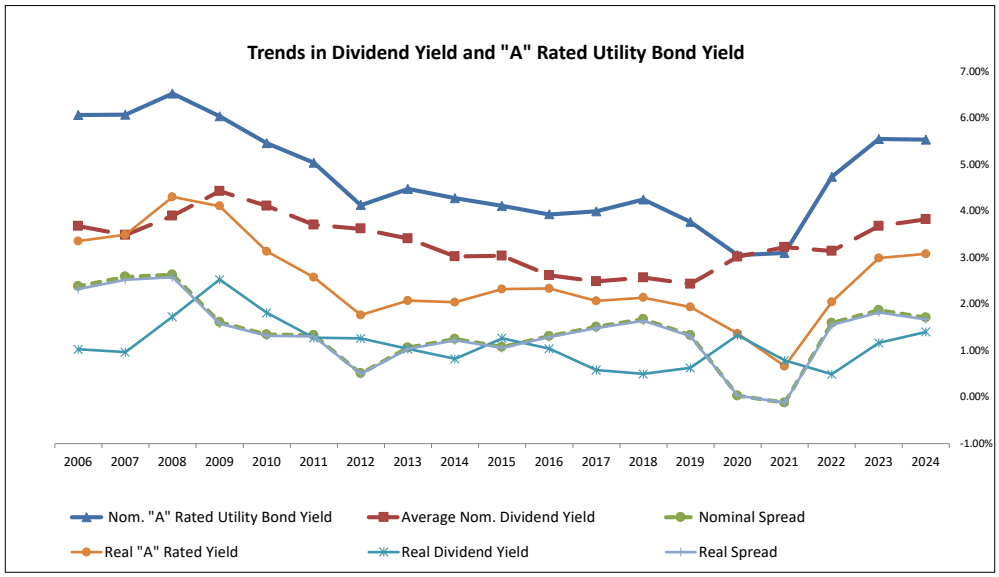
Line	Company	19-Year Average	2024 [2]	2023	2022	2021	3-Year Averages 2018-2020	2015-2017	2012-2014	2009-2011	2006-2008
		(1)	(2)	(3)	(4)	(5)	(21)	(22)	(23)	(24)	(25)
23	Atmos Energy	1.59	1.68	1.55	1.65	1.59	2.03	2.00	1.41	1.18	1.31
24	Chesapeake Utilities	2.06	1.91	1.93	2.69	2.77	2.49	2.32	1.87	1.46	1.78
25	New Jersey Resources	2.26	2.06	2.32	2.35	2.26	2.43	2.50	2.17	2.19	2.03
26	NiSource Inc.	1.54	1.40	1.14	2.15	1.86	1.99	1.92	1.63	0.92	1.10
27	Northwest Nat. Gas	1.78	1.15	1.29	1.51	1.45	2.23	1.99	1.62	1.73	1.90
28	ONE Gas Inc.	1.63	1.32	1.43	1.73	1.57	2.01	1.61	1.07	N/A	N/A
29	Southwest Gas	1.53	1.34	1.28	1.62	1.32	1.70	1.93	1.60	1.21	1.38
30	Spire Inc.	1.53	1.25	1.29	1.43	1.47	1.69	1.57	1.40	1.51	1.69
31	UGI Corp.	1.94	1.30	1.59	1.39	1.64	2.36	2.44	1.70	1.65	2.13
32	Average	1.76	1.49	1.53	1.83	1.77	2.10	2.03	1.61	1.48	1.66
33	Median	1.67	1.34	1.43	1.65	1.59	2.03	1.99	1.62	1.49	1.73

Sources:
The current year P/E ratio is based on the forward P/E (price over expected earnings per share). All historical year P/E ratios are based on annual average share price over achieved earnings per share.
[1] Data for years 2019 and prior were retrieved from the Value Line Investment Survey Investment Analyzer Software, downloaded on June 18, 2021. Data for the years 2020 - 2024 was retrieved from Value Line Investment Surveys.
[2] The Value Line Investment Survey, May 23, 2025.
Notes:
[a] Based on the average of the high and low price for year and the projected Cash Flow per share, published in The Value Line Investment Survey.
[b] Based on the average of the high and low price for the year and the projected Book Value per share, published in The Value Line Investment Survey.

Valley Energy, Inc. / Citizens' Electric Company of Lewisburg, PA / Wellsboro Electric Company

Natural Gas Utilities
(Valuation Metrics)

Line	Company	Dividend Yield[1] 18-Year Average (1)	2024 [2/a] (2)	2023 (3)	2022 (4)	2021 (5)	3-Year Averages 2018-2020 (6)	2015-2017 (7)	2012-2014 (8)	2009-2011 (9)	2006-2008 (10)
1	Atmos Energy	3.30%	2.45%	2.62%	2.46%	2.63%	2.17%	2.51%	3.59%	4.74%	4.53%
2	Chesapeake Utilities	2.62%	2.12%	2.08%	1.61%	1.50%	1.77%	1.93%	2.85%	3.79%	3.83%
3	New Jersey Resources	3.25%	3.75%	3.29%	3.25%	3.50%	2.86%	2.90%	3.53%	3.49%	3.19%
4	NiSource Inc.	3.92%	3.34%	3.85%	3.33%	3.60%	3.12%	3.03%	3.28%	5.94%	4.73%
5	Northwest Nat. Gas	3.69%	4.93%	4.40%	3.86%	3.90%	3.06%	3.43%	4.06%	3.73%	3.37%
6	ONE Gas Inc.	2.82%	3.87%	3.72%	3.08%	3.21%	2.47%	2.47%	2.28%	N/A	N/A
7	Southwest Gas	3.03%	3.60%	4.07%	3.20%	3.65%	2.87%	2.65%	2.72%	3.32%	2.78%
8	Spire Inc.	3.86%	4.65%	4.44%	3.89%	3.79%	3.15%	3.24%	3.95%	4.31%	4.24%
9	UGI Corp.	3.14%	5.75%	4.64%	3.61%	3.25%	2.60%	2.29%	3.10%	3.34%	2.83%
10	**Average**	**3.34%**	**3.83%**	**3.68%**	**3.14%**	**3.23%**	**2.67%**	**2.72%**	**3.26%**	**4.08%**	**3.69%**
11	Median	3.42%	3.75%	3.85%	3.25%	3.50%	2.86%	2.65%	3.28%	3.76%	3.60%
12	20-Yr Treasury Yields[3]	3.32%	4.50%	4.25%	3.30%	1.98%	2.26%	2.47%	2.91%	3.92%	4.75%
13	20-Yr TIPS[3]	1.12%	2.06%	1.73%	0.64%	-0.43%	0.41%	0.73%	0.61%	1.71%	2.28%
14	Implied Inflation[b]	2.17%	2.39%	2.48%	2.64%	2.42%	1.84%	1.73%	2.29%	2.17%	2.42%
15	**Real Dividend Yield[c]**	**1.14%**	**1.40%**	**1.17%**	**0.49%**	**0.79%**	**0.82%**	**0.97%**	**0.95%**	**1.87%**	**1.24%**
	Utility										
16	**Nominal "A" Rated Yield[4]**	**4.74%**	**5.54%**	**5.55%**	**4.74%**	**3.10%**	**3.69%**	**4.01%**	**4.29%**	**5.51%**	**6.22%**
17	**Real "A" Rated Yield**	**2.52%**	**3.08%**	**2.99%**	**2.05%**	**0.67%**	**1.82%**	**2.24%**	**1.96%**	**3.27%**	**3.72%**
	Spreads (Utility Bond - Stock)										
18	**Nominal[d]**	**1.41%**	**1.71%**	**1.87%**	**1.60%**	**-0.12%**	**1.02%**	**1.30%**	**1.03%**	**1.43%**	**2.54%**
19	**Real[e]**	**1.38%**	**1.67%**	**1.82%**	**1.56%**	**-0.12%**	**1.00%**	**1.28%**	**1.01%**	**1.40%**	**2.48%**
	Spreads (Treasury Bond - Stock)										
20	**Nominal[f]**	**-0.02%**	**0.67%**	**0.57%**	**0.16%**	**-1.25%**	**-0.42%**	**-0.24%**	**-0.35%**	**-0.16%**	**1.07%**
21	**Real[g]**	**-0.02%**	**0.66%**	**0.56%**	**0.15%**	**-1.22%**	**-0.41%**	**-0.24%**	**-0.34%**	**-0.16%**	**1.04%**



Sources:
[1] Data for years 2019 and prior were retrieved from the Value Line Investment Survey Investment Analyzer Software, downloaded on June 18, 2021.
Data for the years 2020 - 2024 was retrieved from Value Line Investment Surveys.
[2] The Value Line Investment Survey, May 23, 2025.
[3] St. Louis Federal Reserve: Economic Research, http://research.stlouisfed.org.
[4] Mergent Bond Record, through December 31, 2024.

Notes:
[a] Based on the average of the high and low price for the year and the projected Dividends Declared per share published in the Value Line Investment Survey.
[b] Line 16 = (1 + Line 14) / (1 + Line 15) - 1.
[c] Line 17 = (1 + Line 12) / (1 +Line 16) - 1.
[d] The spread being measured here is the nominal A-rated utility bond yield over the average nominal utility dividend yield; (Line 18 - Line 12).
[e] The spread being measured here is the real A-rated utility bond yield over the average real utility dividend yield; Line 19 - Line 17)
[f] The spread being measured here is the nominal 20-Year Treasury yield over the average nominal utility dividend yield; (Line 14 - Line 12).
[g] The spread being measured here is the real 20-Year TIPS yield over the average real utility dividend yield; Line 15 - Line 17)

Valley Energy, Inc. / Citizens' Electric Company of Lewisburg, PA / Wellsboro Electric Company

Natural Gas Utilities
(Valuation Metrics)

		Dividend per Share[1]											
		19-Year					3-Year Averages					2018	2017
Line	Company	Average	2024 [2]	2023	2022	2021	2018-2020	2015-2017	2012-2014	2009-2011	2006-2008	CAGR	CAGR
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
1	Atmos Energy	1.84	3.22	2.96	2.72	2.50	2.11	1.68	1.42	1.34	1.28	2.08%	2.15%
2	Chesapeake Utilities	1.30	2.46	2.25	2.03	1.84	1.54	1.19	1.01	0.87	0.79	2.89%	3.02%
3	New Jersey Resources	0.98	1.71	1.56	1.45	1.36	1.19	0.98	0.81	0.67	0.51	3.97%	4.59%
4	NiSource Inc.	0.89	1.06	1.00	0.94	0.88	0.81	0.72	0.98	0.92	0.92	-0.82%	-1.69%
5	Northwest Nat. Gas	1.78	1.95	1.94	1.93	1.92	1.90	1.87	1.82	1.68	1.45	1.36%	1.68%
6	ONE Gas Inc.	1.92	2.64	2.60	2.48	2.32	2.00	1.43	0.84	N/A	N/A	3.58%	4.30%
7	Southwest Gas	1.65	2.48	2.48	2.48	2.38	2.18	1.80	1.32	1.00	0.86	4.48%	5.35%
8	Spire Inc.	2.02	3.02	2.88	2.74	2.60	2.37	1.97	1.71	1.57	1.45	2.20%	2.34%
9	UGI Corp.	0.92	1.50	1.47	1.41	1.35	1.16	0.93	0.75	0.60	0.48	3.80%	4.41%
10	**Average**	**1.44**	**2.23**	**2.13**	**2.02**	**1.91**	**1.70**	**1.40**	**1.18**	**1.08**	**0.97**	**2.62%**	**2.91%**
11	**Industry Average Growth**	**4.94%**	**4.70%**	**5.28%**	**6.01%**	**5.54%**	**6.64%**	**6.41%**	**3.16%**	**4.06%**	**3.28%**		

Sources:

[1] Data for years 2019 and prior were retrieved from the Value Line Investment Survey Investment Analyzer Software, downloaded on June 18, 2021.
Data for the years 2020 - 2024 was retrieved from Value Line Investment Surveys.

[2] The Value Line Investment Survey, May 23, 2025.

Valley Energy, Inc. / Citizens' Electric Company of Lewisburg, PA / Wellsboro Electric Company

Natural Gas Utilities
(Valuation Metrics)

			Earnings per Share[1]								
		19-Year					3-Year Averages				
Line	Company	Average	2024 [2]	2023	2022	2021	2018-2020	2015-2017	2012-2014	2009-2011	2006-2008
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Atmos Energy	3.51	6.83	6.10	5.60	5.12	4.36	3.36	2.52	2.13	1.98
2	Chesapeake Utilities	2.89	5.26	4.73	4.97	4.70	3.79	2.74	2.24	1.72	1.28
3	New Jersey Resources	1.78	2.95	2.70	2.50	2.16	2.25	1.71	1.60	1.24	1.02
4	NiSource Inc.	1.23	1.75	1.60	1.47	1.35	1.31	0.67	1.54	0.98	1.21
5	Northwest Nat. Gas	2.17	2.33	2.59	2.54	2.50	2.27	0.71	2.21	2.65	2.56
6	ONE Gas Inc.	3.31	3.91	4.14	4.08	3.85	3.48	2.64	2.07	N/A	N/A
7	Southwest Gas	2.85	2.76	2.13	3.10	3.80	3.92	3.24	2.99	2.21	1.77
8	Spire Inc.	3.09	4.19	3.85	3.95	4.96	3.10	3.28	2.39	2.74	2.44
9	UGI Corp.	2.03	3.06	2.84	2.90	2.96	2.56	2.12	1.56	1.51	1.20
10	**Average**	**2.47**	**3.67**	**3.41**	**3.46**	**3.49**	**3.00**	**2.27**	**2.12**	**1.90**	**1.68**
11	**Industry Average Growth**	**5.25%**	**7.69%**	**-1.38%**	**-0.92%**	**18.27%**	**14.40%**	**-2.65%**	**5.77%**	**3.58%**	**3.74%**

Sources:

[1] Data for years 2019 and prior were retrieved from the Value Line Investment Survey Investment Analyzer Software, downloaded on June 18, 2021. Data for the years 2020 - 2024 was retrieved from Value Line Investment Surveys.

[2] The Value Line Investment Survey, May 23, 2025.

Valley Energy, Inc. / Citizens' Electric Company of Lewisburg, PA / Wellsboro Electric Company

Natural Gas Utilities
(Valuation Metrics)

Line	Company	Cash Flow / Capital Spending[1] 2019 (1)	2020 (2)	2021 (3)	2022 (4)	2023 (5)	2024 (6)	2025[2] (7)	3 - 5 yr[2] Projection (8)
1	Atmos Energy	0.53x	0.53x	0.53x	0.54x	0.54x	0.55x	0.52x	0.68x
2	Chesapeake Utilities	0.66x	0.64x	0.82x	1.23x	0.84x	0.61x	0.63x	0.92x
3	New Jersey Resources	1.41x	0.65x	0.72x	0.59x	0.68x	1.03x	0.93x	0.93x
4	NiSource Inc.	0.66x	0.65x	0.69x	0.55x	0.43x	0.54x	0.75x	0.76x
5	Northwest Nat. Gas	0.77x	0.75x	0.61x	0.60x	0.68x	0.63x	0.68x	0.65x
6	ONE Gas Inc.	0.78x	0.88x	0.86x	0.74x	0.83x	0.81x	0.81x	0.99x
7	Southwest Gas	0.62x	0.53x	0.61x	0.31x	0.84x	0.76x	0.81x	0.90x
8	Spire Inc.	0.65x	0.65x	0.70x	0.80x	0.71x	0.64x	0.65x	0.85x
9	UGI Corp.	1.33x	1.54x	1.66x	1.42x	1.33x	1.24x	1.56x	1.56x
10	Average	0.82x	0.76x	0.80x	0.75x	0.76x	0.76x	0.81x	0.91x
11	Median	0.66x	0.65x	0.70x	0.60x	0.71x	0.64x	0.75x	0.90x

Sources:
[1] The Value Line Investment Survey, various report dates.
[2] The Value Line Investment Survey, May 23, 2025.
Notes:
Based on the projected Cash Flow per share and Capital Spending per share.

Valley Energy, Inc. / Citizens' Electric Company of Lewisburg, PA / Wellsboro Electric Company

Natural Gas Utilities
(Valuation Metrics)

Percent Dividends to Book Value [1]

Line	Company	19-Year Average	2024 [2b]	2023	2022	2021	3-Year Averages 2018-2020	2015-2017	2012-2014	2009-2011	2006-2008
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Atmos Energy	4.94%	4.11%	4.04%	4.07%	4.19%	4.38%	4.97%	5.00%	5.53%	5.94%
2	Chesapeake Utilities	5.04%	4.05%	4.01%	4.32%	4.15%	4.38%	4.45%	5.27%	5.50%	6.77%
3	New Jersey Resources	7.27%	7.73%	7.65%	7.63%	7.92%	6.77%	7.21%	7.64%	7.63%	6.45%
4	NiSource Inc.	5.56%	4.67%	4.40%	7.15%	6.69%	6.20%	5.81%	5.23%	5.22%	5.11%
5	Northwest Nat. Gas	6.40%	5.66%	5.69%	5.83%	5.66%	6.81%	6.70%	6.58%	6.48%	6.37%
6	ONE Gas Inc.	4.53%	5.09%	5.32%	5.31%	5.04%	4.94%	3.92%	2.44%	N/A	N/A
7	Southwest Gas	4.52%	4.83%	5.20%	5.17%	4.80%	4.85%	5.07%	4.35%	3.92%	3.79%
8	Spire Inc.	5.86%	5.83%	5.73%	5.58%	5.56%	5.31%	5.07%	5.52%	6.46%	7.16%
9	UGI Corp.	5.78%	7.46%	7.35%	5.02%	5.34%	5.92%	5.55%	5.19%	5.51%	6.03%
10	Average	5.60%	5.49%	5.49%	5.57%	5.48%	5.51%	5.42%	5.25%	5.78%	5.95%
11	Median	5.32%	5.09%	5.32%	5.31%	5.34%	5.31%	5.07%	5.23%	5.52%	6.20%

Dividends to Earnings Ratio [1]

Line	Company	19-Year Average	2024 [2b]	2023	2022	2021	3-Year Averages 2018-2020	2015-2017	2012-2014	2009-2011	2006-2008
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
12	Atmos Energy	0.55	0.47	0.49	0.49	0.49	0.49	0.50	0.57	0.63	0.65
13	Chesapeake Utilities	0.47	0.47	0.48	0.41	0.39	0.41	0.43	0.45	0.51	0.62
14	New Jersey Resources	0.55	0.58	0.58	0.58	0.63	0.54	0.58	0.52	0.54	0.53
15	NiSource Inc.	0.80	0.61	0.63	0.64	0.65	0.62	1.25	0.64	0.95	0.77
16	Northwest Nat. Gas	0.66	0.84	0.75	0.76	0.77	0.84	0.29	0.83	0.64	0.57
17	ONE Gas Inc.	0.57	0.68	0.63	0.61	0.60	0.57	0.54	0.41	N/A	N/A
18	Southwest Gas	0.58	0.90	1.16	0.80	0.63	0.56	0.56	0.44	0.46	0.50
19	Spire Inc.	0.69	0.72	0.75	0.69	0.52	0.97	0.60	0.73	0.58	0.59
20	UGI Corp.	0.45	0.49	0.52	0.49	0.46	0.46	0.44	0.49	0.40	0.40
21	Average	0.59	0.64	0.66	0.61	0.57	0.61	0.58	0.57	0.59	0.58
22	Median	0.58	0.61	0.63	0.61	0.60	0.56	0.54	0.52	0.56	0.58

Cash Flow to Capital Spending Ratio [1]

Line	Company	19-Year Average	2024 [2b]	2023	2022	2021	3-Year Averages 2018-2020	2015-2017	2012-2014	2009-2011	2006-2008
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
23	Atmos Energy	0.64	0.58	0.53	0.54	0.58	0.53	0.60	0.60	0.74	0.86
24	Chesapeake Utilities	0.75	0.52	0.81	1.23	0.81	0.60	0.51	0.72	1.12	0.70
25	New Jersey Resources	1.18	0.87	0.82	0.59	0.62	0.69	0.66	1.58	1.60	1.97
26	NiSource Inc.	0.74	0.71	0.61	0.55	0.68	0.62	0.51	0.59	0.97	1.14
27	Northwest Nat. Gas	0.89	0.65	0.67	0.60	0.68	0.69	0.76	1.05	0.97	1.30
28	ONE Gas Inc.	0.83	0.74	0.77	0.74	0.86	0.85	0.88	0.79	N/A	N/A
29	Southwest Gas	0.81	0.67	0.68	0.31	0.86	0.59	0.78	0.98	1.16	0.78
30	Spire Inc.	1.01	0.60	0.69	0.80	0.75	0.54	0.87	0.90	1.69	1.45
31	UGI Corp.	1.45	1.52	1.18	1.42	1.32	1.48	1.37	1.46	1.39	1.68
32	Average	0.94	0.76	0.75	0.75	0.80	0.73	0.77	0.96	1.20	1.23
33	Median	0.84	0.67	0.69	0.60	0.75	0.62	0.76	0.90	1.14	1.22

Sources:
[1] Data for years 2019 and prior were retrieved from the Value Line Investment Survey Investment Analyzer Software, downloaded on June 18, 2021.
Data for the years 2020 - 2024 was retrieved from Value Line Investment Surveys.
[2] The Value Line Investment Survey, May 23, 2025.
Notes:
[a] Based on the projected Dividends Declared per share and Book Value per share, published in The Value Line Investment Survey.
[b] Based on the projected Dividends Declared per share and Earnings per share, published in The Value Line Investment Survey.
[c] Based on the projected Cash Flow per share and Capital Spending per share, published in The Value Line Investment Survey.

Valley Energy, Inc. / Citizens' Electric Company of Lewisburg, PA / Wellsboro Electric Company

Proxy Group

Line	Company	Credit Ratings[1]		Common Equity Ratios	
		S&P	Moody's	MI[1]	Value Line[2]
		(1)	(2)	(3)	(4)
1	Atmos Energy Corporation	A-	A2	59.9%	62.1%
2	New Jersey Resources Corporation	N/A	A1	38.4%	41.8%
3	NiSource Inc.	BBB+	Baa2	35.2%	40.3%
4	Northwest Natural Holding Company	A-	N/A	41.4%	47.4%
5	ONE Gas, Inc.	A-	A3	48.1%	56.2%
6	Southwest Gas Holdings, Inc.	BBB-	Baa2	39.5%	41.8%
7	Spire Inc.	BBB+	Baa2	37.4%	41.3%
8	Alliant Energy Corporation	BBB+	Baa2	39.7%	45.2%
9	Ameren Corporation	BBB+	Baa1	39.0%	43.8%
10	American Electric Power Company, Inc.	BBB+	Baa2	36.9%	42.0%
11	Duke Energy Corporation	BBB+	Baa2	35.9%	38.8%
12	Edison International	BBB	Baa2	25.1%	28.7%
13	Entergy Corporation	BBB+	Baa2	33.7%	38.6%
14	Evergy, Inc.	BBB+	Baa2	41.1%	48.0%
15	IDACORP, Inc.	BBB	Baa2	52.0%	51.2%
16	NorthWestern Corporation	BBB	Baa2	48.0%	50.9%
17	OGE Energy Corp.	BBB+	Baa1	45.5%	49.6%
18	Pinnacle West Capital Corporation	BBB+	Baa2	37.7%	45.0%
19	Portland General Electric Company	BBB+	A3	42.5%	44.2%
20	Southern Company	A-	Baa1	32.3%	37.6%
21	Xcel Energy Inc.	BBB+	Baa1	39.2%	41.4%
22	**Average**	**BBB+**	**Baa1**	**40.4%**	**44.6%**
23	**Median**			**39.2%**	**43.8%**
24	**Citizens/Valley/Wellsboro[3,4]**	**N/A**	**N/A**		**48.94%**

Sources:

Note: If credit rating/common equity ratio unavailable for utility, subsidiary data used.

[1] S&P Global Market Intelligence, Downloaded on May 30, 2025.

[2] *The Value Line Investment Survey* , March 7, April 18, May, 9, and May 23, 2025.

[3] No rating from S&P or Moody's.

[4] Direct Testimony of Dylan W. D'Ascendis and Ryan M. Kucan, page 4.

Valley Energy, Inc. / Citizens' Electric Company of Lewisburg, PA / Wellsboro Electric Company

Consensus Analysts' Growth Rates

Line	Company	Zacks[1] (1)	S&P[2] (2)	I/B/E/S[3] (3)	Average of Growth Rates (4)
1	Atmos Energy Corporation	7.19%	7.28%	7.30%	7.26%
2	New Jersey Resources Corporation	N/A	7.90%	N/A	7.90%
3	NiSource Inc.	7.88%	7.83%	7.70%	7.80%
4	Northwest Natural Holding Company	N/A	5.75%	N/A	5.75%
5	ONE Gas, Inc.	5.56%	5.84%	N/A	5.70%
6	Southwest Gas Holdings, Inc.	9.87%	9.55%	13.70%	11.04%
7	Spire Inc.	6.54%	7.54%	N/A	7.04%
8	Alliant Energy Corporation	6.59%	6.54%	6.45%	6.53%
9	Ameren Corporation	6.95%	6.95%	6.80%	6.90%
10	American Electric Power Company, Inc.	6.43%	6.80%	6.37%	6.53%
11	Duke Energy Corporation	6.33%	6.38%	6.55%	6.42%
12	Edison International	7.01%	8.57%	9.97%	8.52%
13	Entergy Corporation	9.46%	9.12%	9.63%	9.40%
14	Evergy, Inc.	5.70%	5.70%	5.60%	5.67%
15	IDACORP, Inc.	8.12%	8.09%	7.35%	7.85%
16	NorthWestern Corporation	6.87%	5.80%	6.45%	6.37%
17	OGE Energy Corp.	6.32%	6.53%	5.60%	6.15%
18	Pinnacle West Capital Corporation	2.12%	4.76%	2.20%	3.03%
19	Portland General Electric Company	3.44%	4.76%	3.57%	3.92%
20	Southern Company	6.55%	6.29%	7.25%	6.70%
21	Xcel Energy Inc.	7.52%	7.73%	8.40%	7.88%
22	**Average**	**6.66%**	**6.94%**	**7.11%**	**6.87%**
23	**Median**	**6.59%**	**6.80%**	**6.80%**	**6.70%**

Sources:
[1] Zacks, http://www.zacks.com/, downloaded on May 30, 2025.
[2] S&P Global Market Intelligence, https://platform.mi.spglobal.com, downloaded on May 30, 2025.
[3] LSEG Workspace, https://www.lseg.com/en/data-analytics/products/workspace, downloaded on May 30, 2025.

Valley Energy, Inc. / Citizens' Electric Company of Lewisburg, PA / Wellsboro Electric Company

Constant Growth DCF Model
(Consensus Analysts' Growth Rates)

Line	Company	13-Week AVG Stock Price[1] (1)	Analysts' Growth[2] (2)	Annualized Dividend[3] (3)	Adjusted Yield (4)	Constant Growth DCF (5)
1	Atmos Energy Corporation	$153.92	7.26%	$3.48	2.42%	9.68%
2	New Jersey Resources Corporation	$48.02	7.90%	$1.80	4.04%	11.94%
3	NiSource Inc.	$39.00	7.80%	$1.12	3.10%	10.90%
4	Northwest Natural Holding Company	$41.89	5.75%	$1.96	4.95%	10.70%
5	ONE Gas, Inc.	$75.22	5.70%	$2.68	3.77%	9.47%
6	Southwest Gas Holdings, Inc.	$72.39	11.04%	$2.48	3.80%	14.84%
7	Spire Inc.	$75.70	7.04%	$3.14	4.44%	11.48%
8	Alliant Energy Corporation	$61.91	6.53%	$1.92	3.30%	9.83%
9	Ameren Corporation	$97.85	6.90%	$2.84	3.10%	10.00%
10	American Electric Power Company, Inc.	$104.80	6.53%	$3.72	3.78%	10.31%
11	Duke Energy Corporation	$118.61	6.42%	$4.18	3.75%	10.17%
12	Edison International	$56.52	8.52%	$3.31	6.36%	14.87%
13	Entergy Corporation	$82.67	9.40%	$2.40	3.18%	12.58%
14	Evergy, Inc.	$66.95	5.67%	$2.67	4.21%	9.88%
15	IDACORP, Inc.	$115.71	7.85%	$3.44	3.21%	11.06%
16	NorthWestern Corporation	$56.42	6.37%	$2.64	4.98%	11.35%
17	OGE Energy Corp.	$44.53	6.15%	$1.69	4.02%	10.17%
18	Pinnacle West Capital Corporation	$92.32	3.03%	$3.58	4.00%	7.02%
19	Portland General Electric Company	$42.93	3.92%	$2.00	4.84%	8.76%
20	Southern Company	$89.84	6.70%	$2.96	3.52%	10.21%
21	Xcel Energy Inc.	$69.72	7.88%	$2.28	3.53%	11.41%
22	**Average**	**$76.52**	**6.87%**	**$2.68**	**3.92%**	**10.79%**
23	**Median**	**$72.39**	**6.70%**	**$2.67**	**3.78%**	**10.31%**

Sources:
[1] S&P Global Market Intelligence, Downloaded on May 30, 2025.
[2] Exhibit CCW-3
[3] *The Value Line Investment Survey* , March 7, April 18, May, 9, and May 23, 2025.

Valley Energy, Inc. / Citizens' Electric Company of Lewisburg, PA / Wellsboro Electric Company

Payout Ratios

Line	Company	Dividends Per Share		Earnings Per Share		Payout Ratio	
		2023	Projected	2023	Projected	2023	Projected
		(1)	(2)	(3)	(4)	(5)	(6)
1	Atmos Energy Corporation	$2.96	$4.45	$6.10	$9.35	48.52%	47.59%
2	New Jersey Resources Corporation	$1.56	$2.20	$2.71	$3.90	57.56%	56.41%
3	NiSource Inc.	$1.00	$1.44	$1.60	$2.55	62.50%	56.47%
4	Northwest Natural Holding Company	$1.94	$2.00	$2.59	$3.45	74.90%	57.97%
5	ONE Gas, Inc.	$2.60	$2.90	$4.14	$5.25	62.80%	55.24%
6	Southwest Gas Holdings, Inc.	$2.48	$3.00	$2.13	$5.00	116.43%	60.00%
7	Spire Inc.	$2.88	$3.70	$3.85	$5.25	74.81%	70.48%
8	Alliant Energy Corporation	$1.81	$2.43	$2.78	$4.25	65.11%	57.18%
9	Ameren Corporation	$2.52	$3.57	$4.37	$6.50	57.67%	54.92%
10	American Electric Power Company, Inc.	$3.37	$4.31	$5.24	$7.50	64.31%	57.47%
11	Duke Energy Corporation	$4.06	$5.00	$5.56	$8.00	73.02%	62.50%
12	Edison International	$2.99	$4.25	$4.76	$7.00	62.82%	60.71%
13	Entergy Corporation	$2.17	$3.00	$5.55	$4.20	39.10%	71.43%
14	Evergy, Inc.	$2.48	$3.25	$3.17	$5.00	78.23%	65.00%
15	IDACORP, Inc.	$3.20	$4.20	$5.14	$7.10	62.26%	59.15%
16	NorthWestern Corporation	$2.56	$2.80	$3.22	$4.30	79.50%	65.12%
17	OGE Energy Corp.	$1.66	$1.79	$2.07	$2.95	80.19%	60.68%
18	Pinnacle West Capital Corporation	$3.49	$3.85	$4.41	$6.25	79.14%	61.60%
19	Portland General Electric Company	$1.88	$2.60	$2.38	$4.00	78.99%	65.00%
20	Southern Company	$2.78	$3.10	$3.64	$5.60	76.37%	55.36%
21	Xcel Energy Inc.	$2.08	$3.00	$3.35	$5.00	62.09%	60.00%
22	**Average**	**$2.50**	**$3.18**	**$3.75**	**$5.35**	**69.35%**	**60.01%**

Source:
The Value Line Investment Survey , March 7, April 18, May, 9, and May 23, 2025.

Valley Energy, Inc. / Citizens' Electric Company of Lewisburg, PA / Wellsboro Electric Company

Sustainable Growth Rate

Line	Company	3 to 5 Year Projections										Sustainable Growth Rate
		Dividends Per Share (1)	Earnings Per Share (2)	Book Value Per Share (3)	Book Value Growth (4)	ROE (5)	Adjustment Factor (6)	Adjusted ROE (7)	Payout Ratio (8)	Retention Rate (9)	Internal Growth Rate (10)	(11)
1	Atmos Energy Corporation	$4.45	$9.35	$97.30	4.86%	9.61%	1.02	9.84%	47.59%	52.41%	5.16%	9.27%
2	New Jersey Resources Corporation	$2.20	$3.90	$27.65	5.20%	14.10%	1.03	14.46%	56.41%	43.59%	6.30%	7.97%
3	NiSource Inc.	$1.44	$2.55	$25.70	6.72%	9.92%	1.03	10.24%	56.47%	43.53%	4.46%	7.81%
4	Northwest Natural Holding Company	$2.00	$3.45	$40.40	2.86%	8.54%	1.01	8.66%	57.97%	42.03%	3.64%	4.74%
5	ONE Gas, Inc.	$2.90	$5.25	$56.60	2.46%	9.28%	1.01	9.39%	55.24%	44.76%	4.20%	6.15%
6	Southwest Gas Holdings, Inc.	$3.00	$5.00	$58.65	4.04%	8.53%	1.02	8.69%	60.00%	40.00%	3.48%	3.92%
7	Spire Inc.	$3.70	$5.25	$57.80	2.35%	9.08%	1.01	9.19%	70.48%	29.52%	2.71%	5.33%
8	Alliant Energy Corporation	$2.43	$4.25	$31.90	3.17%	13.32%	1.02	13.53%	57.18%	42.82%	5.79%	5.87%
9	Ameren Corporation	$3.57	$6.50	$52.65	4.57%	12.35%	1.02	12.62%	54.92%	45.08%	5.69%	7.25%
10	American Electric Power Company, Inc.	$4.31	$7.50	$60.90	3.88%	12.32%	1.02	12.55%	57.47%	42.53%	5.34%	6.20%
11	Duke Energy Corporation	$5.00	$8.00	$76.50	3.80%	10.46%	1.02	10.65%	62.50%	37.50%	3.99%	4.18%
12	Edison International	$4.25	$7.00	$50.00	5.62%	14.00%	1.03	14.38%	60.71%	39.29%	5.65%	5.92%
13	Entergy Corporation	$3.00	$4.20	$43.45	3.99%	9.67%	1.02	9.86%	71.43%	28.57%	2.82%	4.64%
14	Evergy, Inc.	$3.25	$5.00	$47.50	2.05%	10.53%	1.01	10.63%	65.00%	35.00%	3.72%	3.73%
15	IDACORP, Inc.	$4.20	$7.10	$74.00	4.31%	9.59%	1.02	9.80%	59.15%	40.85%	4.00%	5.72%
16	NorthWestern Corporation	$2.80	$4.30	$53.55	2.76%	8.03%	1.01	8.14%	65.12%	34.88%	2.84%	3.02%
17	OGE Energy Corp.	$1.79	$2.95	$26.25	2.86%	11.24%	1.01	11.40%	60.68%	39.32%	4.48%	4.48%
18	Pinnacle West Capital Corporation	$3.85	$6.25	$70.00	4.27%	8.93%	1.02	9.12%	61.60%	38.40%	3.50%	4.64%
19	Portland General Electric Company	$2.60	$4.00	$42.25	4.30%	9.47%	1.02	9.67%	65.00%	35.00%	3.38%	4.27%
20	Southern Company	$3.10	$5.60	$32.25	1.89%	17.36%	1.01	17.53%	55.36%	44.64%	7.82%	8.75%
21	Xcel Energy Inc.	$3.00	$5.00	$43.70	5.47%	11.44%	1.03	11.75%	60.00%	40.00%	4.70%	6.10%
22	**Average**	**$3.18**	**$5.35**	**$50.90**	**3.88%**	**10.85%**	**1.02**	**11.05%**	**60.01%**	**39.99%**	**4.46%**	**5.71%**
23	**Median**											**5.72%**

Sources and Notes:
Cols. (1), (2) and (3): *The Value Line Investment Survey* , March 7, April 18, May, 9, and May 23, 2025.
Col. (4): [Col. (3) / Page 2 Col. (2)] ^ (1/number of years projected) - 1.
Col. (5): Col. (2) / Col. (3).
Col. (6): [2 * (1 + Col. (4))] / (2 + Col. (4)).
Col. (7): Col. (6) * Col. (5).
Col. (8): Col. (1) / Col. (2).
Col. (9): 1 - Col. (8).
Col. (10): Col. (9) * Col. (7).
Col. (11): Col. (10) + Page 2 Col. (9).

Valley Energy, Inc. / Citizens' Electric Company of Lewisburg, PA / Wellsboro Electric Company

Sustainable Growth Rate

Line	Company	13-Week Average Stock Price[1] (1)	2023 Book Value Per Share[2] (2)	Market to Book Ratio (3)	Common Shares Outstanding (in Millions)[2] 2023 (4)	Common Shares Outstanding (in Millions)[2] 3-5 Years (5)	Growth (6)	S Factor[3] (7)	V Factor[4] (8)	S * V (9)
1	Atmos Energy Corporation	$153.92	$73.20	2.10	148.49	185.00	3.73%	7.85%	52.44%	4.12%
2	New Jersey Resources Corporation	$48.02	$20.40	2.35	97.58	105.00	1.23%	2.89%	57.52%	1.66%
3	NiSource Inc.	$39.00	$17.40	2.24	447.38	525.00	2.70%	6.06%	55.39%	3.36%
4	Northwest Natural Holding Company	$41.89	$34.12	1.23	37.63	50.00	4.85%	5.96%	18.55%	1.10%
5	ONE Gas, Inc.	$75.22	$48.91	1.54	56.55	70.00	3.62%	5.57%	34.97%	1.95%
6	Southwest Gas Holdings, Inc.	$72.39	$46.25	1.57	71.56	75.00	0.79%	1.23%	36.11%	0.44%
7	Spire Inc.	$75.70	$50.29	1.51	53.20	72.00	5.17%	7.79%	33.57%	2.61%
8	Alliant Energy Corporation	$61.91	$26.46	2.34	256.10	257.00	0.06%	0.14%	57.26%	0.08%
9	Ameren Corporation	$97.85	$40.26	2.43	267.00	285.00	1.09%	2.66%	58.85%	1.56%
10	American Electric Power Company, Inc.	$104.80	$48.46	2.16	526.18	550.00	0.74%	1.60%	53.76%	0.86%
11	Duke Energy Corporation	$118.61	$61.15	1.94	771.00	780.00	0.19%	0.38%	48.44%	0.18%
12	Edison International	$56.52	$36.02	1.57	383.93	395.00	0.47%	0.75%	36.27%	0.27%
13	Entergy Corporation	$82.67	$34.35	2.41	425.70	460.00	1.30%	3.13%	58.45%	1.83%
14	Evergy, Inc.	$66.95	$42.06	1.59	229.73	230.00	0.02%	0.03%	37.18%	0.01%
15	IDACORP, Inc.	$115.71	$57.44	2.01	50.62	56.00	1.70%	3.42%	50.36%	1.72%
16	NorthWestern Corporation	$56.42	$45.48	1.24	61.25	64.00	0.73%	0.91%	19.38%	0.18%
17	OGE Energy Corp.	$44.53	$22.17	2.01	200.30	200.20	- 0.01%	- 0.02%	50.22%	- 0.01%
18	Pinnacle West Capital Corporation	$92.32	$54.47	1.69	113.42	125.00	1.63%	2.77%	41.00%	1.13%
19	Portland General Electric Company	$42.93	$32.81	1.31	101.16	120.00	2.89%	3.78%	23.58%	0.89%
20	Southern Company	$89.84	$28.82	3.12	1,091.00	1,120.00	0.44%	1.37%	67.92%	0.93%
21	Xcel Energy Inc.	$69.72	$31.74	2.20	554.94	595.00	1.17%	2.57%	54.48%	1.40%
	Average	**$76.52**	**$40.58**	**1.93**	**283.08**	**300.91**	**1.64%**	**2.90%**	**45.03%**	**1.25%**

Sources and Notes:
[1] S&P Global Market Intelligence, Downloaded on May 30, 2025.
[2] *The Value Line Investment Survey* , March 7, April 18, May, 9, and May 23, 2025.
[3] Expected Growth in the Number of Shares, Column (3) * Column (6).
[4] Expected Profit of Stock Investment, [1 - 1 / Column (3)].

Valley Energy, Inc. / Citizens' Electric Company of Lewisburg, PA / Wellsboro Electric Company

Constant Growth DCF Model
(Sustainable Growth Rate)

Line	Company	13-Week AVG Stock Price[1] (1)	Sustainable Growth[2] (2)	Annualized Dividend[3] (3)	Adjusted Yield (4)	Constant Growth DCF (5)
1	Atmos Energy Corporation	$153.92	9.27%	$3.48	2.47%	11.74%
2	New Jersey Resources Corporation	$48.02	7.97%	$1.80	4.05%	12.02%
3	NiSource Inc.	$39.00	7.81%	$1.12	3.10%	10.91%
4	Northwest Natural Holding Company	$41.89	4.74%	$1.96	4.90%	9.65%
5	ONE Gas, Inc.	$75.22	6.15%	$2.68	3.78%	9.93%
6	Southwest Gas Holdings, Inc.	$72.39	3.92%	$2.48	3.56%	7.48%
7	Spire Inc.	$75.70	5.33%	$3.14	4.37%	9.70%
8	Alliant Energy Corporation	$61.91	5.87%	$1.92	3.28%	9.16%
9	Ameren Corporation	$97.85	7.25%	$2.84	3.11%	10.37%
10	American Electric Power Company, Inc.	$104.80	6.20%	$3.72	3.77%	9.97%
11	Duke Energy Corporation	$118.61	4.18%	$4.18	3.67%	7.85%
12	Edison International	$56.52	5.92%	$3.31	6.20%	12.12%
13	Entergy Corporation	$82.67	4.64%	$2.40	3.04%	7.68%
14	Evergy, Inc.	$66.95	3.73%	$2.67	4.14%	7.87%
15	IDACORP, Inc.	$115.71	5.72%	$3.44	3.14%	8.87%
16	NorthWestern Corporation	$56.42	3.02%	$2.64	4.82%	7.84%
17	OGE Energy Corp.	$44.53	4.48%	$1.69	3.95%	8.43%
18	Pinnacle West Capital Corporation	$92.32	4.64%	$3.58	4.06%	8.69%
19	Portland General Electric Company	$42.93	4.27%	$2.00	4.86%	9.13%
20	Southern Company	$89.84	8.75%	$2.96	3.58%	12.34%
21	Xcel Energy Inc.	$69.72	6.10%	$2.28	3.47%	9.57%
22	**Average**	**$76.52**	**5.71%**	**$2.68**	**3.87%**	**9.59%**
23	**Median**					**9.57%**

Sources:
[1] S&P Global Market Intelligence, Downloaded on May 30, 2025.
[2] Exhibit CCW-6, page 1.
[3] *The Value Line Investment Survey*, March 7, April 18, May, 9, and May 23, 2025.

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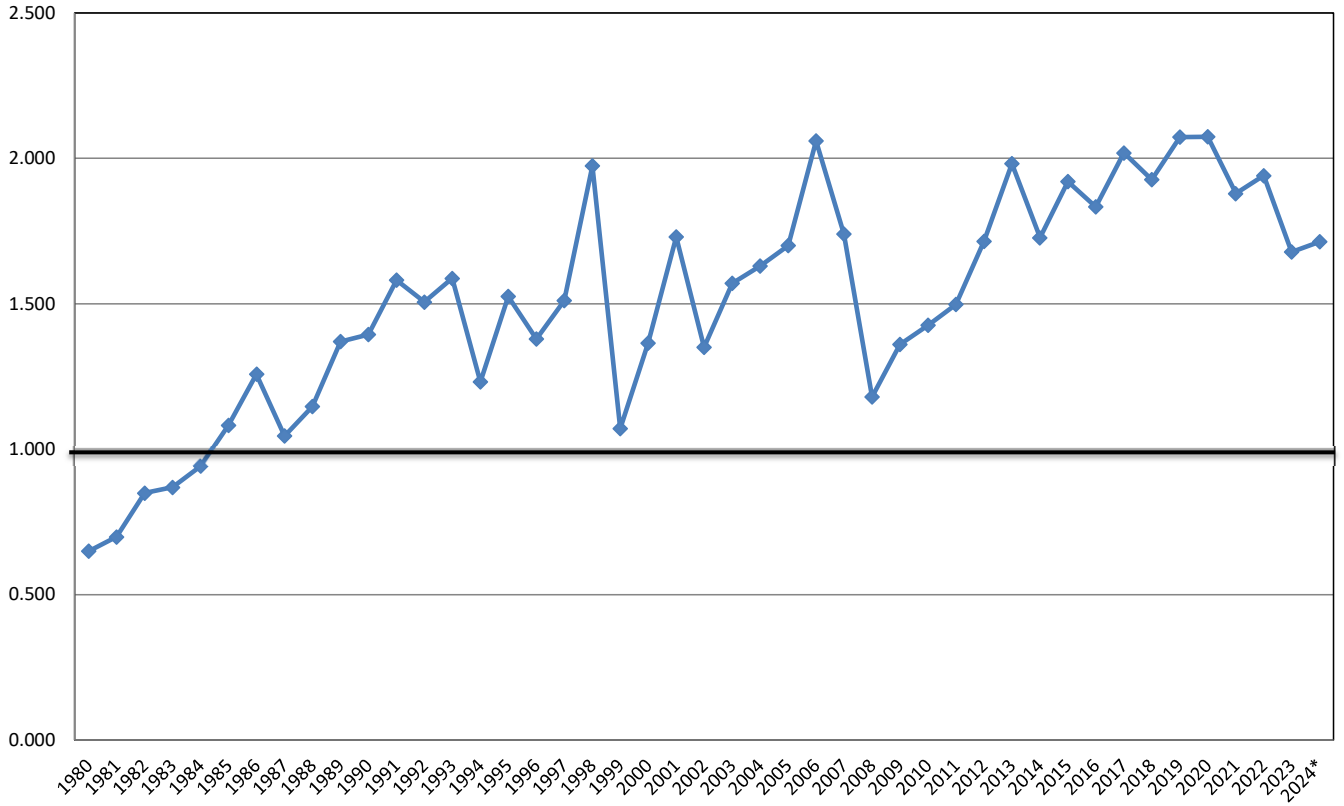
Multi-Stage Growth DCF Model

Line	Company	13-Week AVG Stock Price[1] (1)	Annualized Dividend[2] (2)	First Stage Growth[3] (3)	Second Stage Growth Year 6 (4)	Year 7 (5)	Year 8 (6)	Year 9 (7)	Year 10 (8)	Third Stage Growth[4] (9)	Multi-Stage Growth DCF (10)
1	Atmos Energy Corporation	$153.92	$3.48	7.26%	6.73%	6.20%	5.67%	5.15%	4.62%	4.09%	6.97%
2	New Jersey Resources Corporation	$48.02	$1.80	7.90%	7.27%	6.63%	6.00%	5.36%	4.73%	4.09%	9.02%
3	NiSource Inc.	$39.00	$1.12	7.80%	7.19%	6.57%	5.95%	5.33%	4.71%	4.09%	7.87%
4	Northwest Natural Holding Company	$41.89	$1.96	5.75%	5.47%	5.20%	4.92%	4.64%	4.37%	4.09%	9.48%
5	ONE Gas, Inc.	$75.22	$2.68	5.70%	5.43%	5.16%	4.89%	4.63%	4.36%	4.09%	8.19%
6	Southwest Gas Holdings, Inc.	$72.39	$2.48	11.04%	9.88%	8.72%	7.56%	6.41%	5.25%	4.09%	9.51%
7	Spire Inc.	$75.70	$3.14	7.04%	6.55%	6.06%	5.57%	5.07%	4.58%	4.09%	9.26%
8	Alliant Energy Corporation	$61.91	$1.92	6.53%	6.12%	5.71%	5.31%	4.90%	4.50%	4.09%	7.86%
9	Ameren Corporation	$97.85	$2.84	6.90%	6.43%	5.96%	5.50%	5.03%	4.56%	4.09%	7.70%
10	American Electric Power Company, Inc.	$104.80	$3.72	6.53%	6.12%	5.72%	5.31%	4.90%	4.50%	4.09%	8.39%
11	Duke Energy Corporation	$118.61	$4.18	6.42%	6.03%	5.64%	5.26%	4.87%	4.48%	4.09%	8.34%
12	Edison International	$56.52	$3.31	8.52%	7.78%	7.04%	6.30%	5.57%	4.83%	4.09%	11.93%
13	Entergy Corporation	$82.67	$2.40	9.40%	8.52%	7.63%	6.75%	5.86%	4.98%	4.09%	8.30%
14	Evergy, Inc.	$66.95	$2.67	5.67%	5.40%	5.14%	4.88%	4.62%	4.35%	4.09%	8.67%
15	IDACORP, Inc.	$115.71	$3.44	7.85%	7.23%	6.60%	5.97%	5.34%	4.72%	4.09%	8.01%
16	NorthWestern Corporation	$56.42	$2.64	6.37%	5.99%	5.61%	5.23%	4.85%	4.47%	4.09%	9.68%
17	OGE Energy Corp.	$44.53	$1.69	6.15%	5.81%	5.46%	5.12%	4.78%	4.43%	4.09%	8.57%
18	Pinnacle West Capital Corporation	$92.32	$3.58	3.03%	3.20%	3.38%	3.56%	3.74%	3.91%	4.09%	7.86%
19	Portland General Electric Company	$42.93	$2.00	3.92%	3.95%	3.98%	4.01%	4.03%	4.06%	4.09%	8.89%
20	Southern Company	$89.84	$2.96	6.70%	6.26%	5.83%	5.39%	4.96%	4.52%	4.09%	8.13%
21	Xcel Energy Inc.	$69.72	$2.28	7.88%	7.25%	6.62%	5.99%	5.35%	4.72%	4.09%	8.40%
22	**Average**	**$76.52**	**$2.68**	**6.87%**	**6.41%**	**5.95%**	**5.48%**	**5.02%**	**4.55%**	**4.09%**	**8.62%**
23	**Median**										**8.39%**

Sources:
[1] S&P Global Market Intelligence, Downloaded on May 30, 2025.
[2] *The Value Line Investment Survey*, March 7, April 18, May, 9, and May 23, 2025.
[3] Exhibit CCW-3
[4] *Blue Chip Fiancial Forecasts,* June 2, 2025, at page 14.

gy, Inc. / Citizens' Electric Company of Lewisburg, PA / Wellsboro Electr

Common Stock Market/Book Ratio



Source:
1980 - 2000: Mergent Public Utility Manual.
2001 - 2015: AUS Utility Reports, multiple dates.
2016 - 2023: Value Line Investment Survey, multiple dates.
* Value Line Investment Survey Reports March 7, April 18, May 9, and May 23, 2025.

Valley Energy, Inc. / Citizens' Electric Company of Lewisburg, PA / Wellsboro Electric Company

Equity Risk Premium - Treasury Bond

Line	Year	Authorized Electric Returns[1] (1)	30 yr. Treasury Bond Yield[2] (2)	Indicated Risk Premium (3)	Rolling 5 - Year Average (4)	Rolling 10 - Year Average (5)
1	1986	13.93%	7.80%	6.13%		
2	1987	12.99%	8.58%	4.41%		
3	1988	12.79%	8.96%	3.83%		
4	1989	12.97%	8.45%	4.52%		
5	1990	12.70%	8.61%	4.09%	4.60%	
6	1991	12.55%	8.14%	4.41%	4.25%	
7	1992	12.09%	7.67%	4.42%	4.26%	
8	1993	11.41%	6.60%	4.81%	4.45%	
9	1994	11.34%	7.37%	3.97%	4.34%	
10	1995	11.55%	6.88%	4.67%	4.46%	4.53%
11	1996	11.39%	6.70%	4.69%	4.51%	4.38%
12	1997	11.40%	6.61%	4.79%	4.59%	4.42%
13	1998	11.66%	5.58%	6.08%	4.84%	4.65%
14	1999	10.77%	5.87%	4.90%	5.03%	4.68%
15	2000	11.43%	5.94%	5.49%	5.19%	4.82%
16	2001	11.09%	5.49%	5.60%	5.37%	4.94%
17	2002	11.16%	5.43%	5.73%	5.56%	5.07%
18	2003	10.97%	4.96%	6.01%	5.55%	5.19%
19	2004	10.75%	5.05%	5.70%	5.71%	5.37%
20	2005	10.54%	4.65%	5.89%	5.79%	5.49%
21	2006	10.34%	4.87%	5.47%	5.76%	5.57%
22	2007	10.31%	4.83%	5.48%	5.71%	5.64%
23	2008	10.37%	4.28%	6.09%	5.73%	5.64%
24	2009	10.52%	4.07%	6.45%	5.88%	5.79%
25	2010	10.29%	4.25%	6.04%	5.91%	5.85%
26	2011	10.19%	3.91%	6.28%	6.07%	5.91%
27	2012	10.02%	2.92%	7.10%	6.39%	6.05%
28	2013	9.82%	3.45%	6.37%	6.45%	6.09%
29	2014	9.76%	3.34%	6.42%	6.44%	6.16%
30	2015	9.60%	2.84%	6.76%	6.58%	6.24%
31	2016	9.60%	2.60%	7.00%	6.73%	6.40%
32	2017	9.68%	2.90%	6.78%	6.66%	6.53%
33	2018	9.56%	3.11%	6.45%	6.68%	6.56%
34	2019	9.65%	2.58%	7.07%	6.81%	6.63%
35	2020	9.39%	1.56%	7.83%	7.02%	6.80%
36	2021	9.39%	2.05%	7.34%	7.09%	6.91%
37	2022	9.58%	3.12%	6.46%	7.03%	6.85%
38	2023	9.66%	4.09%	5.57%	6.85%	6.77%
39	2024	9.78%	4.41%	5.37%	6.51%	6.66%
40	2025 [3]	9.72%	4.71%	5.01%	5.95%	6.49%
41	**Average**	**10.82%**	**5.13%**	**5.69%**	**5.74%**	**5.78%**
42	**Minimum**				**4.25%**	**4.38%**
43	**Maximum**				**7.09%**	**6.91%**

Sources:

[1] *Regulatory Research Associates, Inc*., Regulatory Focus, Major Rate Case Decisions, Jan. 1997 p. 5, and Jan. 2011 p. 3.
S&P Global Market Intelligence, RRA Regulatory Focus, Major Rate Case Decisions, January - March, 2025
April 25, 2025 at page 3.
2006 - 2024 Authorized Returns exclude limited issue rider cases.

[2] St. Louis Federal Reserve: Economic Research, http://research.stlouisfed.org/.
The yields from 2002 to 2005 represent the 20-Year Treasury yields obtained from the Federal Reserve Bank.

[3] Data represents January - March, 2025.

Valley Energy, Inc. / Citizens' Electric Company of Lewisburg, PA / Wellsboro Electric Company

Equity Risk Premium - Treasury Bond

Line	Year	Authorized Gas Returns[1] (1)	30 yr. Treasury Bond Yield[2] (2)	Indicated Risk Premium (3)	Rolling 5 - Year Average (4)	Rolling 10 - Year Average (5)
1	1986	13.46%	7.80%	5.66%		
2	1987	12.74%	8.58%	4.16%		
3	1988	12.85%	8.96%	3.89%		
4	1989	12.88%	8.45%	4.43%		
5	1990	12.67%	8.61%	4.06%	4.44%	
6	1991	12.46%	8.14%	4.32%	4.17%	
7	1992	12.01%	7.67%	4.34%	4.21%	
8	1993	11.35%	6.60%	4.75%	4.38%	
9	1994	11.35%	7.37%	3.98%	4.29%	
10	1995	11.43%	6.88%	4.55%	4.39%	4.42%
11	1996	11.19%	6.70%	4.49%	4.42%	4.30%
12	1997	11.29%	6.61%	4.68%	4.49%	4.35%
13	1998	11.51%	5.58%	5.93%	4.73%	4.55%
14	1999	10.66%	5.87%	4.79%	4.89%	4.59%
15	2000	11.39%	5.94%	5.45%	5.07%	4.73%
16	2001	10.95%	5.49%	5.46%	5.26%	4.84%
17	2002	11.03%	5.43%	5.60%	5.45%	4.97%
18	2003	10.99%	4.96%	6.03%	5.47%	5.10%
19	2004	10.59%	5.05%	5.54%	5.62%	5.25%
20	2005	10.46%	4.65%	5.81%	5.69%	5.38%
21	2006	10.40%	4.87%	5.53%	5.70%	5.48%
22	2007	10.22%	4.83%	5.39%	5.66%	5.55%
23	2008	10.39%	4.28%	6.11%	5.68%	5.57%
24	2009	10.22%	4.07%	6.15%	5.80%	5.71%
25	2010	10.15%	4.25%	5.90%	5.81%	5.75%
26	2011	9.92%	3.91%	6.01%	5.91%	5.81%
27	2012	9.94%	2.92%	7.02%	6.24%	5.95%
28	2013	9.68%	3.45%	6.23%	6.26%	5.97%
29	2014	9.78%	3.34%	6.44%	6.32%	6.06%
30	2015	9.60%	2.84%	6.76%	6.49%	6.15%
31	2016	9.54%	2.60%	6.94%	6.68%	6.29%
32	2017	9.72%	2.90%	6.83%	6.64%	6.44%
33	2018	9.59%	3.11%	6.48%	6.69%	6.48%
34	2019	9.71%	2.58%	7.13%	6.83%	6.57%
35	2020	9.46%	1.56%	7.90%	7.05%	6.77%
36	2021	9.56%	2.05%	7.51%	7.17%	6.92%
37	2022	9.53%	3.12%	6.41%	7.08%	6.86%
38	2023	9.60%	4.09%	5.50%	6.89%	6.79%
39	2024	9.71%	4.41%	5.30%	6.52%	6.68%
40	2025 [3]	9.73%	4.71%	5.02%	5.95%	6.50%
41	**Average**	**10.74%**	**5.13%**	**5.61%**	**5.68%**	**5.70%**
42	**Minimum**				**4.17%**	**4.30%**
43	**Maximum**				**7.17%**	**6.92%**

Sources:

[1] *Regulatory Research Associates, Inc*., Regulatory Focus, Major Rate Case Decisions, Jan. 1997 p. 5, and Jan. 2011 p. 3.
S&P Global Market Intelligence, RRA Regulatory Focus, Major Rate Case Decisions, January - March, 2025
April 25, 2025 at page 3.

[2] St. Louis Federal Reserve: Economic Research, http://research.stlouisfed.org/.
The yields from 2002 to 2005 represent the 20-Year Treasury yields obtained from the Federal Reserve Bank.

[3] Data represents January - March, 2025.

Valley Energy, Inc. / Citizens' Electric Company of Lewisburg, PA / Wellsboro Electric Company

Equity Risk Premium - Utility Bond

Line	Year	Authorized Electric Returns[1] (1)	Average "A" Rated Utility Bond Yield[2] (2)	Indicated Risk Premium (3)	Rolling 5 - Year Average (4)	Rolling 10 - Year Average (5)
1	1986	13.93%	9.58%	4.35%		
2	1987	12.99%	10.10%	2.89%		
3	1988	12.79%	10.49%	2.30%		
4	1989	12.97%	9.77%	3.20%		
5	1990	12.70%	9.86%	2.84%	3.12%	
6	1991	12.55%	9.36%	3.19%	2.88%	
7	1992	12.09%	8.69%	3.40%	2.99%	
8	1993	11.41%	7.59%	3.82%	3.29%	
9	1994	11.34%	8.31%	3.03%	3.26%	
10	1995	11.55%	7.89%	3.66%	3.42%	3.27%
11	1996	11.39%	7.75%	3.64%	3.51%	3.20%
12	1997	11.40%	7.60%	3.80%	3.59%	3.29%
13	1998	11.66%	7.04%	4.62%	3.75%	3.52%
14	1999	10.77%	7.62%	3.15%	3.77%	3.52%
15	2000	11.43%	8.24%	3.19%	3.68%	3.55%
16	2001	11.09%	7.76%	3.33%	3.62%	3.56%
17	2002	11.16%	7.37%	3.79%	3.61%	3.60%
18	2003	10.97%	6.58%	4.39%	3.57%	3.66%
19	2004	10.75%	6.16%	4.59%	3.86%	3.82%
20	2005	10.54%	5.65%	4.89%	4.20%	3.94%
21	2006	10.34%	6.07%	4.27%	4.39%	4.00%
22	2007	10.31%	6.07%	4.24%	4.48%	4.04%
23	2008	10.37%	6.53%	3.84%	4.37%	3.97%
24	2009	10.52%	6.04%	4.48%	4.34%	4.10%
25	2010	10.29%	5.46%	4.83%	4.33%	4.26%
26	2011	10.19%	5.04%	5.15%	4.51%	4.45%
27	2012	10.02%	4.13%	5.89%	4.84%	4.66%
28	2013	9.82%	4.48%	5.34%	5.14%	4.75%
29	2014	9.76%	4.28%	5.48%	5.34%	4.84%
30	2015	9.60%	4.12%	5.48%	5.47%	4.90%
31	2016	9.60%	3.93%	5.66%	5.57%	5.04%
32	2017	9.68%	4.00%	5.68%	5.53%	5.18%
33	2018	9.56%	4.25%	5.31%	5.52%	5.33%
34	2019	9.65%	3.77%	5.88%	5.60%	5.47%
35	2020	9.39%	3.02%	6.37%	5.78%	5.62%
36	2021	9.39%	3.11%	6.28%	5.91%	5.74%
37	2022	9.58%	4.72%	4.86%	5.74%	5.64%
38	2023	9.66%	5.54%	4.12%	5.50%	5.51%
39	2024	9.78%	5.54%	4.24%	5.17%	5.39%
40	2025 [3]	9.72%	5.77%	3.95%	4.69%	5.24%
41	**Average**	**10.82%**	**6.48%**	**4.34%**	**4.40%**	**4.42%**
42	**Minimum**				**2.88%**	**3.20%**
43	**Maximum**				**5.91%**	**5.74%**

Sources:

[1] *Regulatory Research Associates, Inc*., Regulatory Focus, Major Rate Case Decisions, Jan. 1997 p. 5, and Jan. 2011 p. 3.
S&P Global Market Intelligence, RRA Regulatory Focus, Major Rate Case Decisions, January - March, 2025
April 25, 2025 at page 3.
2006 - 2024 Authorized Returns exclude limited issue rider cases.

[2] The utility bond yields for the period 1980-2005 were obtained from the St. Louis Federal Reserve: Economic Research, htt
The utility bond yields from 2006-2025 were obtained from the Mergent Bond Record

[3] Data represents January - March, 2025.

Valley Energy, Inc. / Citizens' Electric Company of Lewisburg, PA / Wellsboro Electric Company

Equity Risk Premium - Utility Bond

Line	Year	Authorized Gas Returns[1] (1)	Average "A" Rated Utility Bond Yield[2] (2)	Indicated Risk Premium (3)	Rolling 5 - Year Average (4)	Rolling 10 - Year Average (5)
1	1986	13.46%	9.58%	3.88%		
2	1987	12.74%	10.10%	2.64%		
3	1988	12.85%	10.49%	2.36%		
4	1989	12.88%	9.77%	3.11%		
5	1990	12.67%	9.86%	2.81%	2.96%	
6	1991	12.46%	9.36%	3.10%	2.80%	
7	1992	12.01%	8.69%	3.32%	2.94%	
8	1993	11.35%	7.59%	3.76%	3.22%	
9	1994	11.35%	8.31%	3.04%	3.21%	
10	1995	11.43%	7.89%	3.54%	3.35%	3.16%
11	1996	11.19%	7.75%	3.44%	3.42%	3.11%
12	1997	11.29%	7.60%	3.69%	3.49%	3.22%
13	1998	11.51%	7.04%	4.47%	3.64%	3.43%
14	1999	10.66%	7.62%	3.04%	3.64%	3.42%
15	2000	11.39%	8.24%	3.15%	3.56%	3.45%
16	2001	10.95%	7.76%	3.19%	3.51%	3.46%
17	2002	11.03%	7.37%	3.66%	3.50%	3.50%
18	2003	10.99%	6.58%	4.41%	3.49%	3.56%
19	2004	10.59%	6.16%	4.43%	3.77%	3.70%
20	2005	10.46%	5.65%	4.81%	4.10%	3.83%
21	2006	10.40%	6.07%	4.33%	4.33%	3.92%
22	2007	10.22%	6.07%	4.15%	4.43%	3.96%
23	2008	10.39%	6.53%	3.86%	4.32%	3.90%
24	2009	10.22%	6.04%	4.18%	4.27%	4.02%
25	2010	10.15%	5.46%	4.69%	4.24%	4.17%
26	2011	9.92%	5.04%	4.88%	4.35%	4.34%
27	2012	9.94%	4.13%	5.81%	4.68%	4.55%
28	2013	9.68%	4.48%	5.20%	4.95%	4.63%
29	2014	9.78%	4.28%	5.50%	5.22%	4.74%
30	2015	9.60%	4.12%	5.49%	5.38%	4.81%
31	2016	9.54%	3.93%	5.61%	5.52%	4.94%
32	2017	9.72%	4.00%	5.72%	5.50%	5.09%
33	2018	9.59%	4.25%	5.34%	5.53%	5.24%
34	2019	9.71%	3.77%	5.94%	5.62%	5.42%
35	2020	9.46%	3.02%	6.44%	5.81%	5.59%
36	2021	9.56%	3.11%	6.45%	5.98%	5.75%
37	2022	9.53%	4.72%	4.81%	5.80%	5.65%
38	2023	9.60%	5.54%	4.06%	5.54%	5.54%
39	2024	9.71%	5.54%	4.17%	5.19%	5.40%
40	2025 [3]	9.73%	5.77%	3.96%	4.69%	5.25%
41	**Average**	**10.74%**	**6.48%**	**4.26%**	**4.33%**	**4.35%**
42	**Minimum**				**2.80%**	**3.11%**
43	**Maximum**				**5.98%**	**5.75%**

Sources:

[1] *Regulatory Research Associates, Inc*., Regulatory Focus, Major Rate Case Decisions, Jan. 1997 p. 5, and Jan. 2011 p. 3.
S&P Global Market Intelligence, RRA Regulatory Focus, Major Rate Case Decisions, January - March, 2025
April 25, 2025 at page 3.

[2] The utility bond yields for the period 1980-2005 were obtained from the St. Louis Federal Reserve: Economic Research, http://researc

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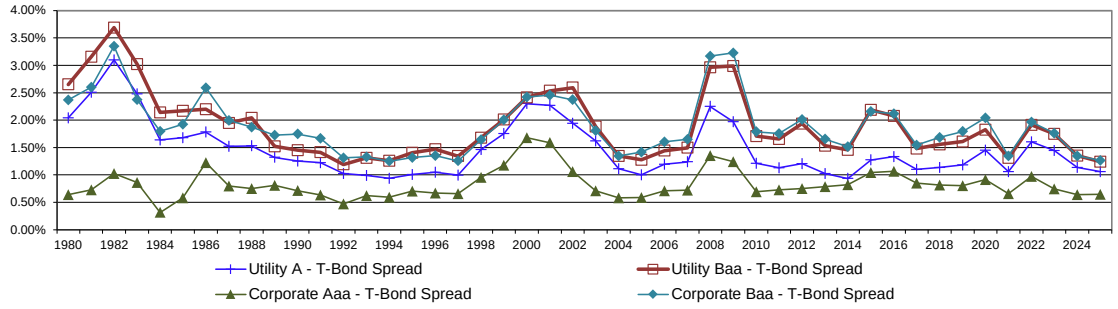
Bond Yield Spreads

			Public Utility Bond				Corporate Bond				Utility to Corporate	
Line	Year	T-Bond Yield[1]	A[2]	Baa[2]	A-T-Bond Spread	Baa-T-Bond Spread	Aaa[3]	Baa[3]	Aaa-T-Bond Spread	Baa-T-Bond Spread	Baa Spread	A-Aaa Spread
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	1980	11.30%	13.34%	13.95%	2.04%	2.65%	11.94%	13.67%	0.64%	2.37%	0.28%	1.40%
2	1981	13.44%	15.95%	16.60%	2.51%	3.16%	14.17%	16.04%	0.73%	2.60%	0.56%	1.78%
3	1982	12.76%	15.86%	16.45%	3.10%	3.69%	13.79%	16.11%	1.03%	3.35%	0.34%	2.07%
4	1983	11.18%	13.66%	14.20%	2.48%	3.02%	12.04%	13.55%	0.86%	2.38%	0.65%	1.62%
5	1984	12.39%	14.03%	14.53%	1.64%	2.14%	12.71%	14.19%	0.32%	1.80%	0.34%	1.32%
6	1985	10.79%	12.47%	12.96%	1.68%	2.17%	11.37%	12.72%	0.58%	1.93%	0.24%	1.10%
7	1986	7.80%	9.58%	10.00%	1.78%	2.20%	9.02%	10.39%	1.22%	2.59%	-0.39%	0.56%
8	1987	8.58%	10.10%	10.53%	1.52%	1.95%	9.38%	10.58%	0.80%	2.00%	-0.05%	0.72%
9	1988	8.96%	10.49%	11.00%	1.53%	2.04%	9.71%	10.83%	0.75%	1.87%	0.17%	0.78%
10	1989	8.45%	9.77%	9.97%	1.32%	1.52%	9.26%	10.18%	0.81%	1.73%	-0.21%	0.51%
11	1990	8.61%	9.86%	10.06%	1.25%	1.45%	9.32%	10.36%	0.71%	1.75%	-0.30%	0.54%
12	1991	8.14%	9.36%	9.55%	1.22%	1.41%	8.77%	9.80%	0.63%	1.67%	-0.25%	0.59%
13	1992	7.67%	8.69%	8.86%	1.02%	1.19%	8.14%	8.98%	0.47%	1.31%	-0.12%	0.55%
14	1993	6.60%	7.59%	7.91%	0.99%	1.31%	7.22%	7.93%	0.62%	1.33%	-0.02%	0.37%
15	1994	7.37%	8.31%	8.63%	0.94%	1.26%	7.96%	8.62%	0.59%	1.25%	0.01%	0.35%
16	1995	6.88%	7.89%	8.29%	1.01%	1.41%	7.59%	8.20%	0.71%	1.32%	0.09%	0.30%
17	1996	6.70%	7.75%	8.17%	1.05%	1.47%	7.37%	8.05%	0.67%	1.35%	0.12%	0.38%
18	1997	6.61%	7.60%	7.95%	0.99%	1.34%	7.26%	7.86%	0.66%	1.26%	0.09%	0.34%
19	1998	5.58%	7.04%	7.26%	1.46%	1.68%	6.53%	7.22%	0.95%	1.64%	0.04%	0.51%
20	1999	5.87%	7.62%	7.88%	1.75%	2.01%	7.04%	7.87%	1.18%	2.01%	0.01%	0.58%
21	2000	5.94%	8.24%	8.36%	2.30%	2.42%	7.62%	8.36%	1.68%	2.42%	-0.01%	0.62%
22	2001	5.49%	7.76%	8.03%	2.27%	2.54%	7.08%	7.95%	1.59%	2.45%	0.08%	0.68%
23	2002	5.43%	7.37%	8.02%	1.94%	2.59%	6.49%	7.80%	1.06%	2.37%	0.22%	0.88%
24	2003	4.96%	6.58%	6.84%	1.62%	1.89%	5.67%	6.77%	0.71%	1.81%	0.08%	0.91%
25	2004	5.05%	6.16%	6.40%	1.11%	1.35%	5.63%	6.39%	0.58%	1.35%	0.00%	0.53%
26	2005	4.65%	5.65%	5.93%	1.00%	1.28%	5.24%	6.06%	0.59%	1.42%	-0.14%	0.41%
27	2006	4.87%	6.07%	6.32%	1.20%	1.44%	5.58%	6.48%	0.71%	1.61%	-0.16%	0.48%
28	2007	4.83%	6.07%	6.33%	1.24%	1.50%	5.56%	6.48%	0.72%	1.65%	-0.15%	0.52%
29	2008	4.28%	6.53%	7.25%	2.25%	2.97%	5.63%	7.45%	1.35%	3.17%	-0.20%	0.90%
30	2009	4.07%	6.04%	7.06%	1.97%	2.99%	5.31%	7.30%	1.24%	3.23%	-0.24%	0.73%
31	2010	4.25%	5.46%	5.96%	1.21%	1.71%	4.94%	6.04%	0.69%	1.79%	-0.08%	0.52%
32	2011	3.91%	5.04%	5.57%	1.13%	1.66%	4.64%	5.66%	0.73%	1.75%	-0.10%	0.40%
33	2012	2.92%	4.13%	4.86%	1.21%	1.93%	3.67%	4.94%	0.75%	2.01%	-0.08%	0.46%
34	2013	3.45%	4.48%	4.98%	1.03%	1.54%	4.24%	5.10%	0.79%	1.65%	-0.12%	0.24%
35	2014	3.34%	4.28%	4.80%	0.94%	1.46%	4.16%	4.85%	0.82%	1.51%	-0.05%	0.12%
36	2015	2.84%	4.12%	5.03%	1.27%	2.19%	3.89%	5.00%	1.05%	2.16%	0.03%	0.23%
37	2016	2.60%	3.93%	4.68%	1.34%	2.08%	3.67%	4.72%	1.07%	2.12%	-0.04%	0.27%
38	2017	2.90%	4.00%	4.38%	1.10%	1.48%	3.74%	4.44%	0.85%	1.55%	-0.06%	0.26%
39	2018	3.11%	4.25%	4.67%	1.14%	1.56%	3.93%	4.80%	0.82%	1.69%	-0.13%	0.32%
40	2019	2.58%	3.77%	4.19%	1.19%	1.61%	3.39%	4.38%	0.81%	1.79%	-0.18%	0.38%
41	2020	1.56%	3.02%	3.39%	1.45%	1.83%	2.48%	3.60%	0.91%	2.04%	-0.21%	0.54%
42	2021	2.05%	3.11%	3.36%	1.06%	1.31%	2.71%	3.40%	0.66%	1.35%	-0.04%	0.40%
43	2022	3.12%	4.72%	5.03%	1.61%	1.91%	4.09%	5.08%	0.97%	1.97%	-0.05%	0.64%
44	2023	4.09%	5.54%	5.84%	1.45%	1.75%	4.84%	5.85%	0.75%	1.76%	-0.01%	0.70%
45	2024	4.41%	5.54%	5.76%	1.14%	1.36%	5.04%	5.75%	0.64%	1.35%	0.01%	0.50%
46	2025[4]	4.71%	5.77%	5.95%	1.06%	1.24%	5.36%	5.98%	0.65%	1.27%	-0.02%	0.42%
47	**Average**	**6.02%**	**7.49%**	**7.91%**	**1.47%**	**1.88%**	**6.85%**	**7.91%**	**0.83%**	**1.89%**	**0.00%**	**0.64%**

Yield Spreads
Treasury Vs. Corporate & Treasury Vs. Utility



Sources:
[1] St. Louis Federal Reserve: Economic Research, http://research.stlouisfed.org/.
[2] The utility yields for the period 1980-2000 were obtained from Mergent Public Utility Manual, Mergent Weekly News Reports, 2003.
The utility yields for the period 2001-2024 were obtained from the Mergent Bond Record.
[3] The corporate yields for the period 1980-2005 were obtained from the St. Louis Federal Reserve: Economic Research, http://research.stlouisfed.org/.
The corporate yields from 2006-2025 were obtained from the Mergent Bond Record.
[4] Data represents January - March, 2025.

Valley Energy, Inc. / Citizens' Electric Company of Lewisburg, PA / Wellsboro Electric

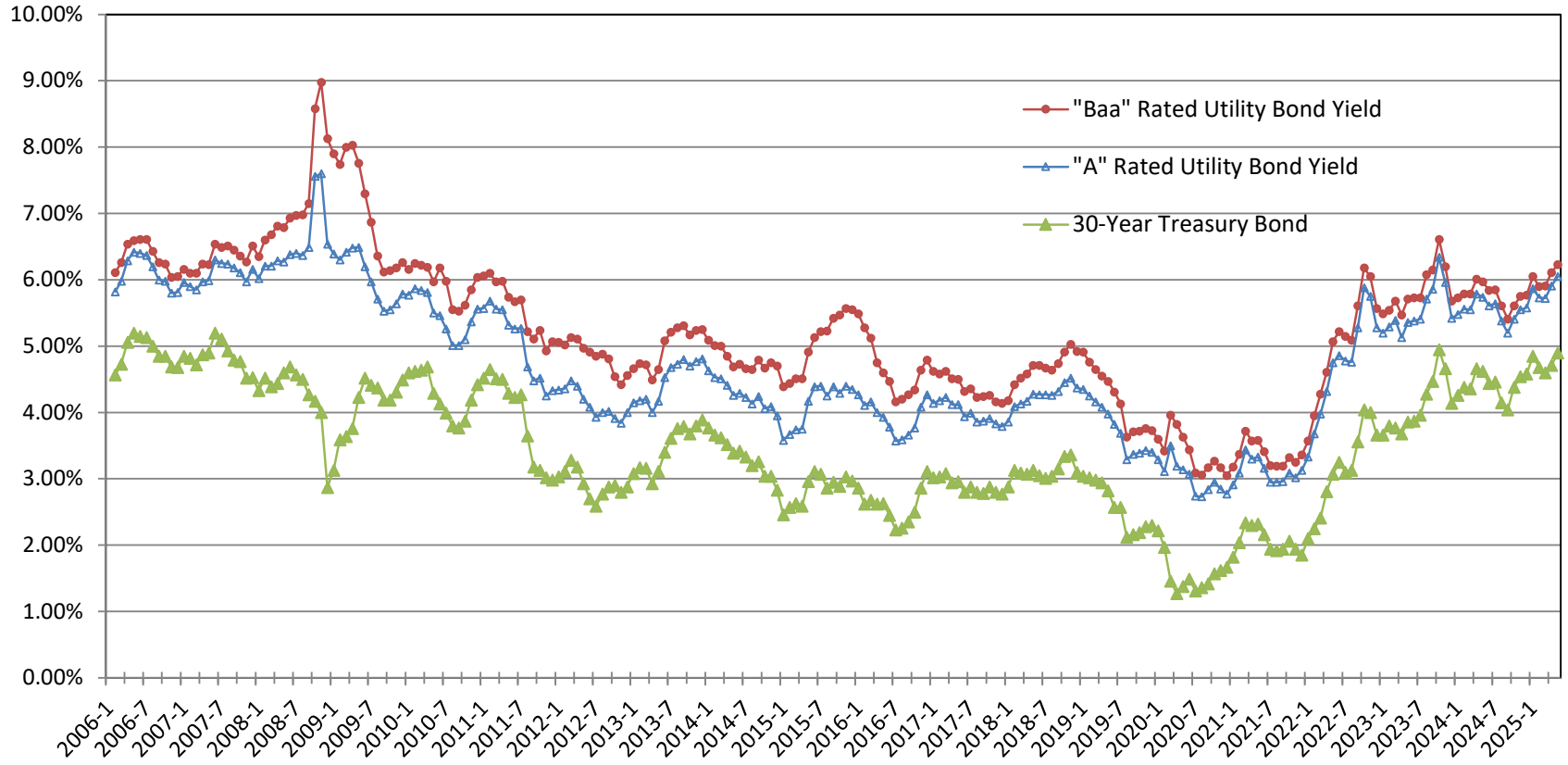
3 and 6 Month Treasury and Utility Bond Yields

Line	Date	Treasury Bond Yield[1] (1)	"A" Rated Utility Bond Yield[2] (2)	"Baa" Rated Utility Bond Yield[2] (3)
1	May-25	4.90%	6.05%	6.23%
2	April-25	4.71%	5.91%	6.11%
3	March-25	4.60%	5.72%	5.91%
4	February-25	4.68%	5.73%	5.90%
5	January-25	4.85%	5.87%	6.05%
6	December-24	4.58%	5.58%	5.77%
7	**3-Month Average**	**4.74%**	**5.89%**	**6.08%**
8	**Spread To Treasury**		**1.15%**	**1.34%**
9	**6-Month Average**	**4.72%**	**5.81%**	**6.00%**
10	**Spread To Treasury**		**1.09%**	**1.28%**

Sources:
[1] St. Louis Federal Reserve: Economic Research, http://research.stlouisfed.org.
[2] Mergent Bond Record.

Valley Energy, Inc. / Citizens' Electric Company of Lewisburg, PA / Wellsboro Electric Company

Trends in Bond Yields



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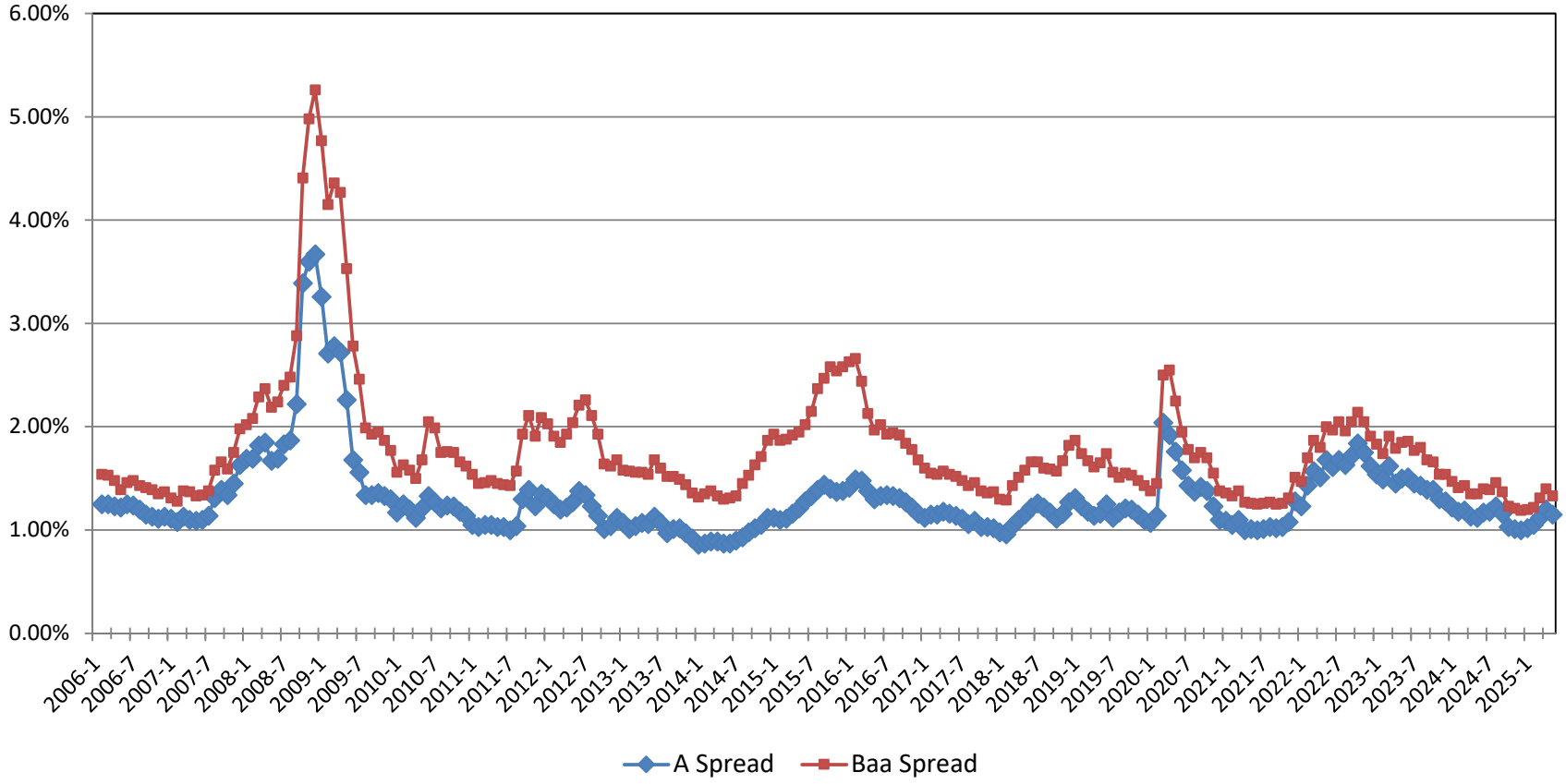
Sources:
Mergent Bond Record.
www.moodys.com, Bond Yields and Key Indicators.
St. Louis Federal Reserve: Economic Research, http://research.stlouisfed.org/

Valley Energy, Inc. / Citizens' Electric Company of Lewisburg, PA / Wellsboro Electric Company

Yield Spread Between Utility Bonds and 30-Year Treasury Bonds



Sources:
Mergent Bond Record.
www.moodys.com, Bond Yields and Key Indicators.
St. Louis Federal Reserve: Economic Research, http://research.stlouisfed.org/

Valley Energy, Inc. / Citizens' Electric Company of Lewisburg, PA / Wellsboro Electric Company

Beta

Line	Company	Beta[1]	Historical Beta[2]	S&P Global Market Intelligence Beta[3]	3-Year VL Methodolgy Beta[4]
1	Atmos Energy Corporation	0.75	0.77	0.48	0.73
2	New Jersey Resources Corporation	0.85	0.86	0.48	0.70
3	NiSource Inc.	0.85	0.78	0.50	0.82
4	Northwest Natural Holding Company	0.80	0.73	0.43	0.74
5	ONE Gas, Inc.	0.80	0.76	0.44	0.72
6	Southwest Gas Holdings, Inc.	0.80	0.84	0.47	0.80
7	Spire Inc.	0.80	0.76	0.48	0.73
8	Alliant Energy Corporation	0.95	0.78	0.45	0.76
9	Ameren Corporation	0.90	0.75	0.46	0.72
10	American Electric Power Company, Inc.	0.85	0.70	0.40	0.64
11	Duke Energy Corporation	0.70	0.71	0.36	0.62
12	Edison International	0.90	0.79	0.53	0.86
13	Entergy Corporation	1.00	0.79	0.50	0.76
14	Evergy, Inc.	0.95	0.95	0.43	0.71
15	IDACORP, Inc.	0.75	0.75	0.42	0.65
16	NorthWestern Corporation	0.80	0.78	0.46	0.69
17	OGE Energy Corp.	1.05	0.96	0.58	0.80
18	Pinnacle West Capital Corporation	0.80	0.77	0.48	0.72
19	Portland General Electric Company	0.80	0.78	0.42	0.72
20	Southern Company	0.75	0.72	0.42	0.61
21	Xcel Energy Inc.	0.75	0.69	0.42	0.69
22	**Average**	**0.84**	**0.78**	**0.46**	**0.72**
23	**Median**	**0.80**	**0.77**	**0.46**	**0.72**

Source:

[1] *The Value Line Investment Survey* , March 7, April 18, May, 9, and May 23, 2025.

[2] Value Line Software Analyzer.

[3] S&P Global Market Intelligence, betas for the period 5/30/2020 - 5/30/2025.

[4] S&P Global Market Intelligence, betas for the period 5/30/2022 - 5/30/2025.

Valley Energy, Inc. / Citizens' Electric Company of Lewisburg, PA / Wellsboro Electric

CAPM Return

Line	Description	Kroll Normalized MRP (1)	Risk Premium Derived MRP (2)	Average FERC S&P 500 DCF Derived MRP (3)
	Current Beta			
1	Risk-Free Rate[1,2]	4.77%	4.50%	4.50%
2	Market Risk Premium	5.50%	7.20%	7.85%
3	Beta[7]	0.84	0.84	0.84
4	**CAPM**	**9.38%**	**10.53%**	**11.08%**
	Historical Beta			
5	Risk-Free Rate[1,2]	4.77%	4.50%	4.50%
6	Market Risk Premium[1,3]	5.50%	7.20%	7.85%
7	Beta[7]	0.78	0.78	0.78
8	**CAPM**	**9.07%**	**10.13%**	**10.64%**
	Current S&P Global Market Intelligence Beta			
9	Risk-Free Rate[1,2]	4.77%	4.50%	4.50%
10	Market Risk Premium[1,3]	5.50%	7.20%	7.85%
11	Beta[7]	0.46	0.46	0.46
12	**CAPM**	**7.29%**	**7.80%**	**8.09%**
	3-Year S&P Global Market Intelligence Beta Adjusted Using VL Methodology			
13	Risk-Free Rate[1,2]	4.77%	4.50%	4.50%
14	Market Risk Premium[1,3]	5.50%	7.20%	7.85%
15	Beta[4]	0.72	0.72	0.72
16	**CAPM**	**8.74%**	**9.70%**	**10.17%**

Sources:

[1] *Kroll Cost of Capital Navigator.*

[2] *Blue Chip Financial Forecast June 2, 2025.*

[3] Exhibit CCW-15, page 2

[4] Exhibit CCW-14.

Valley Energy, Inc. / Citizens' Electric Company of Lewisburg, PA / Wellsboro Electric Company

Development of the Market Risk Premium

Line	Description	MRP
Risk Premium Based Method:		
1	Lg. Co. Stock Real Market Return	9.02% [1]
2	Projected Consumer Price Index	2.50% [2]
3	Expected Market Return	11.75%
4	Risk-Free Rate	4.50% [2]
5	Market Risk Premium	**7.20%**
FERC S&P 500 (Dividend Companies) 1-Step DCF Based Method:		
6	S&P 500 Growth	10.40% [3]
7	Index Dividend Yield	1.70% [3]
8	Adjusted Yield	1.79%
9	Expected Market Return	12.19%
10	Risk-Free Rate	4.50% [2]
11	Market Risk Premium	**7.70%**
FERC S&P 500 (All Companies) 1-Step DCF Based Method:		
12	Short-Term S&P 500 Growth	10.90% [4]
13	Index Dividend Yield	1.50% [4]
14	Adjusted Yield	1.58%
15	Expected Market Return	12.48%
16	Risk-Free Rate	4.50% [2]
17	Market Risk Premium	**8.00%**
18	Average DCF Based MRP	**7.85%**

Sources & Note:

[1] Morningstar Direct.

[2] *Blue Chip Financial Forecast June 2, 2025.*

[3] S&P 500 1-Step DCF through May 30, 2025 for Dividend Paying Companies.

[4] S&P 500 1-Step DCF through May 30, 2025 for all Companies.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No. R-2025-3054394
	:	R-2025-3054393
Citizens' Electric Company of Lewisburg, PA, Valley Energy, Inc., and Wellsboro Electric Company	:	R-2025-3054392

VERIFICATION

I, Christopher C. Walters, hereby state that the facts above set forth in my Direct Testimony, OCA Statement No. 2, are true and correct to the best of my knowledge, information, and belief and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa.C.S. § 4904 (relating to unsworn falsification to authorities).

DATED: July 15, 2025

Signature: */s/ Christopher C. Walters*
Christopher C. Walters

Address: Brubaker & Associates, Inc.
16690 Swingley Ridge Road
Suite 140
Chesterfield, MO 63017

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	Docket No.: R-2025-3054394
v.	:	
	:	
Citizens' Electric Company of Lewisburg	:	

DIRECT TESTIMONY

OF

Michael Deupree

On behalf of the

PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

OCA Statement 3

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I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS?

A. My name is Michael W. Deupree. My business address is 5800 One Perkins Place Drive, Suite 5-F, Baton Rouge, Louisiana, 70808.

Q. PLEASE STATE YOUR OCCUPATION AND CURRENT PLACE OF EMPLOYMENT?

A. I am a Senior Research Consultant with the Acadian Consulting Group ("ACG"), a research and consulting firm that specializes in the analysis of regulatory, economic, financial, accounting, statistical, and public policy issues associated with regulated and energy industries. ACG is a Louisiana-registered partnership, formed in 1995, and is located in Baton Rouge, Louisiana.

Q. PLEASE DESCRIBE YOUR PROFESSIONAL QUALIFICATIONS.

A. I hold a Bachelor of Arts degree in Business Economics from Buena Vista University in Storm Lake, Iowa, and a Master of Arts degree in Economics from the University of Kansas in Lawrence, Kansas. I began my professional career with the Staff of the Kansas Corporation Commission in 2008 while in graduate school conducting analyses of topics related to energy and economy as a Research Assistant, eventually being promoted to a Research Analyst and later Senior Research Economist after graduation. I left the Kansas Corporation Commission to take a position with ACG in late 2011, where I have been promoted to positions of increasing responsibility since, including my current position which I started in mid-2021. Appendix A provides my professional resume, which includes a listing of my publications, presentations, pre-filed expert witness testimony, expert reports, and expert legislative testimony.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I have been retained by the Pennsylvania Office of Consumer Advocate ("OCA") to address matters related to the general rate case filed by Citizens' Electric Company of Lewisburg ("Citizens" or the "Company"). I specifically have been asked to review the Company's proposed Allocated Class Cost of Service Study ("ACOS") and rate design.

Q. ARE YOU SPONSORING ANY EXHIBITS?

A. Yes. I am sponsoring the following Exhibits MWD-1 (Citizens) through MWD-4 (Citizens).

- Exhibit MWD-1: Summary of Results of Company's Proposed ACOS
- Exhibit MWD-2: Summary of Results of Alternative ACOS
- Exhibit MWD-3: Summary of Company's Proposed Revenue Allocation
- Exhibit MWD-4: Summary of Results of Alternative Revenue Allocation

II. SUMMARY OF RECOMMENDATIONS

Q. WHAT ARE YOUR ACOS FINDINGS FOR CITIZENS'?

A. My alternative ACOS analyses shows that Citizens' incorrect classification of secondary-voltage distribution plant skews the allocation of costs and revenue responsibilities away from larger customers and onto residential and small commercial customers. I recommend the Commission rely on the results of my alternative ACOS as a fair and reasonable estimation of relative costs of service between Citizens' customer classes.

Q. WHAT IS YOUR RECOMMENDATION REGARDING CITIZENS' PROPOSED REVENUE DISTRIBUTION?

A. I recommend that the Commission adopt a more reasonable revenue distribution allocation method based on my alternative ACOS results that also limits the rate increase to the municipal lighting ("MBL") customer class to 1.25 times the overall system average increase. Under Citizens' proposed overall distribution revenue increase of 29.64 percent this reduces the revenue increase to this rate class to 37.05 percent, compared to the Company's proposed distribution rate increase of 75.0 percent.

Q. WHAT IS YOUR RECOMMENDATION REGARDING CITIZENS' PROPOSED RATE DESIGN FOR CUSTOMER CHARGES?

A. I recommend the Commission reject Citizens' proposed increases in customer charges because they disproportionately impact low-income customers and reduce customer incentives to reduce usage, contrary to public goals of promoting energy efficiency. Furthermore, Citizens' existing residential and small commercial customer charges are already higher than the regional average of peer investor-owned utilities, and the proposed increase would make the charges the highest of peers. Finally, a correct analysis of customer-related costs from Citizens' ACOS finds that all residential and commercial rate classes are currently recovering *all* customer-related costs through monthly customer charges.

III. ALLOCATED COST OF SERVICE STUDY

A. Introduction

Q. WHAT IS THE PURPOSE OF AN ACOS?

A. An ACOS is a modeling approach that reconciles utility costs and revenues across different customer classes. The goal of an ACOS is to evaluate the cost of providing service and revenue responsibility for each individual customer class. ACOS results are used to estimate class specific rates of return and can serve as a guidepost for class revenue responsibilities and ultimately rates.

Q. HOW IS AN ACOS PREPARED?

A. An ACOS utilizes a set of historic or projected cost information that is (1) functionalized, (2) classified, and (3) allocated. The functionalization process simply categorizes costs based upon the functions they serve within a utility's overall operations (i.e. production, transmission, and distribution). The classification process characterizes costs by type, including those that are (1) demand-related, (2) energy/commodity-related, or (3) customer-related. The last step of the process allocates each of these costs to a respective jurisdiction or customer class as appropriate.

Q. PLEASE EXPLAIN DEMAND-RELATED COSTS.

A. Demand-related costs are associated with meeting maximum electricity demands. At the distribution level, electric substations and line transformers are designed, in part, to meet the maximum customer demand requirements. The most common demand allocation factors used in an ACOS are those related to system Coincident Peaks ("CP") or Non-Coincident Peaks ("NCP"). At the production level, most power plants, also referred to as production plants or electric generation units ("EGU"), are typically viewed as being designed to serve both the energy/commodity and demand/capacity needs of

the utility. The exact degree of this split between energy and demand depends on the individual EGU in question and how that unit is dispatched with baseload units serving more of the utility's energy needs and peak units serving more of the utility's capacity or demand needs. Therefore, it is not uncommon to develop composite energy and demand allocators to allocate plant-in-service costs associated with a utility's generation fleet.

Q. HOW ARE ENERGY-RELATED COSTS DEFINED?

A. Energy-related costs are defined as those that tend to change with the amount or volume of electricity (i.e., kilowatt-hour ("kWh")) sold. Electric generation costs and high-voltage transmission lines, for instance, can be allocated, in part, based on some measure of electricity sales.

Q. WHAT ABOUT CUSTOMER-RELATED COSTS?

A. Customer-related costs are those associated with connecting customers to the distribution system, metering household or business usage, and performing a variety of other customer support functions.

Q. IS THIS A RELATIVELY SIMPLE PROCESS?

A. No. Some costs can be clearly identified and directly assigned to a function , while other costs are more ambiguous and difficult to assign. The primary challenge in conducting an ACOS is the treatment of what are known as "joint and common" costs. Given their shared or integrated nature, these joint and common costs can often be difficult to compartmentalize. Therefore, unique allocation factors are utilized in an ACOS to classify joint and common costs. The process of developing these cost allocation factors can become subjective and is often imbued with policy considerations.

Q. HOW DOES AN ACOS RELATE TO COMMONLY QUOTED ECONOMIC PRINCIPLES?

A. An ACOS is referred to as a "fully allocated cost study" since it allocates test year revenues, rate base, expenses, and depreciation to various jurisdictions and customer classes based upon a series of different allocation factors. The purpose of the ACOS is to develop cost responsibility estimates for each customer class, which in turn, can be used to develop rates. An ACOS is based upon a set of historic utility book costs that have accumulated over decades. Rates are, therefore, based upon historic average costs, whereas economic theory suggests that the most efficient form of pricing in perfectly competitive markets should be based upon marginal costs. However, regulated utilities do not operate in perfectly competitive markets and, by their very nature, are natural monopolies. Thus, reaching the ideal pricing formula outlined in economic theory is impossible since the nature of natural monopolies makes pricing in the presence of declining average costs, coupled with the presence of joint and common costs, difficult.

Q. ARE THERE ANY OTHER CONFOUNDING PROBLEMS THAT CAN ARISE WITH AN ACOS?

A. Yes. The problems listed above are confounded by the fact that cost information utilized in an ACOS is usually historic and static, or based on potentially inaccurate projections in the context of Fully Projected Future Test Years ("FPFTY"). These analytic deficiencies undermine many experts' cost causation/pricing claims. As a result, in regular practice there is no single correct answer that is revealed in an ACOS. It is often up to regulators to exercise an appropriate level of judgment regarding the nature of these costs, the results of the ACOS, and the implications both have in setting fair, just, and

reasonable rates. This is one of the reasons why many regulators use ACOS results as a "guide" in setting rates and do not consider themselves unnecessarily bound by the ACOS results.

Q. WHAT CONTROVERSIES ARISE IN THE ANALYSIS AND COMPARISON OF VARIOUS ACOS METHODOLOGIES?

A. The ACOS process is significantly different from the revenue requirement or cost of capital phase of a typical rate case. While the latter two processes focus on determining how much revenue will be recovered through rates, the ACOS process determines how those costs (revenue requirements) will be recovered through customer rates. The primary controversy with the evaluation of various ACOS results often rests with determining whether costs (revenue requirements) will be recovered by the relative customer share of each class, the peak load contributions of each customer class, or whether and how the approach will be tempered through the use of customer, peak, and off-peak usage considerations. Methodologies that are heavily skewed toward customer and peak considerations, for instance, can shift costs more than proportionally to relatively lower load-factor customers, such as residential and small commercial customers, and less costs to larger high load factor customer classes and off-peak customers. These approaches can also fail to capture the service being provided by the utility (i.e., electric service in this case), and how the value of that service varies by the amount purchased by different customer classes.

Q. PLEASE EXPLAIN THE BIAS IN METHODOLOGIES THAT ARE SKEWED TOWARD PEAK CONSIDERATIONS.

A. Residential and small commercial customer electricity loads are typically weather sensitive. On the other hand, larger industrial customers use electricity in processes that are generally not weather sensitive, and electric use thus tends not to cycle up and down, but rather runs on a more continuous basis. Because of this, daily and annual usage patterns for these two customer classes are significantly different. The peak loads for residential and small commercial customers tend to be more "peaked" than those for industrial customers, which are steadier and more evenly distributed across peak and non-peak hours. For example, an average residential customer may have relatively little electricity use during overnight hours and during weekday daytime working hours. Residential customers exhibit relatively significant use during early summer evening hours corresponding to returning home from work, and potentially during chilly early winter morning hours if the customer uses electric resistance heating. Similarly, small commercial customers see limited electricity use outside of workday hours. Thus, residential and small commercial customers tend to have relatively lower load factors than large industrial customers.

Q. PLEASE DEFINE "LOAD FACTOR."

A. A load factor is defined as the ratio of the average load in kilowatt hours supplied during a designated period to the peak or maximum load in kilowatts occurring in that period. The load factor is expressed as a percentage and may be derived by taking the energy used during a period and dividing it by the product of the maximum demand and the number of hours in the period. A system that is estimated to have a high load factor is often thought to be utilizing electricity more efficiently, since usage is consistent and does not swing significantly between average and peak periods. Conversely, systems

with low load factors must maintain idle capacity in order to meet the relatively large swings in load between average and peak periods.

Q. DOES A HIGH LOAD FACTOR INDICATE GREATER SYSTEM EFFICIENCY?

A. Yes, since a higher system load factor can be indicative of, or lead to better system resource utilization, other things being equal. However, it should be recognized that all utilities inherently have customers with different load profiles due to differences in how customers use electricity. Furthermore, the development of integrated wholesale bulk electricity transmission systems has allowed utilities to collectively diversify generation resources and individual system demands, which has reduced the impact of individual system load characteristics on generation needs in recent years. While rates should recognize and promote the efficient utilization of utility system resources, caution should be used in placing too much emphasis on this principle of rewarding high load factor industrial customers to the detriment of low load factor residential and small commercial customers.

Q. WHAT IMPACT DOES COST ALLOCATION HAVE ON REVENUE RECOVERY?

A. Higher use customers, such as industrial customers, are inherently more price sensitive than lower use customers due to the relative impact increases in rates can have on these customers' total utility bills and the margins of produced goods. These higher use industrial customers tend to have more energy supply alternatives, including fuel switching and self-generation, which is part of the reason why they are more price sensitive. These considerations can result in differences in revenue generation given the

differences in the price elasticities of demand (i.e., price sensitivities) for the two sets of customers (residential, industrial).

Q. EXPLAIN HOW SOME ACOS METHODS CAN BE BIASED AGAINST LOWER LOAD-FACTOR CUSTOMERS.

A. Utilities by their nature are capital intensive industries with high levels of capital expenditures required to develop systems to generate and transmit power to customers. Therefore, deciding the appropriate allocation of costs associated with utility capital investments (e.g., utility "plant in service") largely affects the cost of providing service. Utilities can often over-emphasize peak demand factors in allocating these large plant costs in order to assign more costs away from their price sensitive customers. Likewise, utilities can emphasize non-diversified single CP demands, NCP demands, and individual customer demands in allocating costs associated with transmission and distribution plant facilities to favor high-load factor customers relative to low-load factor customers. Finally, utilities can over-emphasize customer connection aspects of lower voltage distribution facilities to favor high-use customers relative to low-use customers.

B. Overview of Company's ACOS

Q. PLEASE DESCRIBE CITIZENS' ACOS APPROACH.

A. The Company states that it developed its ACOS with four goals in mind: (1) recognition of cost causality as opposed to value of service, (2) stability of results over time, (3) logical consistency and completeness, and (4) ease of implementation.[1] To this end the Company utilizes the traditional three-step approach to ACOS. First the Company functionalizes its costs to six separate functions: supply; transmission; sub-transmission;

[1] Direct Testimony of Howard S. Gorman at 15:2-9.

primary distribution; secondary distribution; and billing.[2] Second, the Company classifies these functionalized costs to two separate purposes: demand and customer costs.[3] Finally, the Company defines a series of individual allocators to allocate these functionalized and classified costs to individual rate classes.[4]

Q. PLEASE EXPLAIN HOW THE COMPANY CLASSIFIES ITS DISTRIBUTION PLANT INVESTMENTS.

A. The Company classifies all distribution plant investment costs as either customer- or demand-related, or a combination of these two factors.[5] The Company utilized what it refers to as a "zero-load analysis" to define a portion of secondary distribution system costs associated with utility poles (FERC Account 364), overhead conductors (FERC Account 365), underground conductors (FERC Account 366), underground conduit (FERC Account 367), and line transformers (FERC Account 368) as partially customer-related, while classifying all other non-customer-related distribution as fully demand-related.[6]

[2] Direct Testimony of Howard S. Gorman at 16:8-9, and Company Response to OCA-I-1, Attachment A.

[3] Direct Testimony of Howard S. Gorman at 16:9-10, and Company Response to OCA-I-1, Attachment A.

[4] Direct Testimony of Howard S. Gorman at 16:10-11, and Company Response to OCA-I-1, Attachment A.

[5] Company Response to OCA-I-1, Attachment A.

[6] Direct Testimony of Howard S. Gorman at 16:10-11, and Company Response to I&E-RE-1D, Attachment A.

Table 1: Summary of Results of Company's ACOS

	Total Citizens	Residential Service (RS)	Commercial and Industrial Service: Space Heating (SH)	Commercial and Industrial Service: General L&P (GLP-1)	Commercial and Industrial Service: General L&P (GLP-3)	Lighting Service: Municipal (MBL)	Lighting Service: Outdoor (OL)
Net Operating Income							
Total Operating Revenues	$ 6,159,008	$ 3,971,574	$ 8,889	$ 1,108,954	$ 927,024	$ 26,383	$116,184
Total Operating Expenses	5,908,628	3,997,072	7,448	912,930	840,465	55,471	95,242
Net Operating Income	**$ 250,380**	**$ (25,498)**	**$ 1,441**	**$ 196,024**	**$ 86,559**	**$ (29,088)**	**$ 20,942**
Total Rate Base	**$17,092,345**	**$11,451,271**	**$ 21,081**	**$ 2,564,908**	**$ 2,328,190**	**$282,749**	**$444,146**
Rate of Return on Rate Base	**1.46%**	**-0.22%**	**6.84%**	**7.64%**	**3.72%**	**-10.29%**	**4.72%**
Relative Rate of Return (RRO	**1.00**	**-0.15**	**4.67**	**5.22**	**2.54**	**-7.02**	**3.22**

Q. HAVE YOU EXAMINED THE COMPANY'S ACOS RESULTS?

A. Yes. Exhibit MWD-1 (Citizens), summarized in Table 1 above, presents the results of the Company's ACOS which estimates an overall FPFTY rate of return ("ROR") of current rates of 1.46 percent. Estimated individual class returns range from negative 10.29 percent for the municipal lighting or MBL class to 7.64 percent for the general light and power-1 ("GLP-1") class. The residential service ("RS") rate class is estimated by the Company to have achieved an ROR of negative 0.22 percent during the test year under current rates, which is negative 0.15 of the system average on a relative rate of return ("RROR") basis.

Q. DO YOU DISAGREE WITH ANY OF THE ASSUMPTIONS OR ALLOCATION FACTORS INCORPORATED IN THE COMPANY'S PROPOSED ACOS?

A. Yes. I disagree with the Company's reliance on the results of its zero-load analysis and minimum size analysis to classify secondary distribution plant assets as being partially customer-related. The Company's zero-load analysis for secondary distribution plant other than transformers and minimum size analysis for transformers are forms of what is referred to as a Minimum System Study ("MSS") that are not aligned with cost-causation.

C. Use of a "Minimum System Study" to Classify Distribution Plant Costs

Table 2: Summary of Results of Company's Zero-Load Analysis

FERC Account Description	Demand Allocation	Customer Allocation
364 Secondary Poles, Towers and Fixtures	19.31%	80.69%
365 Secondary Overhead Conductors and Devices	22.60%	77.40%
366 Secondary Underground Conduit	42.89%	57.11%
367 Secondary Underground Conductors and Devices	42.89%	57.11%
368 Secondary Line Transformers	64.15%	35.85%

Source: Company's Response to I&E-RE-1-D, Attachment A.

Q. PLEASE DESCRIBE HOW THE COMPANY CLASSIFIES THE CUSTOMER AND DEMAND COMPONENTS OF ITS SECONDARY-VOLTAGE DISTRIBUTION PLANT COSTS.

A. The Company's witness Mr. Gorman conducted a zero load analysis to determine the customer-related component of secondary-voltage distribution system costs included in FERC Account 364 – Overhead Electric Poles; FERC Account 365 – Overhead Conductors; FERC Account 366 – Underground Conductors; FERC Account 367 – Underground Conduits; and a minimum size analysis to determine the customer-related component of secondary-voltage transformer costs included in FERC Account 368 – Line Transformers.[7] Table 2 presents a summary of the results of the Company's zero load and minimum size analyses. The Company's zero load and minimum size analyses estimates customer-related classification from a low of 35.85 percent (FERC Account 368) to a high of 80.69 percent (FERC Account 364).[8]

[7] Direct Testimony of Howard S. Gorman at 16:10-11, and Company Response to I&E-RE-1D, Attachment A.

[8] Company Response to I&E-RE-1D, Attachment A.

Q. PLEASE DESCRIBE THE ZERO-LOAD ANALYSIS MR. GORMAN USES TO ESTIMATE THE CUSTOMER-RELATED PORTION OF UPSTREAM SECONDARY DISTRIBUTION PLANT OTHER THAN LINE TRANSFORMERS.

A. Mr. Gorman examined the total inventory of Citizens' poles, overhead conductors and underground conductors.[9] He then examined what appears to be the cost that would be required to replace this inventory based on recent workorders, separating these expenses into four categories: Labor, Overhead, Vehicle, and Materials.[10] All non-materials costs were viewed as labor-related (i.e. Labor, Overhead, and Vehicle expenses) and classified as customer-related with the balance being defined as demand-related.[11] As Mr. Gorman states in this proceeding, "The zero-load component of the Secondary system represents the cost of extending service to all customers, without regard to peak or average load, and is therefore customer-related."[12] Since this "zero-load component" has no load-carrying capacity, no adjustment to the demand allocators is proposed by Mr. Gorman.

Q. PLEASE DESCRIBE MR. GORMAN'S "MINIMUM SIZE ANALYSIS" FOR CLASSIFYING A PORTION OF LINE TRANSFORMERS AS CUSTOMER-RELATED.

A. Similar to his zero-load analysis, Mr. Gorman first examined the total inventory of Citizens' line transformers. He then claims he defined a minimum size transformer of 50 kilovolt amperes ("kVa") serving four customers, or 12.5 kVa per customer.[13] Finally, Mr.

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[9] *Id.*

[10] *Id.*

[11] Direct Testimony of Howard S. Gorman at 20:6-10.

[12] Direct Testimony of Howard S. Gorman at 20:10-12.

[13] Direct Testimony of Howard S. Gorman at 20:17-19.

Gorman multiplied this minimum size transformer cost by the number of line transformers on Citizens' system to arrive at the portion of total line transformer costs that he defines as customer-related.[14]

Q, DO YOU AGREE WITH MR. GORMAN'S ZERO-LOAD ANALYSIS FOR SECONDARY PLANT OTHER THAN TRASNFORMERS OR MINIMUM SIZE ANALYSIS FOR TRANSFORMERS?

A. No. As stated, both Mr. Gorman's zero-load analysis and minimum size analysis are forms of a MSS that are not aligned with cost-causation, which I explain more fully below, and I disagree with Mr. Gorman's reliance on the results of his zero-load analysis and minimum size analysis to classify secondary distribution plant assets as being partially customer-related.

Q. PLEASE EXPLAIN THE THEORETICAL BASIS FOR A "MINIMUM SYSTEM" STUDY OR MSS.

A. Such studies are often advocated by those holding the view that certain distribution plant investments are made to serve a dual-nature: one consisting of meeting system load requirements, the other being focused on customer interconnection or access that requires a customer-based allocation component. This minimum system component is determined through an MSS (referred to by Mr. Gorman in this proceeding as a "zero-load analysis") or a related "zero-intercept study."

Q. WHAT ARE MSS AND ZERO-INTERCEPT STUDIES?

[14] Direct Testimony of Howard S. Gorman at 20:16-23.

A. MSS and zero-intercept studies are cost allocation methodologies that attempt to estimate separate customer-related versus load-related costs. An MSS does this by estimating the hypothetical costs of developing a “minimum” system that only provides customers with connection to a utility’s electric distribution system but not a system sufficient to actually serve the customer’s electrical requirements. Likewise, a zero-intercept study utilizes regression analysis techniques to estimate the relationship between the electric demand requirements on a system and costs associated with installation of new distribution plant assets. Using these regression analyses, a zero-intercept study then calculates a hypothetical minimum cost by calculating the costs of the distribution plant assets given zero demand requirements.

Q. PLEASE DESCRIBE THE MECHANICS OF AN MSS.

A. It is argued that many distribution system assets can be classified as having both a customer and a demand component. For instance, distribution substations are built to serve customers but are often expanded to meet increases in customer loads. An MSS study attempts to separate the customer-related portion of total system costs from those associated with serving loads (or service volumes). An MSS study estimates the hypothetical costs of developing a minimum system to serve customers with no load. These calculations involve subjectivity since they use accounting and engineering analyses to develop assumptions about the minimum sizes and costs associated with various distribution system components, while still satisfying system requirements such as pole height and efficient conductor and transformer sizes. The costs associated with these “minimum” components are then added together to derive the total minimum costs associated with the hypothetical system with no energy usage. This estimate is then

divided by total actual system costs to approximate the customer-related share of overall distribution system costs.

Q. ARE THERE ANY THEORETICAL SHORTCOMINGS TO USING MSS AND ZERO-INTERCEPT STUDIES FOR CLASSIFICATION OF DISTRIBUTION PLANT ASSETS?

A. Yes. Both MSS and zero-intercept studies depend on deeply flawed counterfactual theoretical premises. MSS-based analyses deal in hypotheticals that do not exist in the real world, including the assumption that somehow there is an electric distribution system out there in the world that could or would be plausibly built to serve customers but not load. No such system exists, making the underlying assumptions and modeling of a "minimum system" difficult, if not impossible, to verify. Even if a minimum electric distribution system could be constructed in real life, it would still have the ability to service at least a portion of customers' loads, undermining this modeling approach's fundamental premise.

Q. DOES THE NARUC COST ALLOCATION MANUAL RECOGNIZE THESE CHALLENGES?

A. Yes. The National Association of Regulatory Utility Commissioners ("NARUC") Electric Cost Allocation Manual ("NARUC Manual") recognized this fundamental failing of MSS approaches in its discussion of the approach:

> Cost analysts disagree on how much of the demand costs should be allocated to customers when the minimum-size distribution method is used to classify distribution plant. When using this distribution method, the analyst must be aware that the minimum-size distribution equipment has a certain load-

carrying capability, which can be viewed as a demand-related cost.[15]

Q. WHAT ARE THE THEORETICAL FAILINGS OF ZERO-INTERCEPT BASED STUDIES?

A. A zero-intercept-based approach is simply a statistically based MSS approach and suffers, conceptually, from the same shortcomings. A zero-intercept analysis attempts to model an empirical relationship that does not exist. One should recognize that the argument that electric distribution costs are related to the number of customers on a utility's system is not a new argument, and the academic literature in utility regulation has questioned for quite some time the use of both MSS and zero-intercept studies.

Q. HOW HAS THE ACADEMIC LITERATURE IN UTILITY REGULATION QUESTIONED THE USE OF MSS AND ZERO-INTERCEPT STUDIES?

A. Dr. James Bonbright, in his seminal work on public utility regulation, published originally in the 1970s, raises a number of questions about the use of MSS and zero-intercept methodologies in classifying costs. Dr. Bonbright's primary concern was the lack of empirical support in the academic literature for a causal relationship between distribution system costs and the number of customers. The true driving factors of utility distribution system costs are much more complicated and depend on a host of other factors, such as the size of a service territory and the population density within. The incremental cost of constructing an appropriate distribution system to serve an additional customer within an urban area with existing nearby infrastructure is substantially less than the cost to extend an existing utility system by potentially miles to serve an additional

[15] Electric Utility Cost Allocation Manual (January 1992), NARUC, p. 95.

customer located in a rural area, a fact inherently ignored by MSS and zero-intercept methodologies:

> …the annual costs of this phantom, minimum-sized distribution system are treated as customer costs and are deducted from the annual costs of the existing system, only the balance being included among those demand-related costs to be mentioned in the following section. Their [minimum distribution costs] inclusion among the customer costs is defended on the ground that, since they vary directly with the area of the distribution system (or else with the lengths of the distribution lines, depending on the type of distribution system), they therefore vary directly with the number of customers. Alternatively, they are calculated by the "zero-intercept" method whereby regression equations are run relating cost to various sizes of equipment and eventually solving for the cost of a zero-sized system (Sterzinger, 1981).
>
> What this last-named cost imputation overlooks, of course, is the very weak correlation between the area (or the mileage) of a distribution system and the number of customers served by this system. For it makes no allowance for the density factor (customers per linear mile or per square mile). Our casual empiricism is supported by a more systematic regression analysis in (Lessels, 1980) where no statistical association was found between distribution costs and number of customers. Thus, if the company's entire service area stays fixed, an increase in number of customers does not necessarily betoken any increase whatever in the costs of a minimum-sized distribution system.[16]

Q. WHAT WAS DR. BONBRIGHT'S CONCLUSION REGARDING THE USE OF MSS AND ZERO-INTERCEPT STUDIES?

A. Dr. Bonbright found that attempts to classify costs associated with a minimum-sized distribution system, whether determined through the use of an MSS or a zero-intercept study, as something other than demand-related as potentially of merit.

[16] James C. Bonbright, *et al*. Principles of Public Utility Rates. 1988 Edition. Arlington, VA: Public Utilities Reports, Inc., p. 491.

However, he ultimately concluded that classifying these costs as customer-related as the Company has done in the current proceeding is "clearly indefensible,"[17] due to the lack of a relationship between changes in the number of customers on a utility system and its distribution costs.

Table 3: Correlation of Customers and Distribution Network Additions

Year	Change in Average Number of Customers	Net Distribution Plant Addition	Poles, Towers, and Fixtures Additions	Overhead Conductors Additions	Underground Conduits Additions	Underground Conductors Additions	Line Transformers Additions
		($000)					
2008	55	$ 609	$ 108	$ 280	$ -	$ 148	$ 74
2009	40	498	25	338	-	57	78
2010	22	591	96	355	-	83	57
2011	7	372	102	157	-	47	66
2012	(2)	489	112	203	-	88	86
2013	29	505	72	254	-	116	63
2014	30	410	66	181	-	77	86
2015	26	661	98	307	-	188	67
2016	34	780	137	377	-	161	104
2017	62	493	79	211	-	150	53
2018	40	811	104	477	-	187	43
2019	3	649	207	317	-	90	35
2020	(8)	589	136	320	-	102	31
2021	26	526	137	278	-	82	30
2022	30	803	122	422	-	167	92
2023	30	753	141	338	-	99	175
2024	51	994	312	397	-	177	108
Correlation Coefficients		0.3062	-0.0338	0.2279	N/A	0.5121	0.2466
P-Value		0.2320	0.8975	0.3789	N/A	0.0356	0.3400
Significant at 95% Level		Not Significant	Not Significant	Not Significant	N/A	Significant	Not Significant

Source: Company's Annual Reports

Q. HAVE YOU QUANTITATIVELY ASSESSED THE HISTORIC CORRELATION BETWEEN INCREASES IN COMPANY DISTRIBUTION PLANT AND INCREASED NUMBER OF CUSTOMERS?

A. Yes. Table 3 examines trends between changes in average number of customers on the Company's system and distribution plant accounts 364-368 for the years 2008

[17] *Id* at 492.

through 2024. This analysis finds that additions to the relevant distribution plant accounts are not highly correlated with changes in the Company's average number of customers. Specifically, I estimate the correlation coefficient for the individual FERC accounts in question to range from negative 0.0338 to positive 0.5121, and I estimate the correlation coefficient of these distribution plant accounts in total to be 0.3062. Overall, this demonstrates very weak correlation, as observed by Dr. Bonbright decades ago.

Q. HAVE OTHER JURISDICTIONS REJECTED THE USE OF AN MSS?

A. Yes. In 2021, the Michigan Public Service Commission rejected a proposal that Consumers Energy be required to submit an MSS in its next rate case.[18] Likewise, in 2010, the Rhode Island Public Utilities Commission rejected a request that it require the use of a minimum system study for Narragansett Electric Company D/B/A National Grid.[19]

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE RELIANCE ON AN MSS TO ALLOCATE COSTS ASSOCIATED WITH DISTRIBUTION PLANT ASSETS?

A. I recommend the Commission reject the Company's proposed MSS approaches in the classification of secondary-voltage distribution plant costs included in FERC Accounts 364-368. MSS and related zero-intercept approaches are fundamentally flawed and provide little to no value as to the just and reasonable setting of rates. Research has shown these methods are flawed, and some state regulatory commissions have gone so far as to expressly reject their use. Further, while MSS is used by some utilities, it is not

[18] In the Matter of the Application of Consumers Energy Co. for Authority to Increase its Rates for the Generation and Distribution of Electricity and for Other Relief, Case No. U-20963, Order, dated December 22, 2021.

[19] In re: the Application of The Narragansett Elec. Co. D/B/A National Grid For Approval of A Change in Electric Base Distribution Rates, Docket No. 4065, Decision and Order, dated April 29, 2010.

commonly used by all utilities. Thus, I recommend the Commission appropriately classify assets included in the relevant distribution plant accounts as 100 percent demand-related.

Q. DO YOU HAVE ANY OTHER QUALITATIVE COMMENTS ABOUT MR. GORMAN'S ANALYSIS TO CLASSIFY SECONDARY DISTRIBUTION PLANT BESIDES LINE TRANSFORMERS AS PARTIALLY CUSTOMER-RELATED?

A. Yes. As explained before, there is no direct relationship between the number of customers and the cost of these secondary distribution plant. For example, when a distribution line is upgraded, the costs of doing so are integrated and capitalized. If a new conductor is added, or new poles installed, there is no rationale to separating out the costs of labor, vehicle, and overhead as customer-related while only the costs of the materials of the poles and the conductor are related to demand. Without the poles and the conductor there would be no distribution line upgrade, and that upgrade was no doubt required because the expected future coincident demand to be imposed on those facilities required the upgrade, undermining the concept of attempting to identify a 'minimum' cost of interconnection since all of these costs are based on coincident demand considerations. Mr. Gorman's separation of these installation costs into customer- and demand-related is artificial and merely has the effect of shifting cost responsibility to low-load factor customer classes with numerous small customers.

Q. DO YOU HAVE ANY OTHER QUALITATIVE COMMENTS ABOUT MR. GORMAN'S ANALYSIS TO CLASSIFY LINE TRANSFORMERS AS PARTIALLY CUSTOMER-RELATED?

A. Yes. Similar to my observation concerning other secondary distribution network costs, upgrades to transformer capacity will depend upon the coincident demand that

must be met by the local distribution systems. The reasons for making transformer investments is the need to meet these local coincident loads. Again, this undermines the concept of attempting to identify a 'minimum' cost since even this so-called minimum size transformer has significant load-carrying capability and its investment is made in recognition of these demand considerations and not simply to connect the customer to the system. For all these reasons, Mr. Gorman's classification of these costs should be rejected and 100 percent of these costs should be classified as demand-related.

D. Summary of ACOS Findings

Table 4: Summary of Results of Alternative ACOS

	Total Citizens	Residential Service (RS)	Commercial and Industrial Service			Lighting Service	
			Space Heating (SH)	General L&P (GLP-1)	General L&P (GLP-3)	Municipal (MBL)	Outdoor (OL)
Net Operating Income							
Total Operating Revenues	$ 6,159,008	$ 3,971,574	$ 8,889	$ 1,108,954	$ 927,024	$ 26,383	$116,184
Total Operating Expenses	5,908,629	3,914,697	8,329	918,444	917,496	54,960	94,703
Net Operating Income	**$ 250,379**	**$ 56,877**	**$ 560**	**$ 190,510**	**$ 9,528**	**$ (28,577)**	**$ 21,481**
Total Rate Base	**$17,092,346**	**$11,155,747**	**$ 24,263**	**$ 2,585,172**	**$ 2,606,253**	**$280,051**	**$440,860**
Rate of Return on Rate Base	**1.46%**	**0.51%**	**2.31%**	**7.37%**	**0.37%**	**-10.20%**	**4.87%**
Relative Rate of Return (RRO	**1.00**	**0.35**	**1.58**	**5.03**	**0.25**	**-6.97**	**3.33**

Q. PLEASE SUMMARIZE YOUR ACOS FINDINGS.

A. Exhibit MWD-2 (Citizens), summarized in Table 4 above, presents the results of my alternative ACOS which appropriately classifies costs associated with secondary-voltage distribution plant accounts included in FERC Accounts 364-368 as 100 percent demand-related. My alternative ACOS show that the Company's incorrect classification of production plant and secondary-voltage distribution plant assets skews the allocation of costs and revenue responsibilities away from larger customers and onto residential customers and small commercial customers. I recommend the Commission rely on the results of my alternative ACOS as a fair and reasonable estimation of the relative costs of service between Company customer classes.

Table 5: Comparison of ACOS Results

	Total Citizens	Residential Service (RS)	Commercial and Industrial Service			Lighting Service	
			Space Heating (SH)	General L&P (GLP-1)	General L&P (GLP-3)	Municipal (MBL)	Outdoor (OL)
Citizens' Proposed							
Rate of Return on Rate Base	1.46%	-0.22%	6.84%	7.64%	3.72%	-10.29%	4.72%
Relative Rate of Return	1.00	-0.15	4.68	5.23	2.55	-7.05	3.23
OCA Alterantive							
Rate of Return on Rate Base	1.46%	0.51%	2.31%	7.37%	0.37%	-10.20%	4.87%
Relative Rate of Return	1.00	0.35	1.58	5.05	0.25	-6.99	3.34

IV. REVENUE DISTRIBUTION

Q. PLEASE EXPLAIN THE PURPOSE OF THE REVENUE DISTRIBUTION PROCESS IN SETTING RATES.

A. The revenue distribution process allocates a utility's overall revenue deficiency across customer classes, which in turn, is used to establish a new set of retail rates. The revenue distribution process often uses the results from the ACOS as its starting point, but not necessarily as its ending point. Class-specific revenue responsibilities are established by allocating the system-wide revenue deficiency to classes that are under-earning, relative to their estimated ROR, and assigning, at least in theory, revenue decreases to those classes that are over-earning relative to their ACOS-estimated class returns. The final class revenue responsibilities are then used, in conjunction with each class's billing determinants, to determine rates. In summary, the revenue distribution process can be thought of as the initial step taken to establish rates.

Q. DOES THE REVENUE DISTRIBUTION PROCESS INCLUDE ANY POLICY CONSIDERATIONS?

A. Yes. Allocating the overall system-wide revenue deficiency entirely on a full cost of service basis can result in a very significant and adverse rate impact for under-earning classes. Given this, regulators often determine the revenue responsibilities assigned to

various customer classes by considering a set of generally accepted ratemaking principles.

Q. WHAT ARE THOSE GENERALLY ACCEPTED RATEMAKING PRINCIPLES?

A. There are several generally accepted rate-making principles used in utility regulation that include:

1) Rates should be fair, just, and reasonable, and not unduly discriminatory.

2) To the extent possible, gradualism should be used to protect customers from rate shock.

3) Rate continuity should be maintained.

4) Rates should be informed by costs, but class cost of service results need not be the only factor used in rate development.

5) Rates should be understandable to customers.

Q. HOW ARE THE ABOVE PRINCIPLES APPLIED IN DEVELOPING RATES FOR A REGULATED UTILITY?

A. It is important to consider all of the ratemaking principles I reference above. However, any principle's relative weight can change depending upon the importance of certain policy goals. Rate design should strike a balance between policy goals and resulting rates that are fair, just, and reasonable. There is no pre-set or universally accepted formula for developing rates or rate design, and, as a result, sound judgment is necessary to formulate a rate design that meets these objectives.

Table 6: Summary of Company's Proposed Revenue Allocation

	Total Citizens	Residential Service (RS)	Commercial and Industrial Service: Space Heating (SH)	Commercial and Industrial Service: General L&P (GLP-1)	Commercial and Industrial Service: General L&P (GLP-3)	Lighting Service: Municipal (MBL)	Lighting Service: Outdoor (OL)
Allocated Cost of Service Results							
Rate of Return	1.46%	-0.22%	6.84%	7.64%	3.72%	-10.29%	4.72%
Relative Rate of Return	1.00	-0.15	4.68	5.23	2.55	-7.05	3.23
Proposed Revenue Allocation							
Current Distribution Revenues	$ 6,055,143	$ 3,903,746	$ 8,741	$ 1,092,138	$ 909,143	$ 26,151	$115,224
Proposed Distribution Revenue Increase	1,794,525	1,244,862	2,078	250,793	243,980	19,613	33,199
Proposed Distribution Revenues	**$ 7,849,668**	**$ 5,148,608**	**$ 10,819**	**$ 1,342,931**	**$ 1,153,123**	**$ 45,764**	**$148,423**
Proposed Revenue Change	**29.64%**	**31.89%**	**23.77%**	**22.96%**	**26.84%**	**75.00%**	**28.81%**
Relative Proposed Revenue Increase	**1.00**	**1.08**	**0.80**	**0.77**	**0.91**	**2.53**	**0.97**

Q. PLEASE EXPLAIN THE COMPANY'S APPROACH TO REVENUE DISTRIBUTION.

A. The Company states that cost of service is just one consideration in developing its proposed revenue allocation. Specifically, while the Company proposes to move each class closer to cost of service, it does so with an objective of mitigating extreme rate impacts on rate classes and on customer subgroups.[20] Exhibit MWD-3 (Citizens), summarized in Table 6 above, presents the Company's estimated current class RROR and its proposed revenue distribution.

Q. WHAT DO YOU MEAN BY RROR?

A. The RROR effectively standardizes the class-specific ROR estimated by an ACOS to the overall system average. In other words, it divides the estimated class ROR by the estimated system ROR. For instance, assume that the residential class is earning a class-specific eight percent ROR, and further assume that the system-wide average ROR estimated by the same ACOS is also eight percent. The residential class, in this example, can be said to be earning a 1.0 RROR if the estimated ROR is the same as the overall system (*i.e.*, eight percent divided by eight percent equals 1.0). Put another way, any class earning a 1.0 RROR can be said to be making its full contribution to the system's overall ROR (*i.e.*, there is no cross-subsidy). A RROR that is greater than 1.0 indicates that a particular class is contributing more than the system average contribution to the Company's overall return. Likewise, a class that earns a RROR less than 1.0 but greater than zero can be said to be making a less-than-average contribution to the overall system.

[20] Direct Testimony of Howard S. Gorman at 28:10-12.

Q. DO YOU AGREE THAT A CLASS RROR LESS THAN 1.0 IS PROBLEMATIC OR INEQUITABLE?

A. Not necessarily. Consistent with the ratemaking principles identified above, there may be policy reasons to support a result that reflects a cross-subsidization. For example, the presence and/or continuation of a RROR below 1.0 could be the result of a prior agreed-upon rate freeze that prevents class rates from increasing to correct a revenue deficiency (relative to cost of service). In this example, the presence of a RROR below 1.0 is simply a function of a prior policy decision, not necessarily the result of some arbitrary or intentionally designed unreasonable inequity.

Q. WHAT ARE THE CLASS RATE INCREASES UNDER THE COMPANY'S PROPOSED REVENUE DISTRIBUTION?

A. The Company proposes to increase base rates by 29.64 percent on a system-wide average basis. Under the Company's proposal individual classes would receive increases ranging from a 22.96 percent increase for GLP-1 customers to as high as a 75.0 percent for the MBL customers. This proposed increase to MBL customers is equal to more than 2.5 times the overall system average increase of 29.64 percent.

Q. DO YOU AGREE WITH THE COMPANY'S PROPOSED REVENUE DISTRIBUTIONS?

A. No. The Company's proposed revenue distributions suffer from two deficiencies. First, the Company's proposal is based on the results of a faulty ACOS that overstates the extent of any current subsidy from commercial and industrial customers to residential customers. Second, the Company's proposed increase to the MBL customer class is inconsistent with the principles of gradualism.

Table 7: Summary of Alternative Proposed Revenue Allocation

	Total Citizens	Residential Service (RS)	Commercial and Industrial Service: Space Heating (SH)	Commercial and Industrial Service: General L&P (GLP-1)	Commercial and Industrial Service: General L&P (GLP-3)	Lighting Service: Municipal (MBL)	Lighting Service: Outdoor (OL)
Allocated Cost of Service Results							
Rate of Return	1.46%	0.35%	2.31%	7.37%	0.37%	-10.20%	4.87%
Relative Rate of Return	1.00	0.24	1.58	5.05	0.25	-6.99	3.34
Proposed Revenue Allocation							
Current Distribution Revenues	$ 6,055,143	$ 3,903,746	$ 8,741	$ 1,092,138	$ 909,143	$ 26,151	$115,224
Proposed Distribution Revenue Increase	1,794,524	1,210,041	2,532	255,316	283,887	9,688	33,060
Proposed Distribution Revenues	**$ 7,849,667**	**$ 5,113,787**	**$ 11,273**	**$ 1,347,454**	**$ 1,193,030**	**$ 35,839**	**$148,284**
Proposed Revenue Change	**29.64%**	**31.00%**	**28.97%**	**23.38%**	**31.23%**	**37.05%**	**28.69%**
Relative Proposed Revenue Increase	**1.00**	**1.05**	**0.98**	**0.79**	**1.05**	**1.25**	**0.97**

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE COMPANY'S PROPOSED REVENUE DISTRIBUTION?

A. I recommend that the Commission adopt a more reasonable revenue distribution allocation method based on my alternative ACOS results that also limits the rate increase to the MBL customer class to 1.25 times the overall system average increase. Under the Company's proposed overall distribution revenue increase of 29.64 percent this reduces the revenue increase to this rate class to 37.05 percent, compared to the Company's proposed distribution rate increase of 75.0 percent.

Table 8: Comparison of Class Revenue Allocations

	Total Citizens	Residential Service (RS)	Commercial and Industrial Service: Space Heating (SH)	Commercial and Industrial Service: General L&P (GLP-1)	Commercial and Industrial Service: General L&P (GLP-3)	Lighting Service: Municipal (MBL)	Lighting Service: Outdoor (OL)
Citizens' Proposed							
Distribution Revenue Increase	$ 1,794,525	$ 1,244,862	$ 2,078	$ 250,793	$ 243,980	$ 19,613	$ 33,199
Percentage Increase	29.64%	31.89%	23.77%	22.96%	26.84%	75.00%	28.81%
OCA Alterantive							
Distribution Revenue Increase	$ 1,794,524	$ 1,210,041	$ 2,532	$ 255,316	$ 283,887	$ 9,688	$ 33,060
Percentage Increase	29.64%	31.00%	28.96%	23.38%	31.23%	37.05%	28.69%

Q. HAVE YOU PREPARED A SUMMARY OF THE EFFECTS OF YOUR PROPOSED REVENUE DISTRIBUTION?

A. Yes. Exhibit MWD-4 (Citizens) presents an illustrative summary of the effects of my proposed revenue allocation at the Company's proposed revenue requirement

increase. My proposed revenue distribution would increase base rates for the residential class by 31.00 percent, compared to the Company's proposal, which would increase such rates by 31.89 percent.

V. RATE DESIGN

Table 9: Summary of Company's Proposed Customer Charges

Rate Schedule	Current Charge	Proposed Charge	Percent Increase
Schedule RS - Residential Service	$13.10	$16.50	26.0%
Schedule SH - Space Heating	$20.19	$24.00	18.9%
Schedule GLP-1 - General Light and Power Service	$16.00	$21.00	31.3%
Schedule GLP-3 - General Light and Power Service	$55.00	$100.00	81.8%

Source: Company's Response to I&E-RE-1-D, Attachment A

Q. PLEASE DISCUSS THE COMPANY'S PROPOSED CUSTOMER CHARGE INCREASES.

A. As summarized by Table 9, the Company is proposing to increase the monthly customer charges for all rate classes. This includes a proposed increase in Residential Service ("RS") customer charge from $13.10 to $16.50 per month, representing a 26 percent increase. Likewise, the Company proposes to increase the commercial Space Heating ("SH") monthly customer charge from $16.00 to $21.00 per month, representing a 31 percent increase.

Table 10: Survey of Regional Customer Charges

Company	State	Residential Customer Charge ($/month)	Commercial Customer Charge ($/month)
Citizens Electric Company (Current)	**PA**	**$ 13.10**	**$ 16.00**
Citizens Electric Company (Proposed)	**PA**	**$ 16.50**	**$ 21.00**
Black Diamond Power Company	WV	8.00	10.12
Kentucky Utilities Company	VA	12.00	30.00
Pennsylvania Electric Company	NY	8.50	10.50
Pike County Light & Power Company	PA	8.80	17.26
Rockland Electric Company	NJ	5.75	16.00
The Toledo Edison Company	OH	4.00	7.00
UGI Utilities, Inc.	PA	10.75	17.00
Wellsborough Electric Company	PA	12.00	12.22
Wheeling Power Company	WV	12.50	15.00
Peer Group Average		**$ 9.14**	**$ 15.01**

Source: Utility Tariffs

Q. HAVE YOU COMPARED THE COMPANY'S PROPOSED RESIDENTIAL CUSTOMER CHARGES TO OTHER REGIONAL ELECTRIC UTILITIES?

A. Yes, and this analysis is presented in Table 10, which surveys current residential and small commercial customer charges among other regional electric utility companies. The analysis shows that the Company's current residential customer charge of $13.10 per month is the highest in the region out of the nine electric utility companies included in the survey. The average across all regional peers is $9.14, which is lower than the Company's current rate and significantly lower than the proposed customer charge of $16.50 per month. Likewise, the Company's proposed increase in SH customer charge to $21.00 per month would be the second highest in the region, and its current SH customer charge of $16.00 per month is higher than the regional average of $15.01 per month.

Q. WHAT IS THE BASIS OF THE COMPANY'S PROPOSED CUSTOMER CHARGE INCREASES?

A. The Company provides information supporting a claim that its ACOS supports a $36.56 monthly residential customer charge.[21] Likewise, the Company provides information supporting a claim that its ACOS supports a $40.94 monthly SH customer charge.[22]

Q. DO YOU AGREE WITH THE MANNER IN WHICH THE COMPANY MADE THESE CALCULATIONS?

A. No. The Company's analysis significantly overstates the cost directly attributable to residential customers. Specifically, it includes secondary distribution costs as customer-related based on its flawed zero-load analysis and minimum size analysis allocations, as discussed earlier.

Table 11: Analysis of Company Customer-Related Costs

Line No.	Description	Residential Service (RS)	Commercial and Industrial Service: Space Heating (SH)	General L&P (GLP-1)	General L&P (GLP-3)
1	Customer-Related Costs per Company's ACOS				
2	Class Functionalized Customer Billing Expenses	$939,683	$ 529	$ 199,286	$ 23,169
3	Number of Bills	72,612	36	13,644	504
4	**Monthly Customer-Related Costs/Customer**	**$ 12.94**	**$ 14.68**	**$ 14.61**	**$ 45.97**
5	Customer Charge Revenue at Current Rates				
6	Customer Charge Revenue at Current Rates	$951,217	$ 727	$ 218,304	$ 27,720
7	Number of Bills	72,612	36	13,644	504
8	**Monthly Customer Charge Revenue/Customer**	**$ 13.10**	**$ 20.19**	**$ 16.00**	**$ 55.00**
9	**Relationship of Customer Charge Revenues to Customer-Related Costs**	**101.23%**	**137.52%**	**109.54%**	**119.64%**

Source: Company's Response to OCA-I-1, Attachment A (Schedule E)

Q. HAVE YOU PREPARE AN ANALYSIS OF COSTS COMMONLY ASSOCIATED WITH CUSTOMER CHARGES?

[21] Direct Testimony of Howard Gorman, Exhibit HSG-1, Schedule E-1B.

[22] *Id.*

A. Yes. That analysis is provided in Table 11. "Customer-related" expense accounts are those typically allocated on the basis of customers and can include: removing and setting meters; maintenance of meters; services expense; maintenance of service drops; meter reading expense; dispatch applications and orders; customer records and collections; customer billing and accounting; customer service and information; and sales expense. These costs can also include the depreciation expense associated with the service drop and meter plant accounts and property taxes, as well as the carrying charges (at the Company's requested rate of return) for the customer portion of services investment and 100 percent of the meters investment.

Q. HOW DO THE COMPANY'S CUSTOMER CHARGE REVENUES COMPARE WITH THE RESULTS OF YOUR ANALYSIS?

A. The Company's current customer charge revenue associated with the residential class is more than 101 percent of the class' customer-related cost responsibilities. Likewise, the Company's current customer charge revenue associated with the SH class is 137.5 percent of the class' customer-related cost responsibilities.

Q. DO THESE RESULTS INDICATE ANY PRESSING NEED TO INCREASE MONTHLY CUSTOMER CHARGE RATES?

A. No. All Citizens' residential and commercial service rate classes currently cover *all* of their customer-related costs through monthly customer charges. The lowest, the residential class, still recovers more than 101 percent of its customer-related costs through its monthly customer charge.

Q. IS THE COMPANY'S PROPOSAL TO INCREASE THE CUSTOMER CHARGE CONSISTENT WITH PROMOTING ENERGY EFFICIENCY AND CONSERVATION?

A. No. The Company's rate design proposal is inconsistent with energy efficiency, since it reduces economic incentives for ratepayers to control their monthly utility bills through energy efficiency and conservation efforts, because only the variable component of bills is avoidable.

Q. HAVE OTHER REGULATORS RECOGNIZED THE NEGATIVE IMPACTS THAT CUSTOMER CHARGE INCREASES CAN HAVE FOR ENERGY EFFICIENCY?

A. Yes. In rejecting a request by Baltimore Gas and Electric ("BGE") to increase customer charges as part of a larger rate design proposal, the Maryland Public Service Commission ("MPSC") recognized the need to allow customers the opportunity to control their monthly bills by reducing energy usage.

> Even though this issue was virtually uncontested by the parties, we find we must reject Staff's proposal to increase the fixed customer charge from $7.50 to $8.36. Based on the reasoning that ratepayers should be offered the opportunity to control their monthly bills to some degree by controlling their energy usage, we instead adopt the Company's proposal to achieve the entire revenue requirement increase through volumetric and demand charges. This approach also is consistent with and supports our EmPOWER Maryland goals.[23]

Q. CAN YOU POINT TO ANY OTHER REGULATORY EXAMPLES?

A. Yes. The Montana Public Service Commission ("MT PSC") addressed this issue in evaluating, and rejecting, a proposal by Energy West Montana to eliminate volumetric charges and only have one fixed monthly customer charge (known as a "straight-fixed variable" or "SFV" rate design):

[23] Maryland Public Service Commission Case No. 9299, In the Matter of the Application of Baltimore Gas and Electric Company for Adjustment in its Electric and Gas Base Rates (*"Case No. 9299"*). Order No. 85374 at p. 99, rel. February 22, 2013.

> The Commission agrees that most distribution costs are not avoidable, and that volumetric distribution charges may encourage conservation actions that, all other things being equal, reduce the utility's embedded cost recovery between rate cases and contribute to future rate increases.
>
> …
>
> The Commission agrees that an SFV rate design is a clean and administratively inexpensive way to decouple revenue from volume. An often-cited public policy justification for revenue decoupling is to remove the volume disincentive for cost-effective conservation investment by a gas distribution company, which through SFV and other decoupling methods is rendered indifferent to the volume of gas consumed. Yet, SFV rates decouple revenue at the cost of decreasing returns to conservation investment by customers. For this reason the net conservation benefit of revenue decoupling via SFV rates is not clear, and may be negative.[24]

Q. HAVE ANY REGULATORY RESEARCH INSTITUTES ADDRESSED THE ISSUE OF THE RELATIONSHIP BETWEEN HIGH CUSTOMER CHARGES AND ENERGY EFFICIENCY?

A. Yes. A research document presented for consideration by the membership of NARUC also notes that extreme increases in customer charges, that typically happen under SFV rate design proposals, are problematic because of its effects on customer incentives to conserve energy:

> **Straight-Fixed Variable Rate Design.** This mechanism eliminates all variable distribution charges and costs are recovered through a fixed delivery services charge or an increase in the fixed customer charge alone. With this approach, it is assumed that a utility's revenues would be unaffected by changes in sales levels if all its overhead or fixed costs are recovered in the fixed portion of customers' bills. <u>This approach has been criticized for having the unintended effect of reducing customers' incentive to use less</u>

[24] In The Matter Of Energy West Montana, Application To Establish Increased Service Rates In Its Great Falls, Cascade, And West Yellowstone Service Areas, Montana Public Service Commission, Docket No. D2010.9.90, Order No, 7132c, at 29–30, rel. November 17, 2011.

> electricity or gas by eliminating their volumetric charges and billing a fixed monthly rate, regardless of how much customers consume.[25]

Q. HAS ANY NATIONAL PUBLIC POLICY ANALYSIS NOTED THE EFFICIENCY DISINCENTIVES ASSOCIATED WITH HIGH CUSTOMER CHARGES?

A. Yes. The National Action Plan for Energy Efficiency ("NAPEE"), a joint venture of the U.S. Department of Energy and U.S. Environmental Protection Agency, published a whitepaper on various rate design effects on encouraging energy efficient behaviors. The NAPEE postulated that rate designs over-emphasizing customer charges, like SFV, can deter or weaken the economic signals sent to customers to change their energy usage behavior and make investments in energy efficiency devices:

> Because [SFV] tends to shift costs out of volumetric charges, it tends to reduce customers' efficiency incentive, because the marginal price of additional consumption is reduced. While SFV rates are being considered to better reflect the utility's costs behind the rate, these rates do not encourage customers to change energy usage behavior or invest in efficiency technologies. Such customer disincentives persist even when SFV rates are applied to individual components of the bill, such as charges for distribution service.[26]

Q. SHOULD THE COMMISSION BE MINDFUL OF THE EFFECT OF THE COMPANY'S PROPOSED RATE DESIGN ON LOW-USE RESIDENTIAL CUSTOMERS?

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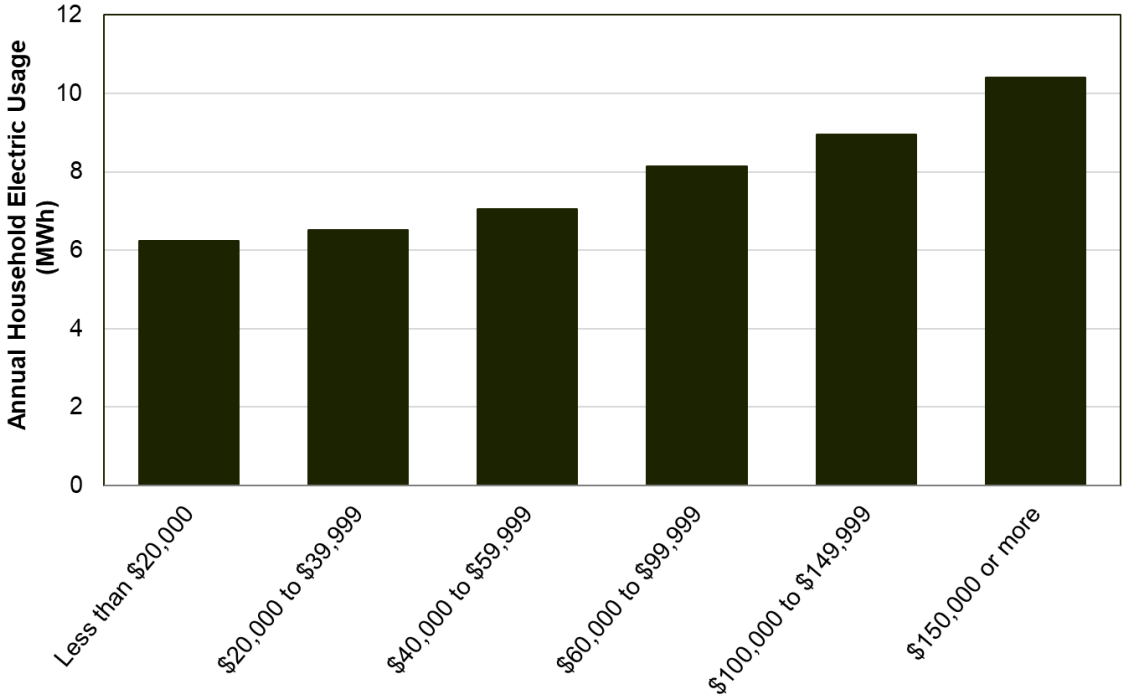
[25] "Decoupling for Electric & Gas Utilities: Frequently Asked Questions (FAQ)" Grants & Research Department, National Association of Regulatory Utility Commissioners, at 5 (Sept. 2007) (emphasis added).

[26] Customer Incentives for Energy Efficiency Through Electric and Natural Gas Rate Design, National Action Plan for Energy Efficiency at 13-14, prepared by William Prindle, ICF International, Inc. (Sept. 2009) (emphasis added).

A. Yes. There are numerous studies in the academic literature supporting the hypothesis that electricity is a "normal good."[27] That is, the consumption of electricity is directly correlated with household income level, meaning that higher-use electrical customers are typically higher income individuals and lower-use electrical customers are typically lower income individuals. These are important factual considerations the Commission should bear in mind.

Figure 1: Analysis of Electricity Usage and Household Income



Source: EIA 2020 Residential Energy Consumption Survey

[27] *See*, Alberini, A., W. Gans, D. Velez-Lopez. 2011, "Residential consumption of gas and electricity in the U.S.: The role of prices and income," Energy Economics 33, 870-881; Bernard, J., D. Bolduc, N. Yameogo, 2011, "A pseudo-panel data model of household electricity demand," Resource and Energy Economics 33(1), 315-325; Dax, P. 1987, "Estimation of Income Elasticity from Cross-Section Data," Applied Economics 19 (11), 1471-1482; Fell, H., S. Li, A. Paul. 2010, "A New Look at Residential Electricity Demand Using Household Expenditure Data," RFF DP 10-57; Fullerton, T. D. Juarez, A. Walke. 2012, "Residential Electricity Consumption in Seattle," Energy Economics; Reiss. P.C., and M. W. White, 2005, "Household electricity demand revisited," Review of Economic Studies 72, 853-858; and Swan L.G., V. I. Ugursan, 2009, "Modeling of end-use energy consumption in the residential sector: A review of modeling techniques," Renewable and Sustainable Energy Reviews 13, 1819-1835.

Q. HAVE YOU CONDUCTED ANY ANALYSES EXAMINING THE RELATIONSHIP OF ELECTRICITY USAGE AND INCOME?

A. Yes. Figure 1 provides the results of an analysis I have performed using data from the 2020 Residential Electricity Consumption Survey ("RECS") produced by the United States Energy Information Administration ("EIA") and household data from the Census division in which the Pennsylvania is located.[28] The results show a positive relationship between electricity consumption (in kWh terms) and income. This clearly shows that as income increases, electricity consumption increases, and vice versa: as income decreases, electricity usage decreases.

Q. WHAT ARE YOUR CUSTOMER CHARGE RECOMMENDATIONS AND CONCLUSIONS?

A. I recommend that the Commission reject the Company's proposed increase in customer charges for several reasons. First, the Company's proposal is based upon an inaccurate accounting of customer-related costs. A correct analysis of customer-related costs from Citizens' ACOS finds that all residential and commercial rate classes are currently recovering *all* customer-related costs through monthly customer charges. Second, the Company's existing residential and SH customer charges of $13.10 and $20.19 are already higher than the regional average of peer investor-owned utilities, and the proposed increase would make the charges the highest among peers. Third, the proposal would negatively impact the public policy goals of energy efficiency and would burden low-use customers with a greater than average portion of any proposed increase

[28] This census division also includes the states of Connecticut, Maine, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island, and Vermont. This is the most detailed level of aggregation available in the RECS.

in the case. The Commission should keep Citizens' current customer charges for all customers.

VI. CONCLUSIONS AND RECOMMENDATIONS

Q. WHAT ARE YOUR ACOS FINDINGS FOR CITIZENS'?

A. My alternative ACOS analyses shows that Citizens' incorrect classification of secondary-voltage distribution plant skews the allocation of costs and revenue responsibilities away from larger customers and onto residential customers. I recommend the Commission rely on the results of my alternative ACOS as a fair and reasonable estimation of relative costs of service between Citizens' customer classes.

Q. WHAT IS YOUR RECOMMENDATION REGARDING CITIZENS' PROPOSED REVENUE DISTRIBUTION?

A. For Citizens', I recommend that the Commission adopt a more reasonable revenue distribution allocation method based on my alternative ACOS results that also limits the rate increase to the MBL customer class to 1.25 times the overall system average increase. Under Citizens' proposed overall distribution revenue increase of 29.64 percent this reduces the revenue increase to this rate class to 37.05 percent, compared to the Company's proposed distribution rate increase of 75.0 percent.

Q. WHAT IS YOUR RECOMMENDATION REGARDING CITIZENS' PROPOSED RATE DESIGN FOR CUSTOMER CHARGES?

A. I recommend the Commission reject Citizens' proposed increases in customer charges because they disproportionately impact low-income customers and reduce customer incentives to reduce usage, contrary to public goals of promoting energy efficiency. Furthermore, Citizens' existing residential and small commercial customer

charges are already higher than the regional average of peer investor-owned utilities, and the proposed increase would make the charges the highest among peers. Finally, a correct analysis of customer-related costs from Citizens' ACOS finds that all residential and commercial rate classes are currently recovering *all* customer-related costs through monthly customer charges.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

Michael William Deupree
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EDUCATION

M.A. in Economics, Kansas University, 2009

B.A. in Business Economics, Buena Vista University, 2007

PROFESSIONAL EXPERIENCE

Acadian Consulting Group, Baton Rouge, Louisiana

Spring 2025 – Present	Senior Research Consultant
Summer 2021 – Spring 2025	Research Consultant
Summer 2016 – Summer 2021	Research Associate
Winter 2011 – Summer 2016	Senior Research Analyst

Kansas Corporation Commission, Topeka, Kansas

Utilities Division

Summer 2011 – Winter 2011	Senior Research Economist

Research Division

Spring 2009 – Summer 2011	Research Analyst

Kansas Energy Council

Summer 2008 – Spring 2009	Research Assistant

PUBLICATIONS AND REPORTS

1. The challenges of the regulatory review of diversification mergers. With Dr. David E. Dismukes. *The Electricity Journal* 29 (2016) 8-14. (May 2016)

PROFESSIONAL AND CIVIC PRESENTATIONS

1. "Natural Gas Distribution" (2025). Prepared for the Louisiana State University, Center for Energy Studies, Energy Fundamentals 2025. June 24 and July 8, 2025.

2. "Development Trends, Issues, and Challenges with Clean Hydrogen Production" (2025). Prepared for the Michigan State University, Institute of Public Utilities, Annual Regulatory Studies Program. April 15, 2025.

3. "Status and Future of Natural Gas Supply and Infrastructure" (2025). Prepared for the Michigan State University, Institute of Public Utilities, Annual Regulatory Studies Program. April 8, 2025.

4. "Observed Impact of Formula Rate Plans Across the United States" (2024). Prepared for Arizona Corporation Commission Formula Rate Plan Workshop. October 3, 2024.

EXPERT WITNESS, LEGISLATIVE, AND PUBLIC TESTIMONY; EXPERT REPORTS, RECOMMENDATIONS, AND AFFIDAVITS

1. Expert Testimony. Cause No. 46120. (2025). Before the Indiana Utility Regulatory Commission. *Verified Petition of NIPSCO Generation LLC for Certain Determinations by the Commission with Respect to its Jurisdiction Over Petitioner's Activities as a Non-Retail Generator of Electric Power.* On Behalf of the Indiana Office of Utility Consumer Counselor. Issues: Rate Design, Large Data Center Loads.

2. Expert Testimony. Case No. U-21859. (2025). Before the Michigan Public Service Commission. *In the matter of the application of Consumers Energy Company for Ex Parte Approval of Certain Amendments to Rate GPD.* On Behalf of the Michigan Attorney General. Issues: Rate Design, Large Data Center Loads.

3. Expert Testimony. Docket No. R-2025-3053112. (2025). Before the Pennsylvania Public Utilities Commission. *Pennsylvania Public Utility Commission v. Philadelphia Gas Works.* On Behalf of the Pennsylvania Office of Consumer Advocate. Issues: Decoupling, Regulatory Lag.

4. Expert Testimony. Docket No. E-01773A-24-0220. (2025). Before the Arizona Corporation Commission. *In the Matter of the Application of Arizona Electric Power Cooperative, In. for a Hearing to Determine the Fair Value of its Property for Ratemaking Purposes, to Fix a Just and Reasonable Return Thereon and To Approve Rates Designed to Develop Such Return.* On Behalf of Arizona Corporation Commission Staff. Issues: Cost of Service, Qualifying Facilities.

5. Expert Testimony. Case No. U-21816. (2025). Before the Michigan Public Service Commission. *In the matter of Consumer Energy Company's application for the regulatory reviews, revisions, determinations, and/or approvals necessary to fully comply with Public Act 295 of 2008, as amended by Public Act 235 of 2023.* On Behalf of the Attorney General. Issues: Capital Expense, Cost Recovery

6. Expert Testimony. Cause No. 46120. (2024). Before the Indiana Utility Regulatory Commission. *Petition of Northern Indiana Public Service Company LLC Pursuant to Ind. Code §§ 8-1-2-42.4, 8-1-2-61 and 8-1-2.5-6 for (1) Authority to Modify its Retail Rates and Charges for Electric Utility Service Through a Phase in of Rates;*

(2) Approval of New Schedules of Rates and Charges, General Rules and Regulations, and Riders (both Existing and New); (3) Approval of Revised Common and Electric Depreciation Rates Applicable to its Electric Plant in Service; (4) Approval of Necessary and Appropriate Accounting Relief, Including, but Limited to, Authority to Capitalize as Rate Base All Expenditures for Improvements to Petitioner's Information Technology Systems through the Design, Development, and Implementation of a Work and Asset Management ("WAM") Program, to the Extent Necessary; and (5) Approval of Alternative Regulatory Plans for the Partial Waiver of 170 IAC 4-1-16(f) and Proposed Remote Disconnection and Reconnection Process and, to the Extent Necessary, Implementation of a Low Income Program. On Behalf of the Indiana Office of Utility Consumer Counselor. Issues: Cost of Service, Rate Design.

7. Expert Testimony. Cause No. 46097. (2024). Before the Indiana Utility Regulatory Commission. *In the Matter of the Verified Petition of Indiana Michigan Power Company for Approval of Modifications to its Industrial Power Tariff – Tariff I.P.* On Behalf of the Indiana Office of Utility Consumer Counselor. Issues: Rate Design, Large Data Center Loads.

8. Expert Report. Docket No. AHD-00000J-23-0273. (2024). Before the Arizona Corporation Commission. *In the Matter of the Application of the Arizona Corporation Commission's Exploration of Changes to the Up to 10% Annual Reduction in the Export Rate and the 10-Year Export Rate Effective Period Under the Resource Comparison Proxy Methodology Approved in the Value and Cost of Distributed Generation Docket (E-00000J-14-0023).* On Behalf of the Arizona Corporation Commission Staff. Issues: Value of Solar.

9. Expert Testimony. Case No. U-21585. (2024). Before the Michigan Public Service Commission. *In the Matter of the Application of Consumers Energy Company for Authority to Increase its Rates for the Generation and Distribution of Electricity and Other Relief.* On Behalf of the Attorney General. Issues: Capital Expenses.

10. Expert Report. *Review of LPSC Rules Regarding Distributed Generation: Report on Phase II of Rule-Making.* Docket No. R-33929. (2019). *In Re: Review of Policies Related to Customer-owned Solar Generation and Possible Modification of the Commission's Current Net Metering Rules.* On behalf of Louisiana Public Service Commission. Issues: Solar Net Metering.

11. Expert Report. (2011). *2011 Kansas Generation Planning Survey*. On behalf of the Kansas Corporation Commission Staff.

12. Expert Testimony. Docket No. 11-KCPE-581-PRE. (2011). Before the Kansas Corporation Commission. *In the Matter of the Petition of Kansas City Power & Light Company ("KCP&L") for Determination of the Ratemaking Principles and Treatment That Will Apply to the Recovery in Rates of the Costs to be Incurred by KCP&L for Certain Electric Generation Facilities Under K.S.A. 66-1239.* On Behalf

of the Kansas Corporation Commission Staff. Issues: System Planning, Predetermination.

13. Expert Testimony. Docket No. 10-KCPE-795-TAR. (2010). Before the Kansas Corporation Commission. *In the Matter of the Application of Kansas City Power & Light Company for Approval to Implement a Portfolio of Demand Side Management Programs Including Affordability, Energy Efficiency, Demand Response and Educational Programs, and to Implement a Rider for Recovery of Program Costs and Incentives Associated with this Portfolio.* On Behalf of the Kansas Corporation Commission Staff. Issues: Demand Side Management, Cost-Benefit Analyses.

14. Expert Testimony. Docket No. 10-WSEE-775-TAR. (2010). Before the Kansas Corporation Commission. *In the Matter of the Application of Westar Energy, Inc. and Kansas Gas and Electric Company for an Order Authorizing them to participate in Efficiency Kansas, Approve the SimpleSavings Program Rider, and related cost recovery.* On Behalf of the Kansas Corporation Commission Staff. Issues: Demand Side Management, Cost-Benefit Analyses.

15. Expert Testimony. Docket No. 10-BHCG-639-TAR. (2010). Before the Kansas Corporation Commission. *In the Matter of the Application of Black Hills/Kansas Gas Utility Company, LLC, d/b/a Black Hills Energy for Approval to Implement Black Hills Energy's Five-Year Energy Efficiency Plan Consisting of Natural Gas Energy Efficiency Programs to Improve Building and Equipment Efficiency and to Educate About Efficient Energy Usage, to Provide for Program Cost Recovery Through a Rider Mechanism, Permit the Implementation of a Revenue Normalization Mechanism to Replace the Weather Normalization Adjustment, a Performance Incentive Mechanism, and Appropriate Accounting Authority to Defer Expenses and Revenues Associated with the Filing.* On Behalf of the Kansas Corporation Commission Staff. Issues: Demand Side Management, Cost-Benefit Analyses.

16. Expert Testimony. Docket No. 10-EPDE-497-TAR. (2010). Before the Kansas Corporation Commission. *In the Matter of the Application of the Empire District Electric Company for Approval to Implement its Portfolio of Energy Efficiency and Demand Response Programs for its Kansas Customers, to Provide for Program Cost Recovery and Lost Revenue Through a Rider Mechanism, to Obtain any Necessary Waivers for the Commission, and for Appropriate Accounting Authority to Defer Expenses and Revenues Associated with the Filing.* On Behalf of the Kansas Corporation Commission Staff. Issues: Demand Side Management, Cost-Benefit Analyses.

17. Expert Testimony. Docket No. 10-KGSG-421-TAR. (2010). Before the Kansas Corporation Commission. *In the Matter of the Application of Kansas Gas Service, a Division of ONEOK, Inc., for Approval to Implement the Efficiency Kansas Energy Efficiency Program, to Implement Natural Gas Energy Efficiency Programs to Improve Building and Equipment Efficiency and to Educate about Efficient Energy*

Usage, To Provide for Program Cost Recovery Through a Rider Mechanism, to Establish Administrative Charges and a Program Initiation Fee, Permit the Implementation of a Revenue Decoupling Mechanism, and Appropriate Accounting Authority to Defer Expenses and Revenues Associated with the Filing. On Behalf of the Kansas Corporation Commission Staff. Issues: Demand Side Management, Cost-Benefit Analyses.

Table of Exhibits

Title	Exhibit
Summary of Results of Company's Proposed ACOS	Exhibit MWD-1
Summary of Results of Alternative ACOS	Exhibit MWD-2
Summary of Company's Proposed Revenue Allocation	Exhibit MWD-3
Summary of Results of Alternative Revenue Allocation	Exhibit MWD-4

Summary of Results of Company's Proposed ACOS: Relative Rate of Return at Current Rates

Line No.	Account Description	Total Citizens	Residential Service (RS)	Commercial and Industrial Service: Space Heating (SH)	Commercial and Industrial Service: General L&P (GLP-1)	Commercial and Industrial Service: General L&P (GLP-3)	Lighting Service: Municipal (MBL)	Lighting Service: Outdoor (OL)
1	**Rate Base**							
2	Total Utility Plant	$ 35,369,114	$ 23,173,687	$ 51,352	$ 5,479,820	$ 5,636,190	$ 395,062	$ 633,003
3	Total Depreciation Reserve	(18,189,781)	(11,828,333)	(30,384)	(2,811,059)	(3,218,027)	(112,489)	(189,489)
4	Total Other Rate Base Items	(86,988)	105,917	113	(103,854)	(89,973)	177	633
5	**Total Rate Base**	**$ 17,092,345**	**$ 11,451,271**	**$ 21,081**	**$ 2,564,908**	**$ 2,328,190**	**$ 282,749**	**$ 444,146**
6	**Operating Income**							
7	**Operating Revenue**							
8	Distribution Revenues	$ 6,055,143	$ 3,903,746	$ 8,741	$ 1,092,138	$ 909,143	$ 26,151	$ 115,224
9	Forfeited Discounts	29,586	19,074	43	5,336	4,442	128	563
10	Other Operating Revenues	74,278	48,754	105	11,479	13,439	104	397
11	**Total Operating Revenues**	**$ 6,159,007**	**$ 3,971,574**	**$ 8,889**	**$ 1,108,954**	**$ 927,024**	**$ 26,383**	**$ 116,184**
12	**Operating Expenses**							
13	Distribution and Transmission Expenses	$ 1,929,647	$ 1,260,983	$ 2,695	$ 290,273	$ 336,697	$ 14,541	$ 24,458
14	Customer Account and Service Expenses	549,379	448,177	257	88,671	8,912	1,014	2,349
15	Administration and General Expenses	1,623,036	1,112,852	1,930	247,211	217,392	16,591	27,059
16	Depreciation Expense	1,409,998	918,048	2,007	216,554	219,018	21,005	33,364
17	Taxes Other than Income Tax	442,957	287,405	626	77,407	65,838	2,839	8,842
18	Income Taxes	(46,387)	(30,393)	(67)	(7,187)	(7,392)	(518)	(830)
19	**Total Operating Expenses**	**$ 5,908,629**	**$ 3,997,072**	**$ 7,448**	**$ 912,930**	**$ 840,465**	**$ 55,471**	**$ 95,242**
20	**Net Operating Income**	**$ 250,378**	**$ (25,498)**	**$ 1,441**	**$ 196,023**	**$ 86,559**	**$ (29,088)**	**$ 20,942**
21	**Rate of Return on Rate Base ("ROR")**	**1.46%**	**-0.22%**	**6.84%**	**7.64%**	**3.72%**	**-10.29%**	**4.72%**
22	**Relative Rate of Return ("RROR")**	**1.00**	**(0.15)**	**4.67**	**5.22**	**2.54**	**(7.02)**	**3.22**

Source: Company's Response to OCA-I-1, Attachment A (Schedule E).

Summary of Results of Company's Proposed ACOS: Required Increase at Equalized Rates

Line No.	Account Description	Total Citizens	Residential Service (RS)	Commercial and Industrial Service: Space Heating (SH)	Commercial and Industrial Service: General L&P (GLP-1)	Commercial and Industrial Service: General L&P (GLP-3)	Lighting Service: Municipal (MBL)	Lighting Service: Outdoor (OL)
1	**Revenue Requirement**							
2	**Required Income Under Company's Proposed ROR**							
3	Total Rate Base	$ 17,092,345	$ 11,451,271	$ 21,081	$ 2,564,908	$ 2,328,190	$ 282,749	$ 444,146
4	Proposed Rate of Return	8.49%	8.49%	8.49%	8.49%	8.49%	8.49%	8.49%
5	**Required Operating Income @ 8.49% ROR**	**$ 1,451,140**	**$ 972,213**	**$ 1,790**	**$ 217,761**	**$ 197,663**	**$ 24,005**	**$ 37,708**
6	**Operating Expenses**							
7	Current Operating Expenses (Less Adjustments)	$ 4,008,123	$ 2,759,857	$ 4,759	$ 611,123	$ 549,775	$ 30,969	$ 51,640
8	Uncollectibles Expense	30,900	19,921	45	5,573	4,639	133	588
9	Depreciation Expense	1,409,998	918,048	2,007	216,554	219,018	21,005	33,364
10	Regulatory Commission Expense	63,038	42,233	78	9,460	8,587	1,043	1,638
11	Taxes Other than Income	85,704	57,084	111	12,971	12,198	1,296	2,044
12	Income Taxes	441,499	295,789	545	66,252	60,138	7,303	11,472
13	GRT	463,130	313,269	576	70,456	64,858	5,349	8,622
14	**Total Operating Expenses**	**$ 6,502,392**	**$ 4,406,202**	**$ 8,120**	**$ 992,389**	**$ 919,214**	**$ 67,099**	**$ 109,368**
15	**Total Revenue Requirement**	**$ 7,953,532**	**$ 5,378,415**	**$ 9,910**	**$ 1,210,150**	**$ 1,116,877**	**$ 91,104**	**$ 147,076**
16	**Revenue Deficiency**							
17	**Operating Revenues**							
18	Distribution Revenues	$ 6,055,143	$ 3,903,746	$ 8,741	$ 1,092,138	$ 909,143	$ 26,151	$ 115,224
19	Forfeited Discounts	29,586	19,074	43	5,336	4,442	128	563
20	Other Operating Revenues	74,278	48,754	105	11,479	13,439	104	397
21	**Total Operating Revenues**	**$ 6,159,007**	**$ 3,971,574**	**$ 8,889**	**$ 1,108,954**	**$ 927,024**	**$ 26,383**	**$ 116,184**
22	**Revenue Deficiency (Surplus)**	**$ 1,794,524**	**$ 1,406,841**	**$ 1,021**	**$ 101,196**	**$ 189,853**	**$ 64,721**	**$ 30,892**
23	**Required Rate Increase (Decrease)**	**29.64%**	**36.04%**	**11.68%**	**9.27%**	**20.88%**	**247.49%**	**26.81%**
24	**Relative Rate Increase**	**1.00**	**1.22**	**0.39**	**0.31**	**0.70**	**8.35**	**0.90**

Source: Company's Response to OCA-I-1, Attachment A (Schedule E).

Summary of Results of Alternative ACOS: Relative Rate of Return at Current Rates

Line No.	Account Description	Total Citizens	Residential Service (RS)	Commercial and Industrial Service: Space Heating (SH)	Commercial and Industrial Service: General L&P (GLP-1)	Commercial and Industrial Service: General L&P (GLP-3)	Lighting Service: Municipal (MBL)	Lighting Service: Outdoor (OL)
1	**Rate Base**							
2	Total Utility Plant	$ 35,369,113	$ 22,565,891	$ 57,899	$ 5,521,554	$ 6,208,276	$ 389,410	$ 626,084
3	Total Depreciation Reserve	(18,189,780)	(11,513,819)	(33,772)	(2,832,654)	(3,514,062)	(109,565)	(185,909)
4	Total Other Rate Base Items	(86,988)	103,675	136	(103,727)	(87,961)	205	685
5	**Total Rate Base**	**$ 17,092,345**	**$ 11,155,747**	**$ 24,263**	**$ 2,585,172**	**$ 2,606,253**	**$ 280,051**	**$ 440,860**
6	**Operating Income**							
7	**Operating Revenue**							
8	Distribution Revenues	$ 6,055,143	$ 3,903,746	$ 8,741	$ 1,092,138	$ 909,143	$ 26,151	$ 115,224
9	Forfeited Discounts	29,586	19,074	43	5,336	4,442	128	563
10	Other Operating Revenues	74,278	48,754	105	11,479	13,439	104	397
11	**Total Operating Revenues**	**$ 6,159,007**	**$ 3,971,574**	**$ 8,889**	**$ 1,108,954**	**$ 927,024**	**$ 26,383**	**$ 116,184**
12	**Operating Expenses**							
13	Distribution and Transmission Expenses	$ 1,929,647	$ 1,226,673	$ 3,064	$ 292,629	$ 368,991	$ 14,222	$ 24,068
14	Customer Account and Service Expenses	549,379	448,177	257	88,671	8,912	1,014	2,349
15	Administration and General Expenses	1,623,036	1,089,747	2,173	248,655	238,636	16,630	27,195
16	Depreciation Expense	1,409,997	893,770	2,269	218,221	241,870	20,779	33,088
17	Taxes Other than Income Tax	442,957	285,926	642	77,509	67,230	2,825	8,825
18	Income Taxes	(46,387)	(29,595)	(76)	(7,242)	(8,142)	(511)	(821)
19	**Total Operating Expenses**	**$ 5,908,629**	**$ 3,914,697**	**$ 8,329**	**$ 918,444**	**$ 917,496**	**$ 54,960**	**$ 94,703**
20	**Net Operating Income**	**$ 250,378**	**$ 56,877**	**$ 560**	**$ 190,510**	**$ 9,528**	**$ (28,577)**	**$ 21,481**
21	**Rate of Return on Rate Base ("ROR")**	**1.46%**	**0.51%**	**2.31%**	**7.37%**	**0.37%**	**-10.20%**	**4.87%**
22	**Relative Rate of Return ("RROR")**	**1.00**	**0.35**	**1.57**	**5.03**	**0.25**	**(6.97)**	**3.33**

Source: Company's Response to OCA-I-1, Attachment A (Schedule E).

Summary of Results of Alternative ACOS: Required Increase at Equalized Rates

Line No.	Account Description	Total Citizens	Residential Service (RS)	Commercial and Industrial Service: Space Heating (SH)	Commercial and Industrial Service: General L&P (GLP-1)	Commercial and Industrial Service: General L&P (GLP-3)	Lighting Service: Municipal (MBL)	Lighting Service: Outdoor (OL)
1	**Revenue Requirement**							
2	**Required Income Under Company's Proposed ROR**							
3	Total Rate Base	$17,092,345	$11,155,747	$ 24,263	$ 2,585,172	$ 2,606,253	$ 280,051	$ 440,860
4	Proposed Rate of Return	8.49%	8.49%	8.49%	8.49%	8.49%	8.49%	8.49%
5	**Required Operating Income @ 8.49% ROR**	**$ 1,451,140**	**$ 947,123**	**$ 2,060**	**$ 219,481**	**$ 221,271**	**$ 23,776**	**$ 37,429**
6	**Operating Expenses**							
7	Current Operating Expenses (Less Adjustments)	$ 4,008,123	$ 2,703,532	$ 5,360	$ 614,848	$ 602,287	$ 30,700	$ 51,397
8	Uncollectibles Expense	30,900	19,921	45	5,573	4,639	133	588
9	Depreciation Expense	1,409,997	893,770	2,269	218,221	241,870	20,779	33,088
10	Regulatory Commission Expense	63,038	41,143	89	9,534	9,612	1,033	1,626
11	Taxes Other than Income	85,704	55,604	127	13,073	13,591	1,282	2,027
12	Income Taxes	441,499	288,155	627	66,776	67,320	7,234	11,387
13	GRT	463,130	306,032	654	70,944	71,639	5,298	8,565
14	**Total Operating Expenses**	**$ 6,502,391**	**$ 4,308,158**	**$ 9,170**	**$ 998,969**	**$ 1,010,958**	**$ 66,459**	**$ 108,678**
15	**Total Revenue Requirement**	**$ 7,953,532**	**$ 5,255,281**	**$ 11,230**	**$ 1,218,450**	**$ 1,232,228**	**$ 90,236**	**$ 146,107**
16	**Revenue Deficiency**							
17	**Operating Revenues**							
18	Distribution Revenues	$ 6,055,143	$ 3,903,746	$ 8,741	$ 1,092,138	$ 909,143	$ 26,151	$ 115,224
19	Forfeited Discounts	29,586	19,074	43	5,336	4,442	128	563
20	Other Operating Revenues	74,278	48,754	105	11,479	13,439	104	397
21	**Total Operating Revenues**	**$ 6,159,007**	**$ 3,971,574**	**$ 8,889**	**$ 1,108,954**	**$ 927,024**	**$ 26,383**	**$ 116,184**
22	**Revenue Deficiency (Surplus)**	**$ 1,794,524**	**$ 1,283,707**	**$ 2,341**	**$ 109,496**	**$ 305,204**	**$ 63,853**	**$ 29,923**
23	**Required Rate Increase (Decrease)**	**29.64%**	**32.88%**	**26.78%**	**10.03%**	**33.57%**	**244.17%**	**25.97%**
24	**Relative Rate Increase**	**1.00**	**1.11**	**0.90**	**0.34**	**1.13**	**8.24**	**0.88**

Source: Company's Response to OCA-I-1, Attachment A (Schedule E).

Summary of Company's Proposed Revenue Allocation

Witness: Deupree
Docket No. R-2025-3054394
Exhibit MWD-3 (Citizens)

Line No.	Account Description	Total Citizens	Residential Service (RS)	Commercial and Industrial Service			Lighting Service	
				Space Heating (SH)	General L&P (GLP-1)	General L&P (GLP-3)	Municipal (MBL)	Outdoor (OL)
1	**Allocated Cost of Service Results**							
2	Distribution Revenues	$ 6,055,143	$ 3,903,746	$ 8,741	$ 1,092,138	$ 909,143	$ 26,151	$115,224
3	Forfeited Discounts/Other Revenues	103,864	67,828	148	16,815	17,881	232	960
4	Current Operating Revenues	$ 6,159,007	$ 3,971,574	$ 8,889	$ 1,108,954	$ 927,024	$ 26,383	$116,184
5	Operating Income	$ 250,378	$ (25,498)	$ 1,441	$ 196,023	$ 86,559	$ (29,088)	$ 20,942
6	Electric Rate Base	$17,092,345	$11,451,271	$ 21,081	$ 2,564,908	$ 2,328,190	$ 282,749	$444,146
7	**Rate of Return**	1.46%	-0.22%	6.84%	7.64%	3.72%	-10.29%	4.72%
8	**Relative Rate of Return**	1.00	(0.15)	4.67	5.22	2.54	(7.02)	3.22
9	**Proposed Revenue Increase**							
10	Proposed Rate of Return	8.49%						
11	Current Operating Revenues	$ 6,159,007						
12	Proposed Operating Revenue Increase	1,794,524						
13	**Proposed Revenue Requirement**	$ 7,953,532						
14	**Proposed Revenue Allocation at Full Cost of Service**							
15	Distribution Revenues	$ 6,055,143	$ 3,903,746	$ 8,741	$ 1,092,138	$ 909,143	$ 26,151	$115,224
16	Forfeited Discounts/Other Revenues	103,864	67,828	148	16,815	17,881	232	960
17	Current Operating Revenues	$ 6,159,007	$ 3,971,574	$ 8,889	$ 1,108,954	$ 927,024	$ 26,383	$116,184
18	Total Revenue Requirement at Equal Rates of Return	7,953,532	5,378,415	9,910	1,210,150	1,116,877	91,104	147,076
19	Incremental Revenue Increase at Equal Rates of Return	$ 1,794,524	$ 1,406,841	$ 1,021	$ 101,196	$ 189,853	$ 64,721	$ 30,892
20	**Precent Increase at Proposed Rate of Return**	**29.64%**	**36.04%**	**11.68%**	**9.27%**	**20.88%**	**247.49%**	**26.81%**
21	**Relative Increase**	**1.00**	**1.22**	**0.39**	**0.31**	**0.70**	**8.35**	**0.90**
22	**Proposed Mitigated Revenue Allocation**							
23	Current Distribution Revenues	$ 6,055,143	$ 3,903,746	$ 8,741	$ 1,092,138	$ 909,143	$ 26,151	$115,224
24	Proposed Distribution Revenue Increase	1,794,524	1,244,862	2,078	250,793	243,980	19,613	33,199
25	**Proposed Distribution Revenues**	**$ 7,849,668**	**$ 5,148,608**	**$ 10,819**	**$ 1,342,931**	**$ 1,153,123**	**$ 45,764**	**$148,423**
26	**Proposed Revenue Change (%)**	**29.64%**	**31.89%**	**23.77%**	**22.96%**	**26.84%**	**75.00%**	**28.81%**
27	**Relative Proposed Revenue Increase**	**1.00**	**1.08**	**0.80**	**0.77**	**0.91**	**2.53**	**0.97**

Source: Company's Response to I&E-RE-1-D, Attachment A.

Summary of Alternative Proposed Revenue Allocation

Witness: Deupree
Docket No. R-2025-3054394
Exhibit MWD-4 (Citizens)

Line No.	Account Description	Total Citizens	Residential Service (RS)	Commercial and Industrial Service: Space Heating (SH)	Commercial and Industrial Service: General L&P (GLP-1)	Commercial and Industrial Service: General L&P (GLP-3)	Lighting Service: Municipal (MBL)	Lighting Service: Outdoor (OL)
1	**Allocated Cost of Service Results**							
2	Distribution Revenues	$ 6,055,143	$ 3,903,746	$ 8,741	$ 1,092,138	$ 909,143	$ 26,151	$ 115,224
3	Forfeited Discounts/Other Revenues	103,864	67,828	148	16,815	17,881	232	960
4	Current Operating Revenues	$ 6,159,007	$ 3,971,574	$ 8,889	$ 1,108,954	$ 927,024	$ 26,383	$ 116,184
5	Operating Income	$ 250,378	$ 56,877	$ 560	$ 190,510	$ 9,528	$ (28,577)	$ 21,481
6	Electric Rate Base	$ 17,092,345	$ 11,155,747	$ 24,263	$ 2,585,172	$ 2,606,253	$ 280,051	$ 440,860
7	**Rate of Return**	1.46%	0.51%	2.31%	7.37%	0.37%	-10.20%	4.87%
8	**Relative Rate of Return**	1.00	0.35	1.57	5.03	0.25	(6.97)	3.33
9	**Proposed Revenue Increase**							
10	Proposed Rate of Return	8.49%						
11	Current Operating Revenues	$ 6,159,007						
12	Proposed Operating Revenue Increase	1,794,525						
13	**Proposed Revenue Requirement**	$ 7,953,532						
14	**Proposed Revenue Allocation at Full Cost of Service**							
15	Distribution Revenues	$ 6,055,143	$ 3,903,746	$ 8,741	$ 1,092,138	$ 909,143	$ 26,151	$ 115,224
16	Forfeited Discounts/Other Revenues	103,864	67,828	148	16,815	17,881	232	960
17	Current Operating Revenues	$ 6,159,007	$ 3,971,574	$ 8,889	$ 1,108,954	$ 927,024	$ 26,383	$ 116,184
18	Total Revenue Requirement at Equal Rates of Return	7,953,532	5,255,281	11,230	1,218,450	1,232,228	90,236	146,107
19	Incremental Revenue Increase at Equal Rates of Return	$ 1,794,525	$ 1,283,707	$ 2,341	$ 109,496	$ 305,204	$ 63,853	$ 29,923
20	**Precent Increase at Proposed Rate of Return**	**29.64%**	**32.88%**	**26.78%**	**10.03%**	**33.57%**	**244.17%**	**25.97%**
21	**Relative Increase**	**1.00**	**1.11**	**0.90**	**0.34**	**1.13**	**8.24**	**0.88**
22	**Proposed Mitigated Revenue Allocation**							
23	Step One: Company Modeled Distribution Revenue Increase							
24	Current Distribution Revenues	$ 6,055,143	$ 3,903,746	$ 8,741	$ 1,092,138	$ 909,143	$ 26,151	$ 115,224
25	Proposed Distribution Revenue Increase	1,794,525	1,203,615	2,517	253,518	282,390	19,613	32,871
26	Proposed Distribution Revenue Increase after Step One	$ 7,849,668	$ 5,107,361	$ 11,258	$ 1,345,657	$ 1,191,533	$ 45,764	$ 148,095
27	Step two: MBL Cap of 1.25 Times System Average							
28	Cap of 1.25 Times System Average	37.05%						
29	MBL Cap of 1.25 Times System Average	$ 9,688					$ 9,688	
30	Step Two Amount to be Reallocated	$ 9,925					$ 9,925	
31	Basis for Reallocation	$ 6,028,993	$ 3,903,746	$ 8,741	$ 1,092,138	$ 909,143	$ -	$ 115,224
32	Step Two Reallocation	$ 9,925	$ 6,427	$ 14	$ 1,798	$ 1,497	$ -	$ 190
33	Proposed Distribution Revenue Increase after Step Two	$ 1,794,525	$ 1,210,041	$ 2,532	$ 255,316	$ 283,887	$ 9,688	$ 33,060
34	**Total Proposed Distribution Revenues**	**$ 7,849,668**	**$ 5,113,788**	**$ 11,273**	**$ 1,347,455**	**$ 1,193,030**	**$ 35,838**	**$ 148,284**
35	**Proposed Revenue Change (%)**	**29.64%**	**31.00%**	**28.96%**	**23.38%**	**31.23%**	**37.05%**	**28.69%**
36	**Relative Proposed Revenue Increase**	**1.00**	**1.05**	**0.98**	**0.79**	**1.05**	**1.25**	**0.97**

Source: Company's Response to I&E-RE-1-D, Attachment A.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No. R-2025-3054394
	:	
Citizens' Electric Co. of Lewisburg, PA	:	

VERIFICATION

I, Michael W. Deupree, hereby state that the facts above set forth in my Direct Testimony, OCA Statement No. 3, are true and correct to the best of my knowledge, information, and belief and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa.C.S. § 4904 (relating to unsworn falsification to authorities).

DATED: July 15, 2025

Signature:
Michael W. Deupree

Address: Acadian Consulting Group
5800 One Perkins Place Drive
Suite 5-F
Baton Rouge, LA 70808

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	Docket No.: R-2025-3054393
v.	:	
	:	
Valley Energy, Inc.	:	

DIRECT TESTIMONY

OF

Michael Deupree

On behalf of the

PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

OCA Statement 3

Date Served: July 15, 2025

Table of Contents

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I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS?

A. My name is Michael W. Deupree. My business address is 5800 One Perkins Place Drive, Suite 5-F, Baton Rouge, Louisiana, 70808.

Q. PLEASE STATE YOUR OCCUPATION AND CURRENT PLACE OF EMPLOYMENT?

A. I am a Senior Research Consultant with the Acadian Consulting Group ("ACG"), a research and consulting firm that specializes in the analysis of regulatory, economic, financial, accounting, statistical, and public policy issues associated with regulated and energy industries. ACG is a Louisiana-registered partnership, formed in 1995, and is located in Baton Rouge, Louisiana.

Q. PLEASE DESCRIBE YOUR PROFESSIONAL QUALIFICATIONS.

A. I hold a Bachelor of Arts degree in Business Economics from Buena Vista University in Storm Lake, Iowa, and a Master of Arts degree in Economics from the University of Kansas in Lawrence, Kansas. I began my professional career with the Staff of the Kansas Corporation Commission in 2008 while in graduate school conducting analyses of topics related to energy and economy as a Research Assistant, eventually being promoted to a Research Analyst and later Senior Research Economist after graduation. I left the Kansas Corporation Commission to take a position with ACG in late 2011, where I have been promoted to positions of increasing responsibility since, including my current position which I started in mid-2021. At ACG I managed research teams supporting expert testimony and have overseen dozens of litigated preceding, including multiple proceedings on behalf of the AG. Appendix A provides my professional

resume, which includes a listing of my publications, presentations, pre-filed expert witness testimony, expert reports, and expert legislative testimony.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I have been retained by the Pennsylvania Office of the Consumer Advocate ("OCA") to address matters related to the general rate case filed by Valley Energy, Inc. ("Valley" or "the Company"). I specifically have been asked to review the Company's filing pertaining to issues involving an Allocated Class Cost of Service Study ("ACOS"), Cost of Service Study ("COSS") and rate design.

II. COST OF SERVICE AND REVENUE DISTRIBUTION

Q. HAS THE COMPANY PREPARED AN ACOS OR COSS IN THE CURRENT PROCEEDING?

A. No. The Company has not prepared an ACOS or COSS in the current proceeding. Instead, the Company proposes to increase all rate classes, other than contract transportation customers, equally by 29.56 percent.[1]

Q. HAVE YOU REVIEWED ANY PRIOR ACOS OR COSS FOR THE COMPANY?

A. No. According to the Company, it is unaware of any prior ACOS or COSS that has been conducted for Valley.[2]

[1] Direct Testimony of Howard S. Gorman at 18:14-15.

[2] Company's Response to OCA-IX-1.

Q. WHAT ARE YOUR RECOMMENDATIONS REGARDING THE PROPOSED REVENUE DISTRIBUTION FOR THE COMPANY?

A. In light of the Company having no cost basis, either in the current proceeding or prior proceedings, for which to allocate the proposed revenue increase between rate classes, I have reviewed the Company's proposed equal allocation of its proposed revenue increase in the current proceeding and find the proposal to be reasonable.

III. RATE DESIGN

Table 1: Summary of Company's Proposed Customer Charges

Rate Schedule	Current Charge	Proposed Charge	Percent Increase
Rate R - Residential	$12.35	$14.00	13.4%
Rate C - Commercial	$21.95	$25.00	13.9%
Rate IS - Interruptible Service	$82.00	$100.00	22.0%
Rate SI - Small Industrial	$82.00	$100.00	22.0%
Rate ST - Transport Firm	$82.00	$100.00	22.0%
Transport Firm - DDQ	$21.95	$25.00	13.9%
Rate I - Large Industrial Firm	$0.00	$300.00	-
Transport - Interruptible	$82.00	$100.00	22.0%

Source: Company's Response to I&E-RE-1-D, Attachment A

Q. PLEASE DISCUSS THE COMPANY'S CUSTOMER CHARGE PROPOSAL.

A. As summarized by Table 1, the Company is proposing to increase the residential ("Rate R") customer charge from $12.35 to $14.00 per month, representing a 13.4 percent increase.[3] Likewise, the Company proposes increasing the commercial ("Rate C") customer charge from $21.95 to $25.00 per month, representing a nearly 13.9 percent increase.[4]

[3] Direct Testimony of Howard Gorman, Exhibit HSG-1, Schedule B5.

[4] *Id.*

Q. DOES THE COMPANY HAVE A COST OF SERVICE BASIS FOR ITS PROPOSED CUSTOMER CHARGES?

A. No. The Company has not performed a COSS in the current proceeding,[5] nor is it aware of any prior COSS that has been performed for its system in the past.[6] Instead, its proposed customer charges are based on comparisons to those charged by other Pennsylvania utilities.[7]

Table 2: Survey of Regional Customer Charges

Company	State	Residential Customer Charge ($/month)	Commercial Customer Charge ($/month)
Valley Energy, Inc (Current)	**PA**	**$ 12.35**	**$ 21.95**
Valley Energy, Inc (Proposed)	**PA**	**$ 14.00**	**$ 25.00**
Atmos Energy Corporation	VA	13.24	20.52
Chesapeake Utilities	MD	8.00	22.50
Columbia Gas of Maryland, Inc.	MD	16.50	68.00
Consumers Gas Utility Company	WV	16.80	9.90
Corning Natural Gas Corporation	NY	22.00	33.29
Peoples Gas	WV	8.50	12.50
Southern Public Service Company	WV	13.95	7.05
Southwestern Virginia Gas Company	VA	12.00	17.00
Union Oil & Gas, Inc.	WV	13.13	13.13
Peer Group Average		**$ 13.79**	**$ 22.65**

Source: Utility Tariffs

Q. HAVE YOU COMPARED THE COMPANY'S PROPOSED RESIDENTIAL AND COMMERCIAL CUSTOMER CHARGES TO OTHER REGIONAL NATURAL GAS UTILITIES?

A. Yes, and this analysis is presented in Table 2, which surveys current residential and small commercial customer charges among other regional gas utility companies. The

[5] Direct Testimony of Howard S. Gorman at 18:14-15.

[6] Company's Response to OCA-IX-1.

[7] Direct Testimony of Howard S. Gorman at 18:15-16.

Company's current residential customer charge of $12.35 per month is slightly below the average regional residential customer charge of $13.79 for other regional utilities. This survey also shows that there are only three (out of nine) gas utility companies in the survey that have residential customer charges greater than the Company's proposed charge of $14.00 per month. Likewise, the Company's current commercial customer charge of $21.95 per month is slightly below the average regional commercial customer charge of $22.65 per month. This survey also shows that there are only two (out of nine) gas utility companies in the survey that have commercial customer charges greater than the Company's proposed charge of $25.00 per month.

Q. IS THE COMPANY'S PROPOSAL TO INCREASE THE CUSTOMER CHARGE CONSISTENT WITH PROMOTING ENERGY EFFICIENCY AND CONSERVATION?

A. No. The Company's rate design proposal is inconsistent with energy efficiency, since it reduces economic incentives for ratepayers to control their monthly utility bills through energy efficiency and conservation efforts, because only the variable component of bills is avoidable.

Q. HAVE OTHER REGULATORS RECOGNIZED THE NEGATIVE IMPACTS THAT CUSTOMER CHARGE INCREASES CAN HAVE FOR ENERGY EFFICIENCY?

A. Yes. In rejecting a request by Baltimore Gas and Electric ("BGE") to increase customer charges as part of a larger rate design proposal, the Maryland Public Service Commission ("MPSC") recognized the need to allow customers the opportunity to control their monthly bills by reducing energy usage.

> Even though this issue was virtually uncontested by the parties, we find we must reject Staff's proposal to increase the fixed customer charge from $7.50 to $8.36. Based on the reasoning that ratepayers should be offered the opportunity to

> control their monthly bills to some degree by controlling their energy usage, we instead adopt the Company's proposal to achieve the entire revenue requirement increase through volumetric and demand charges. This approach also is consistent with and supports our EmPOWER Maryland goals.[8]

Q. CAN YOU POINT TO ANY OTHER REGULATORY EXAMPLES?

A. Yes. The Montana Public Service Commission ("MT PSC") addressed this issue in evaluating, and rejecting, a proposal by Energy West Montana to eliminate volumetric charges and only have one fixed monthly customer charge (known as a "straight-fixed variable" or "SFV" rate design):

> The Commission agrees that most distribution costs are not avoidable, and that volumetric distribution charges may encourage conservation actions that, all other things being equal, reduce the utility's embedded cost recovery between rate cases and contribute to future rate increases.
>
> …
>
> The Commission agrees that an SFV rate design is a clean and administratively inexpensive way to decouple revenue from volume. An often-cited public policy justification for revenue decoupling is to remove the volume disincentive for cost-effective conservation investment by a gas distribution company, which through SFV and other decoupling methods is rendered indifferent to the volume of gas consumed. Yet, SFV rates decouple revenue at the cost of decreasing returns to conservation investment by customers. For this reason the net conservation benefit of revenue decoupling via SFV rates is not clear, and may be negative.[9]

---

[8] Maryland Public Service Commission Case No. 9299, In the Matter of the Application of Baltimore Gas and Electric Company for Adjustment in its Electric and Gas Base Rates (*"Case No. 9299"*). Order No. 85374 at p. 99, rel. February 22, 2013.

[9] In The Matter Of Energy West Montana, Application To Establish Increased Service Rates In Its Great Falls, Cascade, And West Yellowstone Service Areas, Montana Public Service Commission, Docket No. D2010.9.90, Order No, 7132c, at 29–30, rel. November 17, 2011.

Q. HAVE ANY REGULATORY RESEARCH INSTITUTES ADDRESSED THE ISSUE OF THE RELATIONSHIP BETWEEN HIGH CUSTOMER CHARGES AND ENERGY EFFICIENCY?

A. Yes. A research document presented for consideration by the membership of the National Association of Regulatory Utility Commissioners ("NARUC") also notes that extreme increases in customer charges, that typically happen under SFV rate design proposals, are problematic because of their effects on customer incentives to conserve energy:

> **Straight-Fixed Variable Rate Design.** This mechanism eliminates all variable distribution charges and costs are recovered through a fixed delivery services charge or an increase in the fixed customer charge alone. With this approach, it is assumed that a utility's revenues would be unaffected by changes in sales levels if all its overhead or fixed costs are recovered in the fixed portion of customers' bills. This approach has been criticized for having the unintended effect of reducing customers' incentive to use less electricity or gas by eliminating their volumetric charges and billing a fixed monthly rate, regardless of how much customers consume.[10]

Q. HAS ANY NATIONAL PUBLIC POLICY ANALYSIS NOTED THE EFFICIENCY DISINCENTIVES ASSOCIATED WITH HIGH CUSTOMER CHARGES?

A. Yes. The National Action Plan for Energy Efficiency ("NAPEE"), a joint venture of the U.S. Department of Energy and U.S. Environmental Protection Agency, published a whitepaper on various rate design effects on encouraging energy efficient behaviors. The NAPEE postulated that rate designs over-emphasizing customer charges, like SFV, can

[10] "Decoupling for Electric & Gas Utilities: Frequently Asked Questions (FAQ)" Grants & Research Department, National Association of Regulatory Utility Commissioners, at 5 (Sept. 2007) (emphasis added).

deter or weaken the economic signals sent to customers to change their energy usage behavior and make investments in energy efficiency devices:

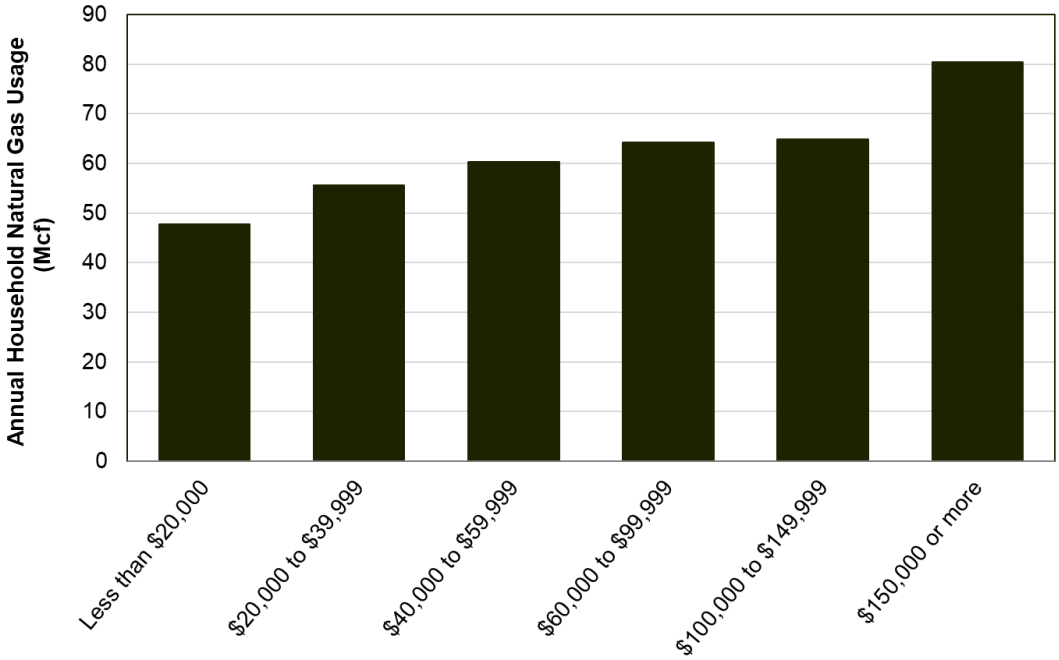
> Because [SFV] tends to shift costs out of volumetric charges, it tends to reduce customers' efficiency incentive, because the marginal price of additional consumption is reduced. While SFV rates are being considered to better reflect the utility's costs behind the rate, these rates do not encourage customers to change energy usage behavior or invest in efficiency technologies. Such customer disincentives persist even when SFV rates are applied to individual components of the bill, such as charges for distribution service.[11]

Q. CAN HIGH CUSTOMER CHARGES LEAD TO OTHER PROBLEMS?

A. Yes. In addition to disincentivizing energy efficiency, increased customer charges also shift the rate burden within a customer class to lower-use customers. This results in equity concerns as lower-use customers have been shown to be consistently associated with lower-income households in empirical research.

[11] Customer Incentives for Energy Efficiency Through Electric and Natural Gas Rate Design, National Action Plan for Energy Efficiency at 13-14, prepared by William Prindle, ICF International, Inc. (Sept. 2009) (emphasis added).

Figure 1: Analysis of Natural Gas Usage and Household Income



Source: EIA 2020 Residential Energy Consumption Survey

Q. HAVE YOU CONDUCTED ANY ANALYSES EXAMINING THE RELATIONSHIP OF NATURAL GAS USAGE AND INCOME?

A. Yes. Figure 1 provides the results of an analysis I have performed using data from the 2020 Residential Electricity Consumption Survey ("RECS") produced by the United States Energy Information Administration ("EIA") and household data from the Census division in which the state of Pennsylvania is located.[12] The results show a positive relationship between natural gas consumption (in Mcf terms) and income. This clearly shows that as income increases, electricity consumption increases, and vice versa: as income decreases, electricity usage decreases.

[12] This census division also includes the states of Connecticut, Maine, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island, and Vermont. This is the most detailed level of aggregation available in the RECS.

Q. WHAT ARE YOUR CUSTOMER CHARGE RECOMMENDATIONS AND CONCLUSIONS?

A. I recommend that the Commission reject the Company's proposed increase in customer charges since the Company has no cost basis for its proposed customer charges. The Company's current residential and commercial customer charges are similarly near the average of other similarly situated natural gas distribution utilities in the region. Finally, the proposal would negatively impact the public policy goals of energy efficiency and would burden low-use customers with a greater than average portion of any proposed increase in the case.

Q. DO YOU HAVE AN ALTERNATIVE RECOMMENDATION IF THE COMMISSION DETERMINES AN INCREASE IN THE COMPANY'S CUSTOMER CHARGE IS WARRANTED?

A. Yes. If the Commission determines that increases in the Company's customer charges are warranted, I recommend that the Commission cap these increases to no more than the overall system average increase. This will prevent Company rates from becoming more reliant on fixed monthly charges relative to volumetric charges as a result of this proceeding.

IV. CONCLUSIONS AND RECOMMENDATIONS

Q. WHAT ARE YOUR RECOMMENDATIONS REGARDING THE PROPOSED REVENUE DISTRIBUTION FOR THE COMPANY?

A. In light of the Company having no cost basis, either in the current proceeding or prior proceedings, for which to allocate the proposed revenue increase between rate

classes, I agree with the Company's proposed equal allocation of its proposed revenue increase in the current proceeding.

Q. WHAT ARE YOUR CUSTOMER CHARGE RECOMMENDATIONS AND CONCLUSIONS?

A. I recommend that the Commission reject the Company's proposed increase in customer charges since the Company has no cost basis for its proposed customer charges. The Company's current residential and commercial customer charges are similarly near the average of other similarly situated natural gas distribution utilities in the region. Finally, the proposal would negatively impact the public policy goals of energy efficiency and would burden low-use customers with a greater than average portion of any proposed increase in the case.

Q. DO YOU HAVE AN ALTERNATIVE RECOMMENDATION IF THE COMMISSION DETERMINES AN INCREASE IN THE COMPANY'S CUSTOMER CHARGE IS WARRANTED?

A. Yes. If the Commission determines that increases in the Company's customer charges are warranted, I recommend that the Commission cap these increases to no more than the overall system average increase. This will prevent Company rates from becoming more reliant on fixed monthly charges relative to volumetric charges as a result of this proceeding.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

Michael William Deupree
Research Consultant
Acadian Consulting Group
5800 One Perkins Place Drive, Suite 5-F
Baton Rouge, LA 70808

EDUCATION

M.A. in Economics, Kansas University, 2009

B.A. in Business Economics, Buena Vista University, 2007

PROFESSIONAL EXPERIENCE

Acadian Consulting Group, Baton Rouge, Louisiana

Spring 2025 – Present	Senior Research Consultant
Summer 2021 – Spring 2025	Research Consultant
Summer 2016 – Summer 2021	Research Associate
Winter 2011 – Summer 2016	Senior Research Analyst

Kansas Corporation Commission, Topeka, Kansas

Utilities Division

Summer 2011 – Winter 2011	Senior Research Economist

Research Division

Spring 2009 – Summer 2011	Research Analyst

Kansas Energy Council

Summer 2008 – Spring 2009	Research Assistant

PUBLICATIONS AND REPORTS

1. The challenges of the regulatory review of diversification mergers. With Dr. David E. Dismukes. *The Electricity Journal* 29 (2016) 8-14. (May 2016)

PROFESSIONAL AND CIVIC PRESENTATIONS

1. "Natural Gas Distribution" (2025). Prepared for the Louisiana State University, Center for Energy Studies, Energy Fundamentals 2025. June 24 and July 8, 2025.

2. "Development Trends, Issues, and Challenges with Clean Hydrogen Production" (2025). Prepared for the Michigan State University, Institute of Public Utilities, Annual Regulatory Studies Program. April 15, 2025.

3. "Status and Future of Natural Gas Supply and Infrastructure" (2025). Prepared for the Michigan State University, Institute of Public Utilities, Annual Regulatory Studies Program. April 8, 2025.

4. "Observed Impact of Formula Rate Plans Across the United States" (2024). Prepared for Arizona Corporation Commission Formula Rate Plan Workshop. October 3, 2024.

EXPERT WITNESS, LEGISLATIVE, AND PUBLIC TESTIMONY; EXPERT REPORTS, RECOMMENDATIONS, AND AFFIDAVITS

1. Expert Testimony. Cause No. 46120. (2025). Before the Indiana Utility Regulatory Commission. *Verified Petition of NIPSCO Generation LLC for Certain Determinations by the Commission with Respect to its Jurisdiction Over Petitioner's Activities as a Non-Retail Generator of Electric Power.* On Behalf of the Indiana Office of Utility Consumer Counselor. Issues: Rate Design, Large Data Center Loads.

2. Expert Testimony. Case No. U-21859. (2025). Before the Michigan Public Service Commission. *In the matter of the application of Consumers Energy Company for Ex Parte Approval of Certain Amendments to Rate GPD.* On Behalf of the Michigan Attorney General. Issues: Rate Design, Large Data Center Loads.

3. Expert Testimony. Docket No. R-2025-3053112. (2025). Before the Pennsylvania Public Utilities Commission. *Pennsylvania Public Utility Commission v. Philadelphia Gas Works.* On Behalf of the Pennsylvania Office of Consumer Advocate. Issues: Decoupling, Regulatory Lag.

4. Expert Testimony. Docket No. E-01773A-24-0220. (2025). Before the Arizona Corporation Commission. *In the Matter of the Application of Arizona Electric Power Cooperative, In. for a Hearing to Determine the Fair Value of its Property for Ratemaking Purposes, to Fix a Just and Reasonable Return Thereon and To Approve Rates Designed to Develop Such Return.* On Behalf of Arizona Corporation Commission Staff. Issues: Cost of Service, Qualifying Facilities.

5. Expert Testimony. Case No. U-21816. (2025). Before the Michigan Public Service Commission. *In the matter of Consumer Energy Company's application for the regulatory reviews, revisions, determinations, and/or approvals necessary to fully comply with Public Act 295 of 2008, as amended by Public Act 235 of 2023.* On Behalf of the Attorney General. Issues: Capital Expense, Cost Recovery

6. Expert Testimony. Cause No. 46120. (2024). Before the Indiana Utility Regulatory Commission. *Petition of Northern Indiana Public Service Company LLC Pursuant to Ind. Code §§ 8-1-2-42.4, 8-1-2-61 and 8-1-2.5-6 for (1) Authority to Modify its Retail Rates and Charges for Electric Utility Service Through a Phase in of Rates;*

(2) Approval of New Schedules of Rates and Charges, General Rules and Regulations, and Riders (both Existing and New); (3) Approval of Revised Common and Electric Depreciation Rates Applicable to its Electric Plant in Service; (4) Approval of Necessary and Appropriate Accounting Relief, Including, but Limited to, Authority to Capitalize as Rate Base All Expenditures for Improvements to Petitioner's Information Technology Systems through the Design, Development, and Implementation of a Work and Asset Management ("WAM") Program, to the Extent Necessary; and (5) Approval of Alternative Regulatory Plans for the Partial Waiver of 170 IAC 4-1-16(f) and Proposed Remote Disconnection and Reconnection Process and, to the Extent Necessary, Implementation of a Low Income Program. On Behalf of the Indiana Office of Utility Consumer Counselor. Issues: Cost of Service, Rate Design.

7. Expert Testimony. Cause No. 46097. (2024). Before the Indiana Utility Regulatory Commission. *In the Matter of the Verified Petition of Indiana Michigan Power Company for Approval of Modifications to its Industrial Power Tariff – Tariff I.P.* On Behalf of the Indiana Office of Utility Consumer Counselor. Issues: Rate Design, Large Data Center Loads.

8. Expert Report. Docket No. AHD-00000J-23-0273. (2024). Before the Arizona Corporation Commission. *In the Matter of the Application of the Arizona Corporation Commission's Exploration of Changes to the Up to 10% Annual Reduction in the Export Rate and the 10-Year Export Rate Effective Period Under the Resource Comparison Proxy Methodology Approved in the Value and Cost of Distributed Generation Docket (E-00000J-14-0023).* On Behalf of the Arizona Corporation Commission Staff. Issues: Value of Solar.

9. Expert Testimony. Case No. U-21585. (2024). Before the Michigan Public Service Commission. *In the Matter of the Application of Consumers Energy Company for Authority to Increase its Rates for the Generation and Distribution of Electricity and Other Relief.* On Behalf of the Attorney General. Issues: Capital Expenses.

10. Expert Report. *Review of LPSC Rules Regarding Distributed Generation: Report on Phase II of Rule-Making.* Docket No. R-33929. (2019). *In Re: Review of Policies Related to Customer-owned Solar Generation and Possible Modification of the Commission's Current Net Metering Rules.* On behalf of Louisiana Public Service Commission. Issues: Solar Net Metering.

11. Expert Report. (2011). *2011 Kansas Generation Planning Survey*. On behalf of the Kansas Corporation Commission Staff.

12. Expert Testimony. Docket No. 11-KCPE-581-PRE. (2011). Before the Kansas Corporation Commission. *In the Matter of the Petition of Kansas City Power & Light Company ("KCP&L") for Determination of the Ratemaking Principles and Treatment That Will Apply to the Recovery in Rates of the Costs to be Incurred by KCP&L for Certain Electric Generation Facilities Under K.S.A. 66-1239.* On Behalf

of the Kansas Corporation Commission Staff. Issues: System Planning, Predetermination.

13. Expert Testimony. Docket No. 10-KCPE-795-TAR. (2010). Before the Kansas Corporation Commission. *In the Matter of the Application of Kansas City Power & Light Company for Approval to Implement a Portfolio of Demand Side Management Programs Including Affordability, Energy Efficiency, Demand Response and Educational Programs, and to Implement a Rider for Recovery of Program Costs and Incentives Associated with this Portfolio.* On Behalf of the Kansas Corporation Commission Staff. Issues: Demand Side Management, Cost-Benefit Analyses.

14. Expert Testimony. Docket No. 10-WSEE-775-TAR. (2010). Before the Kansas Corporation Commission. *In the Matter of the Application of Westar Energy, Inc. and Kansas Gas and Electric Company for an Order Authorizing them to participate in Efficiency Kansas, Approve the SimpleSavings Program Rider, and related cost recovery.* On Behalf of the Kansas Corporation Commission Staff. Issues: Demand Side Management, Cost-Benefit Analyses.

15. Expert Testimony. Docket No. 10-BHCG-639-TAR. (2010). Before the Kansas Corporation Commission. *In the Matter of the Application of Black Hills/Kansas Gas Utility Company, LLC, d/b/a Black Hills Energy for Approval to Implement Black Hills Energy's Five-Year Energy Efficiency Plan Consisting of Natural Gas Energy Efficiency Programs to Improve Building and Equipment Efficiency and to Educate About Efficient Energy Usage, to Provide for Program Cost Recovery Through a Rider Mechanism, Permit the Implementation of a Revenue Normalization Mechanism to Replace the Weather Normalization Adjustment, a Performance Incentive Mechanism, and Appropriate Accounting Authority to Defer Expenses and Revenues Associated with the Filing.* On Behalf of the Kansas Corporation Commission Staff. Issues: Demand Side Management, Cost-Benefit Analyses.

16. Expert Testimony. Docket No. 10-EPDE-497-TAR. (2010). Before the Kansas Corporation Commission. *In the Matter of the Application of the Empire District Electric Company for Approval to Implement its Portfolio of Energy Efficiency and Demand Response Programs for its Kansas Customers, to Provide for Program Cost Recovery and Lost Revenue Through a Rider Mechanism, to Obtain any Necessary Waivers for the Commission, and for Appropriate Accounting Authority to Defer Expenses and Revenues Associated with the Filing.* On Behalf of the Kansas Corporation Commission Staff. Issues: Demand Side Management, Cost-Benefit Analyses.

17. Expert Testimony. Docket No. 10-KGSG-421-TAR. (2010). Before the Kansas Corporation Commission. *In the Matter of the Application of Kansas Gas Service, a Division of ONEOK, Inc., for Approval to Implement the Efficiency Kansas Energy Efficiency Program, to Implement Natural Gas Energy Efficiency Programs to Improve Building and Equipment Efficiency and to Educate about Efficient Energy*

Usage, To Provide for Program Cost Recovery Through a Rider Mechanism, to Establish Administrative Charges and a Program Initiation Fee, Permit the Implementation of a Revenue Decoupling Mechanism, and Appropriate Accounting Authority to Defer Expenses and Revenues Associated with the Filing. On Behalf of the Kansas Corporation Commission Staff. Issues: Demand Side Management, Cost-Benefit Analyses.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No. R-2025-3054393
	:	
Valley Energy, Inc.	:	
	:	

VERIFICATION

I, Michael Deupree, hereby state that the facts above set forth in my Direct Testimony, OCA Statement No. 3, are true and correct to the best of my knowledge, information, and belief and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa.C.S. § 4904 (relating to unsworn falsification to authorities).

DATED: July 15, 2025

Signature:

Michael Deupree

Address: Acadian Consulting Group
5800 One Perkins Place Drive
Suite 5-F
Baton Rouge, LA 70808

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	Docket No.: R-2025-3054392
v.	:	
	:	
Wellsboro Electric Company	:	

DIRECT TESTIMONY

OF

Michael Deupree

On behalf of the

PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

OCA Statement 3

Date Served: July 15, 2025

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I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS?

A. My name is Michael W. Deupree. My business address is 5800 One Perkins Place Drive, Suite 5-F, Baton Rouge, Louisiana, 70808.

Q. PLEASE STATE YOUR OCCUPATION AND CURRENT PLACE OF EMPLOYMENT?

A. I am a Senior Research Consultant with the Acadian Consulting Group ("ACG"), a research and consulting firm that specializes in the analysis of regulatory, economic, financial, accounting, statistical, and public policy issues associated with regulated and energy industries. ACG is a Louisiana-registered partnership, formed in 1995, and is located in Baton Rouge, Louisiana.

Q. PLEASE DESCRIBE YOUR PROFESSIONAL QUALIFICATIONS.

A. I hold a Bachelor of Arts degree in Business Economics from Buena Vista University in Storm Lake, Iowa, and a Master of Arts degree in Economics from the University of Kansas in Lawrence, Kansas. I began my professional career with the Staff of the Kansas Corporation Commission in 2008 while in graduate school conducting analyses of topics related to energy and economy as a Research Assistant, eventually being promoted to a Research Analyst and later Senior Research Economist after graduation. I left the Kansas Corporation Commission to take a position with ACG in late 2011, where I have been promoted to positions of increasing responsibility since, including my current position which I started in mid-2021. At ACG I managed research teams supporting expert testimony and have overseen dozens of litigated preceding, including multiple proceedings on behalf of the AG. Appendix A provides my professional

resume, which includes a listing of my publications, presentations, pre-filed expert witness testimony, expert reports, and expert legislative testimony.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I have been retained by the Pennsylvania Office of the Consumer Advocate ("OCA") to address matters related to the general rate case filed by Wellsboro Electric Company ("Wellsboro" or the "Company"). I specifically have been asked to review the Company's proposed Allocated Cost of Service Study ("ACOS") and rate design.

Q. ARE YOU SPONSORING ANY EXHIBITS?

A. Yes. I am sponsoring the following Exhibits MWD-1 (Wellsboro) through MWD-4 (Wellsboro).

- Exhibit MWD-1: Summary of Results of Company's Proposed ACOS
- Exhibit MWD-2: Summary of Results of Alternative ACOS
- Exhibit MWD-3: Summary of Company's Proposed Revenue Allocation
- Exhibit MWD-4: Summary of Results of Alternative Revenue Allocation

II. SUMMARY OF RECOMMENDATIONS

Q. WHAT ARE YOUR ACOS FINDINGS FOR WELLSBORO?

A. My alternative ACOS analysis shows that the Company's incorrect classification of secondary-voltage distribution plant skews the allocation of costs and revenue responsibilities away from larger customers and onto residential and small commercial customers. I recommend the Commission rely on the results of my alternative ACOS as

a fair and reasonable estimation of relative costs of service between Company customer classes.

Q. WHAT IS YOUR RECOMMENDATION REGARDING WELLSBORO'S PROPOSED REVENUE DISTRIBUTION?

A. I recommend that the Commission adopt a more reasonable revenue distribution allocation method based on my alternative ACOS results that also limits the rate increase to the non-residential heating ("NRH"), commercial space heating ("CSH"), and residential service-all electric ("RSAE") customer classes to 1.25 times the overall system average increase. Under Wellsboro's proposed overall distribution revenue increase of 45.3 percent this reduces the revenue increase to these rate classes to 56.61 percent, compared to the Company's proposed distribution rate increases of 75.0 percent for the NRH and CSH classes, and 60.52 percent for the RSAE class.

Q. WHAT IS YOUR RECOMMENDATION REGARDING WELLSBORO'S PROPOSED RATE DESIGN FOR CUSTOMER CHARGES?

A. I recommend the Commission reject Wellsboro's proposed increases in customer charges because they disproportionately impact low-income customers and reduce customer incentives to reduce usage, contrary to public goals of promoting energy efficiency. Furthermore, Wellsboro's existing residential customer charge is the third highest and the proposed increase would make the charges the highest among regional peer investor-owned utilities. Finally, a correct analysis of customer-related costs from Wellsboro's ACOS finds that all residential and commercial rate classes are currently recovering *nearly all* customer-related costs through monthly customer charges.

Q. DO YOU HAVE AN ALTERNATIVE RECOMMENDATION IF THE COMMISSION DECIDES AN INCREASE IN MONTHLY CUSTOMER CHARGES IS WARRANTED?

A. Yes. I recommend that the Commission limit its increase in Wellsboro monthly customer charges to only that required to bring the Company's customer charges in line with Citizens' Electric Company. This would increase the residential customer charge to $13.10 per month.

III. ALLOCATED COST OF SERVICE STUDY

A. Introduction

Q. WHAT IS THE PURPOSE OF AN ACOS?

A. An ACOS is a modeling approach that reconciles utility costs and revenues across different customer classes. The goal of an ACOS is to evaluate the cost of providing service and revenue responsibility for each individual customer class. ACOS results are used to estimate class specific rates of return and can serve as a guidepost for class revenue responsibilities and ultimately rates.

Q. HOW IS AN ACOS PREPARED?

A. An ACOS utilizes a set of historic or projected cost information that is (1) functionalized, (2) classified, and (3) allocated. The functionalization process simply categorizes costs based upon the functions they serve within a utility's overall operations (i.e. production, transmission, and distribution). The classification process characterizes costs by type, including those that are (1) demand-related, (2) energy/commodity-related, or (3) customer-related. The last step of the process allocates each of these costs to a respective jurisdiction or customer class as appropriate.

Q. PLEASE EXPLAIN DEMAND-RELATED COSTS.

A. Demand-related costs are associated with meeting maximum electricity demands. At the distribution level, electric substations and line transformers are designed, in part, to meet the maximum customer demand requirements. The most common demand allocation factors used in an ACOS are those related to system Coincident Peaks ("CP") or Non-Coincident Peaks ("NCP"). At the production level, most power plants, also referred to as production plants or electric generation units ("EGU"), are typically viewed as being designed to serve both the energy/commodity and demand/capacity needs of the utility. The exact degree of this split between energy and demand depends on the individual EGU in question and how that unit is dispatched with baseload units serving more of the utility's energy needs and peak units serving more of the utility's capacity or demand needs. Therefore, it is not uncommon to develop composite energy and demand allocators to allocate plant-in-service costs associated with a utility's generation fleet.

Q. HOW ARE ENERGY-RELATED COSTS DEFINED?

A. Energy-related costs are defined as those that tend to change with the amount or volume of electricity (i.e., kilowatt-hour ("kWh")) sold. Electric generation costs and high-voltage transmission lines, for instance, can be allocated, in part, based on some measure of electricity sales.

Q. WHAT ABOUT CUSTOMER-RELATED COSTS?

A. Customer-related costs are those associated with connecting customers to the distribution system, metering household or business usage, and performing a variety of other customer support functions.

Q. IS THIS A RELATIVELY SIMPLE PROCESS?

A. No. Some costs can be clearly identified and directly assigned to a function, while other costs are more ambiguous and difficult to assign. The primary challenge in conducting a ACOS is the treatment of what are known as “joint and common” costs. Given their shared or integrated nature, these joint and common costs can often be difficult to compartmentalize. Therefore, unique allocation factors are utilized in a ACOS to classify joint and common costs. The process of developing these cost allocation factors can become subjective and is often imbued with policy considerations.

Q. HOW DOES AN ACOS RELATE TO COMMONLY QUOTED ECONOMIC PRINCIPLES?

A. An ACOS is referred to as a “fully allocated cost study” since it allocates test year revenues, rate base, expenses, and depreciation to various jurisdictions and customer classes based upon a series of different allocation factors. The purpose of the ACOS is to develop cost responsibility estimates for each customer class, which in turn, can be used to develop rates. An ACOS is based upon a set of historic utility book costs that have accumulated over decades. Rates are, therefore, based upon historic average costs, whereas economic theory suggests that the most efficient form of pricing in perfectly competitive markets should be based upon marginal costs. However, regulated utilities do not operate in perfectly competitive markets and, by their very nature, are natural monopolies. Thus, reaching the ideal pricing formula outlined in economic theory is impossible since the nature of natural monopolies makes pricing in the presence of declining average costs, coupled with the presence of joint and common costs, difficult.

Q. ARE THERE ANY OTHER CONFOUNDING PROBLEMS THAT CAN ARISE WITH AN ACOS?

A. Yes. The problems listed above are confounded by the fact that the cost information utilized in an ACOS is usually historic and static, or based on potentially inaccurate projections in the context of Fully Projected Future Test Years ("FPFTY"). These analytic deficiencies undermine many experts' cost causation/pricing claims. As a result, in regular practice there is no single correct answer that is revealed in an ACOS. It is often up to regulators to exercise an appropriate level of judgment regarding the nature of these costs, the results of the ACOS, and the implications both have in setting fair, just, and reasonable rates. This is one of the reasons why many regulators use ACOS results as a "guide" in setting rates and do not consider themselves unnecessarily bound by the ACOS results.

Q. WHAT CONTROVERSIES ARISE IN THE ANALYSIS AND COMPARISON OF VARIOUS ACOS METHODOLOGIES?

A. The ACOS process is significantly different from the revenue requirement or cost of capital phase of a typical rate case. While the latter two processes focus on determining how much revenue will be recovered through rates, the ACOS process determines how those costs (revenue requirements) will be recovered through customer rates. The primary controversy with the evaluation of various ACOS results often rests with determining whether costs (revenue requirements) will be recovered by the relative customer share of each class, the peak load contributions of each customer class, or whether and how the approach will be tempered through the use of customer, peak, and off-peak usage considerations. Methodologies that are heavily skewed toward customer and peak considerations, for instance, can shift costs more than proportionally to relatively lower load-factor customers, such as residential and small commercial

customers, and less costs to larger high load factor customer classes and off-peak customers. These approaches can also fail to capture the service being provided by the utility (i.e., electric service in this case), and how the value of that service varies by the amount purchased by different customer classes.

Q. PLEASE EXPLAIN THE BIAS IN METHODOLOGIES THAT ARE SKEWED TOWARD PEAK CONSIDERATIONS.

A. Residential and small commercial customer electricity loads are typically weather sensitive. On the other hand, larger industrial customers use electricity in processes that are generally not weather sensitive, and electric use thus tends not to cycle up and down, but rather runs on a more continuous basis. Because of this, daily and annual usage patterns for these two customer classes are significantly different. The peak loads for residential and small commercial customers tend to be more “peaked” than those for industrial customers, which are steadier and more evenly distributed across peak and non-peak hours. For example, an average residential customer may have relatively little electricity use during overnight hours and during weekday daytime working hours. Residential customers exhibit relatively significant use during early summer evening hours corresponding to returning home from work, and potentially during chilly early winter morning hours if the customer uses electric resistance heating. Similarly, small commercial customers see limited electricity use outside of workday hours. Thus, residential and small commercial customers tend to have relatively lower load factors than large industrial customers.

Q. PLEASE DEFINE “LOAD FACTOR.”

A. A load factor is defined as the ratio of the average load in kilowatt hours supplied during a designated period to the peak or maximum load in kilowatts occurring in that period. The load factor is expressed as a percentage and may be derived by taking the energy used during a period and dividing it by the product of the maximum demand and the number of hours in the period. A system that is estimated to have a high load factor is often thought to be utilizing electricity more efficiently, since usage is consistent and does not swing significantly between average and peak periods. Conversely, systems with low load factors must maintain idle capacity in order to meet the relatively large swings in load between average and peak periods.

Q. DOES A HIGH LOAD FACTOR INDICATE GREATER SYSTEM EFFICIENCY?

A. Yes, since a higher system load factor can be indicative of, or lead to better system resource utilization, other things being equal. However, it should be recognized that all utilities inherently have customers with different load profiles due to differences in how customers use electricity. Furthermore, the development of integrated wholesale bulk electricity transmission systems has allowed utilities to collectively diversify generation resources and individual system demands, which has reduced the impact of individual system load characteristics on generation needs in recent years. While rates should recognize and promote the efficient utilization of utility system resources, caution should be used in placing too much emphasis on this principle of rewarding high load factor industrial customers to the detriment of low load factor residential and small commercial customers.

Q. WHAT IMPACT DOES COST ALLOCATION HAVE ON REVENUE RECOVERY?

A. Higher use customers, such as industrial customers, are inherently more price sensitive than lower use customers due to the relative impact increases in rates can have on these customers' total utility bills and the margins of produced goods. These higher use industrial customers tend to have more energy supply alternatives, including fuel switching and self-generation, which is part of the reason why they are more price sensitive. These considerations can result in differences in revenue generation given the differences in the price elasticities of demand (i.e., price sensitivities) for the two sets of customers (residential, industrial).

Q. EXPLAIN HOW SOME ACOS METHODS CAN BE BIASED AGAINST LOWER LOAD-FACTOR CUSTOMERS.

A. Utilities by their nature are capital intensive industries with high levels of capital expenditures required to develop systems to generate and transmit power to customers. Therefore, deciding the appropriate allocation of costs associated with utility capital investments (e.g., utility "plant in service") largely affects the cost of providing service. Utilities can often over-emphasize peak demand factors in allocating these large plant costs in order to assign more costs away from their price sensitive customers. Likewise, utilities can emphasize non-diversified single CP demands, NCP demands, and individual customer demands in allocating costs associated with transmission and distribution plant facilities to favor high-load factor customers relative to low-load factor customers. Finally, utilities can over-emphasize customer connection aspects of lower voltage distribution facilities to favor high-use customers relative to low-use customers.

B. Overview of Company's ACOS

Q. PLEASE DESCRIBE WELLSBORO'S ACOS APPROACH.

A. The Company states that it developed its ACOS with four goals in mind: (1) recognition of cost causality as opposed to value of service, (2) stability of results over time, (3) logical consistency and completeness, and (4) ease of implementation.[1] To this end the Company utilizes the traditional three-step approach to ACOS. First the Company functionalizes its costs to six separate functions: supply; transmission; sub-transmission; primary distribution; secondary distribution; and billing.[2] Second, the Company classifies these functionalized costs to two separate purposes: demand and customer costs.[3] Finally, the Company defines a series of individual allocators to allocate these functionalized and classified costs to individual rate classes.[4]

Q. PLEASE EXPLAIN HOW THE COMPANY CLASSIFIES ITS DISTRIBUTION PLANT INVESTMENTS.

A. The Company classifies all distribution plant investment costs as either customer- or demand-related, or a combination of these two factors.[5] The Company utilized what it refers to as a "zero-load analysis" to define a portion of secondary distribution system costs associated with utility poles (FERC Account 364), overhead conductors (FERC Account 365), underground conductors (FERC Account 366), underground conduit (FERC Account 367), and line transformers (FERC Account 368) as partially customer-

[1] Direct Testimony of Howard S. Gorman at 15:6-13.

[2] Direct Testimony of Howard S. Gorman at 16:13-14, and Company Response to OCA-I-1, Attachment A.

[3] Direct Testimony of Howard S. Gorman at 16:14-15, and Company Response to OCA-I-1, Attachment A.

[4] Direct Testimony of Howard S. Gorman at 16:15-16, and Company Response to OCA-I-1, Attachment A.

[5] Company Response to OCA-I-1, Attachment A.

related, while classifying all other non-customer-related distribution as fully demand-related.[6]

Table 1: Summary of Results of Company's ACOS

	Total Citizens	Residential Service: Residential (RS)	Residential Service: All Electric (RSAE)	Commercial and Industrial Service: Non-Residential (NRS)	Commercial and Industrial Service: Non-Res. Heating (NRH)	Commercial and Industrial Service: Commercial (CS)	Commercial and Industrial Service: Comm. Heating (CSH)	Commercial and Industrial Service: Industrial (IS)	Lighting Service: Municipal (MBL)	Lighting Service: Outdoor (OL)	Exchange Service (EU)
Net Operating Income											
Total Operating Revenues	$ 6,729,636	$ 3,547,282	$ 26,544	$ 515,600	$ 794	$ 1,598,472	$ 1,264	$ 934,576	$ 13,712	$ 82,233	$ 9,159
Total Operating Expenses	6,554,566	3,888,535	35,071	549,279	2,051	1,284,977	3,966	759,003	7,527	16,840	7,317
Net Operating Income	**$ 175,070**	**$ (341,253)**	**$ (8,527)**	**$ (33,679)**	**$ (1,257)**	**$ 313,495**	**$ (2,702)**	**$ 175,573**	**$ 6,185**	**$ 65,393**	**$ 1,842**
Total Rate Base	**$25,857,279**	**$14,330,403**	**$ 143,611**	**$ 1,883,819**	**$ 9,415**	**$ 5,706,466**	**$ 19,138**	**$3,491,939**	**$111,717**	**$138,165**	**$ 22,606**
Rate of Return on Rate Base	**0.68%**	**-2.38%**	**-5.94%**	**-1.79%**	**-13.35%**	**5.49%**	**-14.12%**	**5.03%**	**5.54%**	**47.33%**	**8.15%**
Relative Rate of Return (RRO	**1.00**	**-3.52**	**-8.77**	**-2.64**	**-19.72**	**8.11**	**-20.85**	**7.43**	**8.18**	**69.90**	**12.03**

Q. HAVE YOU EXAMINED THE COMPANY'S ACOS RESULTS?

A. Yes. Exhibit MWD-1 (Wellsboro), summarized in Table 1 above, presents the results of the Company's ACOS which estimates an overall FPFTY rate of return ("ROR") of current rates of 0.68 percent. Estimated individual class returns range from negative 14.12 percent for the commercial space heating or CSH class to 47.33 percent for the outdoor lighting ("POL") class. The residential service ("RS") rate class is estimated by the Company to achieve an ROR of negative 2.38 percent during the test year under current rates, which is negative 3.52 of the system average on a relative rate of return ("RROR") basis.

Q. DO YOU DISAGREE WITH ANY OF THE ASSUMPTIONS OR ALLOCATION FACTORS INCORPORATED IN THE COMPANY'S PROPOSED ACOS?

A. Yes. I disagree with the Company's reliance on the results of its zero-load analysis and minimize size analysis to classify secondary distribution plant assets as being partially customer-related. The Company's zero-load analysis for secondary distribution plant other than transformers and minimum size analysis for transformers are forms of

[6] Direct Testimony of Howard S. Gorman at 16:10-11, and Company Response to I&E-RE-1D, Attachment A.

what is referred to as a Minimum System Study ("MSS") that are not aligned with cost-causation.

C. Use of a "Minimum System Study" to Classify Distribution Plant Costs

Table 2: Summary of Results of Company's Zero-Load Analysis

FERC Account Description	Demand Allocation	Customer Allocation
364 Secondary Poles, Towers and Fixtures	36.96%	63.04%
365 Secondary Overhead Conductors and Devices	43.97%	56.03%
366 Secondary Underground Conduit	63.71%	36.29%
367 Secondary Underground Conductors and Devices	63.71%	36.29%
368 Secondary Line Transformers	22.45%	77.55%

Source: Company's Response to I&E-RE-1-D, Attachment A.

Q. PLEASE DESCRIBE HOW THE COMPANY CLASSIFIES THE CUSTOMER AND DEMAND COMPONENTS OF ITS SECONDARY-VOLTAGE DISTRIBUTION PLANT COSTS.

A. The Company's witness Mr. Gorman conducted an zero load analysis to determine the customer-related component of secondary-voltage distribution system costs included in FERC Account 364 – Overhead Electric Poles; FERC Account 365 – Overhead Conductors; FERC Account 366 – Underground Conductors; FERC Account 367 – Underground Conduits; and a minimum size analysis to determine the customer-related component of secondary-voltage transformer costs included in FERC Account 368 – Line Transformers.[7] Table 2 presents a summary of the results of the Company's zero load and minimum size analyses. The Company's zero load and minimum size analyses

[7] Direct Testimony of Howard S. Gorman at 20:5 to 21:3, and Company Response to I&E-RE-1D, Attachment A.

estimates customer-related classification from a low of 36.29 percent (FERC Account 366) to a high of 77.55 percent (FERC Account 368).[8]

Q. PLEASE DESCRIBE THE ZERO-LOAD ANALYSIS MR. GORMAN USES TO ESTIMATE THE CUSTOMER-RELATED PORTION OF UPSTREAM SECONDARY DISTRIBUTION PLANT OTHER THAN LINE TRANSFORMERS.

A. Mr. Gorman examined the total inventory of Citizens' poles, overhead conductors and underground conductors.[9] He then examined what appears to be the cost that would be required to replace this inventory based on recent workorders, separating these expenses into four categories: Labor, Overhead, Vehicle, and Materials.[10] All non-materials costs were viewed as labor-related (i.e. Labor, Overhead, and Vehicle expenses) and classified as customer-related with the balance being defined as demand-related.[11] As Mr. Gorman states in this proceeding, "The zero-load component of the Secondary system represents the cost of extending service to all customers, without regard to peak or average load, and is therefore customer-related."[12] Since this "zero-load component" has no load-carrying capacity, no adjustment to the demand allocators is proposed by Mr. Gorman.

Q. PLEASE DESCRIBE MR. GORMAN'S "MINIMUM SIZE ANALYSIS" FOR CLASSIFYING A PORTION OF LINE TRANSFORMERS AS CUSTOMER-RELATED.

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[8] Company Response to I&E-RE-1D, Attachment A.

[9] *Id.*

[10] *Id.*

[11] Direct Testimony of Howard S. Gorman at 20:10-13.

[12] Direct Testimony of Howard S. Gorman at 20:5-18.

A. Similar to his zero-load analysis, Mr. Gorman first examined the total inventory of Citizens' line transformers. He then claims he defined a minimum size transformer of 10 kilovolt amperes ("kVa") serving one customer.[13] Finally, Mr. Gorman multiplied this minimum size transformer cost by the number of line transformers on the system to arrive at the portion of total line transformer costs that he defines as customer-related.[14]

Q, DO YOU AGREE WITH MR. GORMAN'S ZERO-LOAD ANALYSIS FOR SECONDARY PLANT OTHER THAN TRASNFORMERS OR MINIMUM SIZE ANALYSIS FOR TRANSFORMERS?

A. No. As stated, both Mr. Gorman's zero-load analysis and minimum size analysis are forms of a MSS that are not aligned with cost-causation, which I explain more fully below, and I disagree with Mr. Gorman's reliance on the results of his zero-load analysis and minimum size analysis to classify secondary distribution plant assets as being partially customer-related.

Q. PLEASE EXPLAIN THE THEORETICAL BASIS FOR A "MINIMUM SYSTEM" STUDY OR MSS.

A. Such studies are often advocated by those holding the view that certain distribution plant investments are made to serve a dual-nature: one consisting of meeting system load requirements, the other being focused on customer interconnection or access that requires a customer-based allocation component. This minimum system component is

[13] Direct Testimony of Howard S. Gorman at 20:20-21.

[14] Direct Testimony of Howard S. Gorman at 20:20-21.

determined through an MSS (referred to by the Company as a 'zero load analysis') or a related Zero-Intercept Study.

Q. WHAT ARE MSS AND ZERO-INTERCEPT STUDIES?

A. MSS and zero-intercept studies are cost allocation methodologies that attempt to estimate separate customer-related versus load-related costs. An MSS does this by estimating the hypothetical costs of developing a "minimum" system that only provides customers with connection to a utility's electric distribution system but not a system sufficient to actually serve the customer's electrical requirements. Likewise, a zero-intercept study utilizes regression analysis techniques to estimate the relationship between the electric demand requirements on a system and costs associated with installation of new distribution plant assets. Using these regression analyses, a zero-intercept study then calculates a hypothetical minimum cost by calculating the costs of the distribution plant assets given zero demand requirements.

Q. PLEASE DESCRIBE THE MECHANICS OF AN MSS.

A. It is argued that many distribution system assets can be classified as having both a customer and a demand component. For instance, distribution substations are built to serve customers but are often expanded to meet increases in customer loads. An MSS study attempts to separate the customer-related portion of total system costs from those associated with serving loads (or service volumes). An MSS study estimates the hypothetical costs of developing a minimum system to serve customers with no load. These calculations involve subjectivity since they use accounting and engineering analyses to develop assumptions about the minimum sizes and costs associated with various distribution system components, while still satisfying system requirements such

as pole height and efficient conductor and transformer sizes. The costs associated with these "minimum" components are then added together to derive the total minimum costs associated with the hypothetical system with no energy usage. This estimate is then divided by total actual system costs to approximate the customer-related share of overall distribution system costs.

Q. ARE THERE ANY THEORETICAL SHORTCOMINGS TO USING MSS AND ZERO-INTERCEPT STUDIES FOR CLASSIFICATION OF DISTRIBUTION PLANT ASSETS?

A. Yes. Both MSS and zero-intercept studies depend on deeply flawed counterfactual theoretical premises. MSS-based analyses deal in hypotheticals that do not exist in the real world, including the assumption that somehow there is an electric distribution system out there in the world that could or would be plausibly built to serve customers but not load. No such system exists, making the underlying assumptions and modeling of a "minimum system" difficult, if not impossible, to verify. Even if a minimum electric distribution system could be constructed in real life, it would still have the ability to service at least a portion of customers' loads, undermining this modeling approach's fundamental premise.

Q. DOES THE NARUC COST ALLOCATION MANUAL RECOGNIZE THESE CHALLENGES?

A. Yes. The National Association of Regulatory Utility Commissioners ("NARUC") Electric Cost Allocation Manual ("NARUC Manual") recognized this fundamental failing of MSS approaches in its discussion of the approach:

> Cost analysts disagree on how much of the demand costs should be allocated to customers when the minimum-size

> distribution method is used to classify distribution plant. When using this distribution method, the analyst must be aware that the minimum-size distribution equipment has a certain load-carrying capability, which can be viewed as a demand-related cost.[15]

Q. WHAT ARE THE THEORETICAL FAILINGS OF ZERO-INTERCEPT BASED STUDIES?

A. A zero-intercept-based approach is simply a statistically based MSS approach and suffers, conceptually, from the same shortcomings. A zero-intercept analysis attempts to model an empirical relationship that does not exist. One should recognize that the argument that electric distribution costs are related to the number of customers on a utility's system is not a new argument, and the academic literature in utility regulation has questioned for quite some time the use of both MSS and zero-intercept studies.

Q. HOW HAS THE ACADEMIC LITERATURE IN UTILITY REGULATION QUESTIONED THE USE OF MSS AND ZERO-INTERCEPT STUDIES?

A. Dr. James Bonbright, in his seminal work on public utility regulation, published originally in the 1970s, raises a number of questions about the use of MSS and zero-intercept methodologies in classifying costs. Dr. Bonbright's primary concern was the lack of empirical support in the academic literature for a causal relationship between distribution system costs and the number of customers. The true driving factors of utility distribution system costs are much more complicated and depend on a host of other factors, such as the size of a service territory and the population density within. The incremental cost of constructing an appropriate distribution system to serve an additional

[15] Electric Utility Cost Allocation Manual (January 1992), NARUC, p. 95.

customer within an urban area with existing nearby infrastructure is substantially less than the cost to extend an existing utility system by potentially miles to serve an additional customer located in a rural area, a fact inherently ignored by MSS and zero-intercept methodologies:

> …the annual costs of this phantom, minimum-sized distribution system are treated as customer costs and are deducted from the annual costs of the existing system, only the balance being included among those demand-related costs to be mentioned in the following section. Their [minimum distribution costs] inclusion among the customer costs is defended on the ground that, since they vary directly with the area of the distribution system (or else with the lengths of the distribution lines, depending on the type of distribution system), they therefore vary directly with the number of customers. Alternatively, they are calculated by the "zero-intercept" method whereby regression equations are run relating cost to various sizes of equipment and eventually solving for the cost of a zero-sized system (Sterzinger, 1981).
>
> What this last-named cost imputation overlooks, of course, is the very weak correlation between the area (or the mileage) of a distribution system and the number of customers served by this system. For it makes no allowance for the density factor (customers per linear mile or per square mile). Our casual empiricism is supported by a more systematic regression analysis in (Lessels, 1980) where no statistical association was found between distribution costs and number of customers. Thus, if the company's entire service area stays fixed, an increase in number of customers does not necessarily betoken any increase whatever in the costs of a minimum-sized distribution system.[16]

Q. WHAT WAS DR. BONBRIGHT'S CONCLUSION REGARDING THE USE OF MSS AND ZERO-INTERCEPT STUDIES?

[16] James C. Bonbright, *et al*. Principles of Public Utility Rates. 1988 Edition. Arlington, VA: Public Utilities Reports, Inc., p. 491.

A. Dr. Bonbright found that attempts to classify costs associated with a minimum-sized distribution system, whether determined through the use of an MSS or a zero-intercept study, as something other than demand-related as potentially of merit. However, he ultimately concluded that classifying these costs as customer-related as the Company has done in the current proceeding is "clearly indefensible,"[17] due to the lack of a relationship between changes in the number of customers on a utility system and its distribution costs.

Table 3: Correlation of Customers and Distribution Network Additions

Year	Change in Average Number of Customers	Net Distribution Plant Addition	Poles, Towers, and Fixtures Additions	Overhead Conductors Additions	Underground Conduits Additions	Underground Conductors Additions	Line Transformers Additions
		($000)					
2008	36	$ 577	$ 322	$ 125	$ -	$ 58	$ 72
2009	79	463	295	75	(0)	52	40
2010	68	669	478	151	-	3	36
2011	25	684	374	190	-	41	79
2012	36	1,113	796	155	-	32	130
2013	38	773	510	119	-	45	100
2014	24	1,237	871	273	(4)	65	31
2015	21	853	691	91	-	24	46
2016	22	783	518	142	-	22	100
2017	13	1,122	670	239	-	132	81
2018	13	953	616	219	-	2	116
2019	9	1,132	775	296	-	30	30
2020	21	648	444	124	-	29	51
2021	24	1,897	1,309	451	-	31	106
2022	26	2,156	950	1,137	-	13	56
2023	28	2,103	1,102	731	-	52	218
2024	27	3,765	1,809	1,662	-	19	275
Correlation Coefficient		**-0.2473**	**-0.3077**	**-0.1677**	**0.0510**	**-0.1119**	**-0.1528**
P-Value		**0.3385**	**0.2296**	**0.5200**	**0.8457**	**0.6690**	**0.5583**
Significant at 95% Level		**Not Significant**	**Not Significant**	**Not Significant**	**Not Significant**	**Not Significant**	**Not Significant**

Source: Company's Annual Reports

Q. HAVE YOU QUANTITATIVELY ASSESSED THE HISTORIC CORRELATION BETWEEN INCREASES IN COMPANY DISTRIBUTION PLANT AND INCREASED NUMBER OF CUSTOMERS?

[17] *Id* at 492.

A. Yes. Table 3 examines trends between changes in average number of customers on the Company's system and distribution plant accounts 364-368 for the years 2008 through 2024. This analysis finds that additions to the relevant distribution plant accounts are not highly correlated with changes in the Company's average number of customers. Specifically, I estimate the correlation coefficient for the individual FERC accounts in question to range from negative 0.3077 to positive 0.0510, and I estimate the correlation coefficient of these distribution plant accounts in total to be negative 0.2499. Overall, this demonstrates very weak correlation as observed by Dr. Bonbright decades ago.

Q. HAVE OTHER JURISDICTIONS REJECTED THE USE OF AN MSS?

A. Yes. In 2021, the Michigan Public Service Commission rejected a proposal that Consumers Energy be required to submit an MSS in its next rate case.[18] Likewise, in 2010, the Rhode Island Public Utilities Commission rejected a request that it require the use of a minimum system study for Narragansett Electric Company D/B/A National Grid.[19]

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE RELIANCE ON AN MSS TO ALLOCATE COSTS ASSOCIATED WITH DISTRIBUTION PLANT ASSETS?

A. I recommend the Commission reject the Company's proposed MSS approaches in the classification of secondary-voltage distribution plant costs included in FERC Accounts 364-368. MSS and related zero-intercept approaches are fundamentally flawed and provide little to no value as to the just and reasonable setting of rates. Research has

[18] In the Matter of the Application of Consumers Energy Co. for Authority to Increase its Rates for the Generation and Distribution of Electricity and for Other Relief, Case No. U-20963, Order, dated December 22, 2021.

[19] In re: the Application of The Narragansett Elec. Co. D/B/A National Grid For Approval of A Change in Electric Base Distribution Rates, Docket No. 4065, Decision and Order, dated April 29, 2010.

shown these methods are flawed, and some state regulatory commissions have gone so far as to expressly reject their use. Further, while MSS is used by some utilities, it is not commonly used by all utilities. Thus, I recommend the Commission appropriately classify assets included in the relevant distribution plant accounts as 100 percent demand-related.

Q. DO YOU HAVE ANY OTHER QUALITATIVE COMMENTS ABOUT MR. GORMAN'S ANALYSIS TO CLASSIFY SECONDARY DISTRIBUTION PLANT BESIDES LINE TRANSFORMERS AS PARTIALLY CUSTOMER-RELATED?

A. Yes. As explained before, there is no direct relationship between the number of customers and the cost of these secondary distribution plant. For example, when a distribution line is upgraded, the costs of doing so are integrated and capitalized. If a new conductor is added, or new poles installed, there is no rationale to separating out the costs of labor, vehicle, and overhead as customer-related while only the costs of the materials of the poles and the conductor are related to demand. Without the poles and the conductor there would be no distribution line upgrade, and that upgrade was no doubt required because the expected future coincident demand to be imposed on those facilities required the upgrade, undermining the concept of attempting to identify a 'minimum' cost of interconnection since all of these costs are based on coincident demand considerations. Mr. Gorman's separation of these installation costs into customer- and demand-related is artificial and merely has the effect of shifting cost responsibility to low-load factor customer classes with numerous small customers.

Q. DO YOU HAVE ANY OTHER QUALITATIVE COMMENTS ABOUT MR. GORMAN'S ANALYSIS TO CLASSIFY LINE TRANSFORMERS AS PARTIALLY CUSTOMER-RELATED?

A. Yes. Similar to my observation concerning other secondary distribution network costs, upgrades to transformer capacity will depend upon the coincident demand that must be met by the local distribution systems. The reasons for making transformer investments is the need to meet these local coincident loads. Again, this undermines the concept of attempting to identify a 'minimum' cost since even this so-called minimum size transformer has significant load-carrying capability and its investment is made in recognition of these demand considerations and not simply to connect the customer to the system. For all these reasons, Mr. Gorman's classification of these costs should be rejected and 100 percent of these costs should be classified as demand-related.

D. Summary of ACOS Findings

Table 4: Summary of Results of Alternative ACOS

		Residential Service		Commercial and Industrial Service					Lighting Service		Exchange
	Total Citizens	Residential (RS)	All Electric (RSAE)	Non-Residential (NRS)	Non-Res. Heating (NRH)	Commercial (CS)	Comm. Heating (CSH)	Industrial (IS)	Municipal (MBL)	Outdoor (OL)	Service (EU)
Net Operating Income											
Total Operating Revenues	$ 6,729,636	$ 3,541,515	$ 26,642	$ 513,029	$ 806	$ 1,606,588	$ 1,293	$ 934,576	$ 13,737	$ 82,309	$ 9,141
Total Operating Expenses	6,554,566	3,725,736	35,645	502,267	2,311	1,490,367	4,737	759,001	8,316	19,145	7,041
Net Operating Income	**$ 175,070**	**$ (184,221)**	**$ (9,003)**	**$ 10,762**	**$ (1,505)**	**$ 116,221**	**$ (3,444)**	**$ 175,575**	**$ 5,421**	**$ 63,164**	**$ 2,100**
Total Rate Base	**$25,857,280**	**$12,911,025**	**$ 144,004**	**$ 1,527,665**	**$ 11,536**	**$ 7,448,726**	**$ 25,755**	**$3,491,929**	**$118,086**	**$157,891**	**$ 20,663**
Rate of Return on Rate Base	**0.68%**	**-1.43%**	**-6.25%**	**0.70%**	**-13.05%**	**1.56%**	**-13.37%**	**5.03%**	**4.59%**	**40.00%**	**10.16%**
Relative Rate of Return (RRO	**1.00**	**-2.11**	**-9.23**	**1.04**	**-19.27**	**2.30**	**-19.75**	**7.43**	**6.78**	**59.09**	**15.01**

Q. PLEASE SUMMARIZE YOUR ACOS FINDINGS.

A. Exhibit MWD-2 (Wellsboro), summarized in Table 4 above, presents the results of my alternative ACOS which appropriately classifies costs associated with secondary-voltage distribution plant accounts included in FERC Accounts 364-368 as 100 percent demand-related. My alternative ACOS show that the Company's incorrect classification of production plant and secondary-voltage distribution plant assets skews the allocation of costs and revenue responsibilities away from larger customers and onto residential customers. I recommend the Commission rely on the results of my alternative ACOS as

a fair and reasonable estimation of the relative costs of service between Company customer classes.

Table 5: Comparison of ACOS Results

	Total Citizens	Residential Service: Residential (RS)	Residential Service: All Electric (RSAE)	Commercial and Industrial Service: Non-Residential (NRS)	Commercial and Industrial Service: Non-Res. Heating (NRH)	Commercial and Industrial Service: Commercial (CS)	Commercial and Industrial Service: Comm. Heating (CSH)	Commercial and Industrial Service: Industrial (IS)	Lighting Service: Municipal (MBL)	Lighting Service: Outdoor (OL)	Exchange Service (EU)
Wellsboro's Proposed											
Rate of Return on Rate Base	0.68%	-2.38%	-5.94%	-1.79%	-13.34%	5.49%	-14.12%	5.03%	5.54%	47.33%	8.15%
Relative Rate of Return	1.00	-3.50	-8.74	-2.63	-19.62	8.07	-20.76	7.40	8.15	69.60	11.99
OCA Alterantive											
Rate of Return on Rate Base	0.68%	-1.43%	-6.25%	0.70%	-13.05%	1.56%	-13.37%	5.03%	4.59%	40.00%	10.16%
Relative Rate of Return	1.00	-2.10	-9.19	1.03	-19.19	2.29	-19.66	7.40	6.75	58.82	14.94

IV. REVENUE DISTRIBUTION

Q. PLEASE EXPLAIN THE PURPOSE OF THE REVENUE DISTRIBUTION PROCESS IN SETTING RATES.

A. The revenue distribution process allocates a utility's overall revenue deficiency across customer classes, which in turn, is used to establish a new set of retail rates. The revenue distribution process often uses the results from the ACOS as its starting point, but not necessarily as its ending point. Class-specific revenue responsibilities are established by allocating the system-wide revenue deficiency to classes that are under-earning, relative to their estimated ROR, and assigning, at least in theory, revenue decreases to those classes that are over-earning relative to their ACOS-estimated class returns. The final class revenue responsibilities are then used, in conjunction with each class's billing determinants, to determine rates. In summary, the revenue distribution process can be thought of as the initial step taken to establish rates.

Q. DOES THE REVENUE DISTRIBUTION PROCESS INCLUDE ANY POLICY CONSIDERATIONS?

A. Yes. Allocating the overall system-wide revenue deficiency entirely on a full cost of service basis can result in a very significant and adverse rate impact for under-earning

classes. Given this, regulators often determine the revenue responsibilities assigned to various customer classes by considering a set of generally accepted ratemaking principles.

Q. WHAT ARE THOSE GENERALLY ACCEPTED RATEMAKING PRINCIPLES?

A. There are several generally accepted rate-making principles used in utility regulation that include:

1) Rates should be fair, just, and reasonable, and not unduly discriminatory.

2) To the extent possible, gradualism should be used to protect customers from rate shock.

3) Rate continuity should be maintained.

4) Rates should be informed by costs, but class cost of service results need not be the only factor used in rate development.

5) Rates should be understandable to customers.

Q. HOW ARE THE ABOVE PRINCIPLES APPLIED IN DEVELOPING RATES FOR A REGULATED UTILITY?

A. It is important to consider all of the ratemaking principles I reference above. However, any principle's relative weight can change depending upon the importance of certain policy goals. Rate design should strike a balance between policy goals and resulting rates that are fair, just, and reasonable. There is no pre-set or universally accepted formula for developing rates or rate design, and, as a result, sound judgment is necessary to formulate a rate design that meets these objectives.

Table 6: Summary of Company's Proposed Revenue Allocation

		Residential Service		Commercial and Industrial Service					Lighting Service		Exchange
	Total Citizens	Residential (RS)	All Electric (RSAE)	Non-Residential (NRS)	Non-Res. Heating (NRH)	Commercial (CS)	Comm. Heating (CSH)	Industrial (IS)	Municipal (MBL)	Outdoor (OL)	Service (EU)
Allocated Cost of Service Results											
Rate of Return	0.68%	-2.38%	-5.94%	-1.79%	-13.34%	5.49%	-14.12%	5.03%	5.54%	47.33%	8.15%
Relative Rate of Return	1.00	-3.50	-8.74	-2.63	-19.62	8.07	-20.76	7.40	8.15	69.60	11.99
Proposed Revenue Allocation											
Current Distribution Revenues	$ 6,401,995	$3,370,741	$ 24,594	$ 498,637	$ 676	$ 1,522,475	$ 1,028	$ 880,020	$ 13,496	$ 81,371	$ 8,957
Proposed Distribution Revenues	2,899,388	1,668,860	14,885	236,093	507	601,598	771	354,548	6,155	12,757	3,214
Proposed Distribution Revenues	**$ 9,301,383**	**$5,039,601**	**$ 39,479**	**$ 734,730**	**$ 1,183**	**$ 2,124,073**	**$ 1,799**	**$1,234,568**	**$ 19,651**	**$ 94,128**	**$ 12,171**
Proposed Revenue Change	**45.29%**	**49.51%**	**60.52%**	**47.35%**	**75.00%**	**39.51%**	**75.00%**	**40.29%**	**45.61%**	**15.68%**	**35.88%**
Relative Proposed Revenue Increase	**1.00**	**1.09**	**1.34**	**1.05**	**1.66**	**0.87**	**1.66**	**0.89**	**1.01**	**0.35**	**0.79**

Q. PLEASE EXPLAIN THE COMPANY'S APPROACH TO REVENUE DISTRIBUTION.

A. The Company states that cost of service is just one consideration in developing its proposed revenue allocation. Specifically, while the Company proposes to move each class closer to cost of service, it does so with an objective of mitigating extreme rate impacts on rate classes and on customer subgroups.[20] Exhibit MWD-3 (Wellsboro), summarized in Table 6 above, presents the Company's estimated current class RROR and its proposed revenue distribution.

Q. WHAT DO YOU MEAN BY RROR?

A. The RROR effectively standardizes the class-specific ROR estimated by an ACOS to the overall system average. In other words, it divides the estimated class ROR by the estimated system ROR. For instance, assume that the residential class is earning a class-specific eight percent ROR, and further assume that the system-wide average ROR estimated by the same ACOS is also eight percent. The residential class, in this example, can be said to be earning a 1.0 RROR if the estimated ROR is the same as the overall system (*i.e.*, eight percent divided by eight percent equals 1.0). Put another way, any class earning a 1.0 RROR can be said to be making its full contribution to the system's overall ROR (*i.e.*, there is no cross-subsidy). A RROR that is greater than 1.0 indicates that a particular class is contributing more than the system average contribution to the Company's overall return. Likewise, a class that earns a RROR less than 1.0 but greater than zero can be said to be making a less-than-average contribution to the overall system.

[20] Direct Testimony of Howard S. Gorman at 28:15-18.

Q. DO YOU AGREE THAT A CLASS RROR LESS THAN 1.0 IS PROBLEMATIC OR INEQUITABLE?

A. Not necessarily. Consistent with the ratemaking principles identified above, there may be policy reasons to support a result that reflects a cross-subsidization. For example, the presence and/or continuation of a RROR below 1.0 could be the result of a prior agreed-upon rate freeze that prevents class rates from increasing to correct a revenue deficiency (relative to cost of service). In this example, the presence of a RROR below 1.0 is simply a function of a prior policy decision, not necessarily the result of some arbitrary or intentionally designed unreasonable inequity.

Q. WHAT ARE THE CLASS RATE INCREASES UNDER THE COMPANY'S PROPOSED REVENUE DISTRIBUTION?

A. The Company proposes to increase base rates by 45.3 percent on a system-wide average basis. Under the Company's proposal individual classes would receive increases ranging from a 15.7 percent increase for POL customers to as high as a 75.0 percent for non-residential heating ("NRH") and commercial service heating ("CSH) customers. This proposed increase to NRH and CSH customers is equal to nearly 1.66 times the overall system average increase of 45.3 percent. Likewise, the Company proposes to increase residential service-all electric ("RSAE") rates by 60.5 percent, which is nearly 1.34 times the overall system average increase of 45.3 percent.

Q. DO YOU AGREE WITH THE COMPANY'S PROPOSED REVENUE DISTRIBUTIONS?

A. No. The Company's proposed revenue distributions suffer from two deficiencies. First, the Company's proposal is based on the results of a faulty ACOS that overstates

the extent of any current subsidy from commercial and industrial customers to residential customers. Second, the Company's proposed increases to the NRH, CSH, and RSAE classes are inconsistent with the principles of gradualism.

Table 7: Summary of Alternative Proposed Revenue Allocation

	Total Citizens	Residential Service: Residential (RS)	Residential Service: All Electric (RSAE)	Commercial and Industrial Service: Non-Residential (NRS)	Commercial and Industrial Service: Non-Res. Heating (NRH)	Commercial and Industrial Service: Commercial (CS)	Commercial and Industrial Service: Comm. Heating (CSH)	Commercial and Industrial Service: Industrial (IS)	Lighting Service: Municipal (MBL)	Lighting Service: Outdoor (OL)	Exchange Service (EU)
Allocated Cost of Service Results											
Rate of Return	0.68%	-1.43%	-6.25%	0.70%	-13.05%	1.56%	-13.37%	5.03%	4.59%	40.00%	10.16%
Relative Rate of Return	1.00	-2.11	-9.23	1.04	-19.27	2.30	-19.75	7.43	6.78	59.09	15.01
Proposed Revenue Allocation											
Current Distribution Revenues	$ 6,401,995	$3,370,741	$ 24,594	$ 498,637	$ 676	$ 1,522,475	$ 1,028	$ 880,020	$ 13,496	$ 81,371	$ 8,957
Proposed Distribution Revenues	2,899,387	1,582,946	13,923	212,711	383	710,279	582	354,826	6,581	14,075	3,081
Proposed Distribution Revenues	**$ 9,301,382**	**$4,953,687**	**$ 38,517**	**$ 711,348**	**$ 1,059**	**$ 2,232,754**	**$ 1,610**	**$1,234,846**	**$ 20,077**	**$ 95,446**	**$ 12,038**
Proposed Revenue Change	**45.29%**	**46.96%**	**56.61%**	**42.66%**	**56.66%**	**46.65%**	**56.61%**	**40.32%**	**48.76%**	**17.30%**	**34.40%**
Relative Proposed Revenue Increase	**1.00**	**1.04**	**1.25**	**0.94**	**1.25**	**1.03**	**1.25**	**0.89**	**1.08**	**0.38**	**0.76**

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE COMPANY'S PROPOSED REVENUE DISTRIBUTION?

A. I recommend that the Commission adopt a more reasonable revenue distribution allocation method based on my alternative ACOS results that also limits the rate increase to the NRH, CSH, and RSAE customer classes to 1.25 times the overall system average increase. Under the Company's proposed overall distribution revenue increase of 45.3 percent this reduces the revenue increase to this rate class to 56.61 percent, compared to the Company's proposed distribution rate increases of 75.0 percent.

Table 8: Comparison of Class Revenue Allocations

	Total Citizens	Residential Service: Residential (RS)	Residential Service: All Electric (RSAE)	Commercial and Industrial Service: Non-Residential (NRS)	Commercial and Industrial Service: Non-Res. Heating (NRH)	Commercial and Industrial Service: Commercial (CS)	Commercial and Industrial Service: Comm. Heating (CSH)	Commercial and Industrial Service: Industrial (IS)	Lighting Service: Municipal (MBL)	Lighting Service: Outdoor (OL)	Exchange Service (EU)
Wellsboro's Proposed											
Distribution Revenue Increase	$ 2,899,388	$1,668,860	$ 14,885	$ 236,093	$ 507	$ 601,598	$ 771	$ 354,548	$ 6,155	$ 12,757	$ 3,214
Percentage Increase	45.29%	49.51%	60.52%	47.35%	75.00%	39.51%	75.00%	40.29%	45.60%	15.68%	36.89%
OCA Alterantive											
Distribution Revenue Increase	$ 2,899,387	$1,582,946	$ 13,923	$ 212,711	$ 383	$ 710,279	$ 582	$ 354,826	$ 6,581	$ 14,075	$ 3,081
Percentage Increase	45.29%	46.96%	56.61%	42.66%	56.61%	46.65%	56.61%	40.32%	48.76%	17.30%	34.40%

Q. HAVE YOU PREPARED A SUMMARY OF THE EFFECTS OF YOUR PROPOSED REVENUE DISTRIBUTION?

A. Yes. Exhibit MWD-4 (Wellsboro) presents an illustrative summary of the effects of my proposed revenue at the Company's proposed revenue requirement increase. My

proposed revenue distribution would increase base rates for the residential class by 46.88 percent, compared to the Company's proposal, which would increase such rates by 49.5 percent.

V. RATE DESIGN

Table 9: Summary of Company's Proposed Customer Charges

Rate Schedule	Current Charge	Proposed Charge	Percent Increase
Schedule RS - Residential Service	$12.00	$16.50	37.5%
Schedule RSAE - Residential Service All Electric	$12.00	$16.50	37.5%
Schedule NRS - Non-Residential Service	$12.22	$16.50	35.0%
Schedule NRH - Non-Residential Service Space Heating	$12.22	$16.50	35.0%
Schedule CS - Commercial Service	$32.03	$32.03	0.0%
Schedule CSH - Commercial Service Space Heaters	$45.81	$45.81	0.0%
Schedule IS - General Service	$85.00	$150.00	76.5%

Source: Company's Response to I&E-RE-1-D, Attachment A

Q. PLEASE DISCUSS THE COMPANY'S RESIDENTIAL CUSTOMER CHARGE PROPOSAL.

A. As summarized by Table 9, the Company is proposing to increase the monthly customer charges for nearly all rate classes. The Company is proposing to increase the fixed Residential Service ("RS") and RSAE customer charge from $12.00 to $16.50 per month, representing a 37.5 percent increase.[21] Likewise, the Company is proposing to increase its Non-Residential Service ("NRS") and NRH customer charge from $12.22 to $16.50 per month, representing a 35 percent increase.[22]

[21] Direct Testimony of Howard Gorman, Exhibit HSG-1, Schedule B7.

[22] *Id.*

Table 10: Survey of Regional Customer Charges

Company	State	Residential Customer Charge ($/month)	Commercial Customer Charge ($/month)
Wellsboro Electric Company (Current)	**PA**	**$ 12.00**	**$ 12.22**
Wellsboro Electric Company (Proposed)	**PA**	**$ 16.50**	**$ 16.50**
Black Diamond Power Company	WV	8.00	10.12
Citizens' Electric Company	PA	13.10	16.00
Kentucky Utilities Company	VA	12.00	30.00
Pennsylvania Electric Company	NY	8.50	10.50
Pike County Light & Power Company	PA	8.80	17.26
Rockland Electric Company	NJ	5.75	16.00
The Toledo Edison Company	OH	4.00	7.00
UGI Utilities, Inc.	PA	10.75	17.00
Wheeling Power Company	WV	12.50	15.00
Peer Group Average		**$ 9.27**	**$ 15.43**

Source: Utility Tariffs

Q. HAVE YOU COMPARED THE COMPANY'S PROPOSED RESIDENTIAL CUSTOMER CHARGES TO OTHER REGIONAL ELECTRIC UTILITIES?

A. Yes, and this analysis is presented in Table 10, which surveys current residential and small commercial customer charges among other regional electric utility companies. There are only two (out of nine) electric utilities in the survey with residential customer charges greater than the Company's $12.00 per month. The average across all regional peers is $9.27, which is lower than the Company's current rate and significantly lower than the proposed customer charge of $16.50 per month. Indeed, the proposed customer charge of $16.50 per month is the highest in the region. Likewise, the Company's proposed increase in NRS and NRH customer charge to $16.50 per month would be higher than the regional average of $15.43 per month.

Q. WHAT IS THE BASIS OF THE COMPANY'S PROPOSED CUSTOMER CHARGE INCREASE?

A. The Company claims that its ACOS supports a $46.95 monthly residential customer charge based on cost of service.[23] Likewise, the Company provides information supporting a claim that its ACOS supports a $46.80 monthly NRS customer charge based on cost of service.[24]

Q. DO YOU AGREE WITH THE MANNER IN WHICH THE COMPANY MADE THESE CALCULATIONS?

A. No. The Company's analysis significantly overstates the cost directly attributable to residential customers. Specifically, it includes secondary distribution costs as customer-related based on its flawed zero-load analysis and minimum size analysis allocations, as discussed earlier.

Table 11: Analysis of Company Customer-Related Costs

Line No.	Description	Residential Service: Residential All Electric (RS)	Residential Service: (RSAE)	Commercial and Industrial Service: Non-Residential (NRS)	Non-Res. Heating (NRH)	Commercial (CS)	Comm. Heating (CSH)	Industrial (IS)
1	Customer-Related Costs per Company's ACOS							
2	Class Functionalized Customer Billing Expenses	$ 995,243	$ 5,626	$ 180,980	$ 193	$ 105,889	$ 270	$ 9,716
3	Number of Bills	61,910	350	11,258	12	4,704	12	160
4	**Monthly Customer-Related Costs/Customer**	**$ 16.08**	**$ 16.08**	**$ 16.08**	**$ 16.08**	**$ 22.51**	**$ 22.51**	**$ 60.73**
5	Customer Charge Revenue at Current Rates							
6	Customer Charge Revenue at Current Rates	$ 741,480	$ 4,200	$ 136,106	$ 147	$ 149,132	$ 550	$ 13,600
7	Number of Bills	61,910	350	11,258	12	4,704	12	160
8	**Monthly Customer Charge Revenue/Customer**	**$ 11.98**	**$ 12.00**	**$ 12.09**	**$ 12.25**	**$ 31.70**	**$ 45.83**	**$ 85.00**
9	**Relationship of Customer Charge Revenues to Customer-Related Costs**	**74.50%**	**74.65%**	**75.20%**	**76.20%**	**140.84%**	**203.61%**	**139.97%**

Source: Company's Response to OCA-I-1, Attachment A (Schedule E)

Q. HAVE YOU PREPARE AN ANALYSIS OF COSTS COMMONLY ASSOCIATED WITH CUSTOMER CHARGES?

A. Yes. That analysis is provided in Table 11. "Customer-related" expense accounts are those typically allocated on the basis of customers and can include: removing and

[23] Direct Testimony of Howard Gorman, Exhibit HSG-1, Schedule E-1B.

[24] *Id.*

setting meters; maintenance of meters; services expense; maintenance of service drops; meter reading expense; dispatch applications and orders; customer records and collections; customer billing and accounting; customer service and information; and sales expense. These costs can also include the depreciation expense associated with the service drop and meter plant accounts and property taxes, as well as the carrying charges (at the Company's requested rate of return) for the customer portion of services investment and 100 percent of the meters investment.

Q. HOW DO THE COMPANY'S CUSTOMER CHARGE REVENUES COMPARE WITH THE RESULTS OF YOUR ANALYSIS?

A. The Company's current customer charge revenue associated with the residential class is 74.5 percent of the class' customer-related cost responsibilities. Likewise, the Company's current customer charge revenue associated with the NRS class is 75.2 percent of the class' customer-related cost responsibilities.

Q. DO THESE RESULTS INDICATE ANY PRESSING NEED TO INCREASE MONTHLY CUSTOMER CHARGE RATES?

A. No. All Company residential and commercial service rate classes currently cover the majority of their customer-related costs through monthly customer charges. The lowest, the residential class, still recovers 74.5 percent of its customer-related costs through its monthly customer charge.

Q. IS THE COMPANY'S PROPOSAL TO INCREASE THE CUSTOMER CHARGE CONSISTENT WITH PROMOTING ENERGY EFFICIENCY AND CONSERVATION?

A. No. The Company's rate design proposal is inconsistent with energy efficiency, since it reduces economic incentives for ratepayers to control their monthly utility bills

through energy efficiency and conservation efforts, because only the variable component of bills is avoidable.

Q. HAVE OTHER REGULATORS RECOGNIZED THE NEGATIVE IMPACTS THAT CUSTOMER CHARGE INCREASES CAN HAVE FOR ENERGY EFFICIENCY?

A. Yes. In rejecting a request by Baltimore Gas and Electric ("BGE") to increase customer charges as part of a larger rate design proposal, the Maryland Public Service Commission ("MPSC") recognized the need to allow customers the opportunity to control their monthly bills by reducing energy usage.

> Even though this issue was virtually uncontested by the parties, we find we must reject Staff's proposal to increase the fixed customer charge from $7.50 to $8.36. Based on the reasoning that ratepayers should be offered the opportunity to control their monthly bills to some degree by controlling their energy usage, we instead adopt the Company's proposal to achieve the entire revenue requirement increase through volumetric and demand charges. This approach also is consistent with and supports our EmPOWER Maryland goals.[25]

Q. CAN YOU POINT TO ANY OTHER REGULATORY EXAMPLES?

A. Yes. The Montana Public Service Commission ("MT PSC") addressed this issue in evaluating, and rejecting, a proposal by Energy West Montana to eliminate volumetric charges and only have one fixed monthly customer charge (known as a "straight-fixed variable" or "SFV" rate design):

> The Commission agrees that most distribution costs are not avoidable, and that volumetric distribution charges may encourage conservation actions that, all other things being

[25] Maryland Public Service Commission Case No. 9299, In the Matter of the Application of Baltimore Gas and Electric Company for Adjustment in its Electric and Gas Base Rates (*"Case No. 9299"*). Order No. 85374 at p. 99, rel. February 22, 2013.

> equal, reduce the utility's embedded cost recovery between rate cases and contribute to future rate increases.
>
> …
>
> The Commission agrees that an SFV rate design is a clean and administratively inexpensive way to decouple revenue from volume. An often-cited public policy justification for revenue decoupling is to remove the volume disincentive for cost-effective conservation investment by a gas distribution company, which through SFV and other decoupling methods is rendered indifferent to the volume of gas consumed. Yet, SFV rates decouple revenue at the cost of decreasing returns to conservation investment by customers. For this reason the net conservation benefit of revenue decoupling via SFV rates is not clear, and may be negative.[26]

Q. HAVE ANY REGULATORY RESEARCH INSTITUTES ADDRESSED THE ISSUE OF THE RELATIONSHIP BETWEEN HIGH CUSTOMER CHARGES AND ENERGY EFFICIENCY?

A. Yes. A research document presented for consideration by the membership of NARUC notes that extreme increases in customer charges, that typically happen under SFV rate design proposals, are problematic because of its effects on customer incentives to conserve energy:

> **Straight-Fixed Variable Rate Design.** This mechanism eliminates all variable distribution charges and costs are recovered through a fixed delivery services charge or an increase in the fixed customer charge alone. With this approach, it is assumed that a utility's revenues would be unaffected by changes in sales levels if all its overhead or fixed costs are recovered in the fixed portion of customers' bills. <u>This approach has been criticized for having the unintended effect of reducing customers' incentive to use less</u>

[26] In The Matter Of Energy West Montana, Application To Establish Increased Service Rates In Its Great Falls, Cascade, And West Yellowstone Service Areas, Montana Public Service Commission, Docket No. D2010.9.90, Order No, 7132c, at 29–30, rel. November 17, 2011.

> electricity or gas by eliminating their volumetric charges and billing a fixed monthly rate, regardless of how much customers consume.[27]

Q. HAS ANY NATIONAL PUBLIC POLICY ANALYSIS NOTED THE EFFICIENCY DISINCENTIVES ASSOCIATED WITH HIGH CUSTOMER CHARGES?

A. Yes. The National Action Plan for Energy Efficiency ("NAPEE"), a joint venture of the U.S. Department of Energy and U.S. Environmental Protection Agency, published a whitepaper on various rate design effects on encouraging energy efficient behaviors. The NAPEE postulated that rate designs over-emphasizing customer charges, like SFV, can deter or weaken the economic signals sent to customers to change their energy usage behavior and make investments in energy efficiency devices:

> Because [SFV] tends to shift costs out of volumetric charges, it tends to reduce customers' efficiency incentive, because the marginal price of additional consumption is reduced. While SFV rates are being considered to better reflect the utility's costs behind the rate, these rates do not encourage customers to change energy usage behavior or invest in efficiency technologies. Such customer disincentives persist even when SFV rates are applied to individual components of the bill, such as charges for distribution service.[28]

Q. SHOULD THE COMMISSION BE MINDFUL OF THE EFFECT OF THE COMPANY'S PROPOSED RATE DESIGN ON LOW-USE RESIDENTIAL CUSTOMERS?

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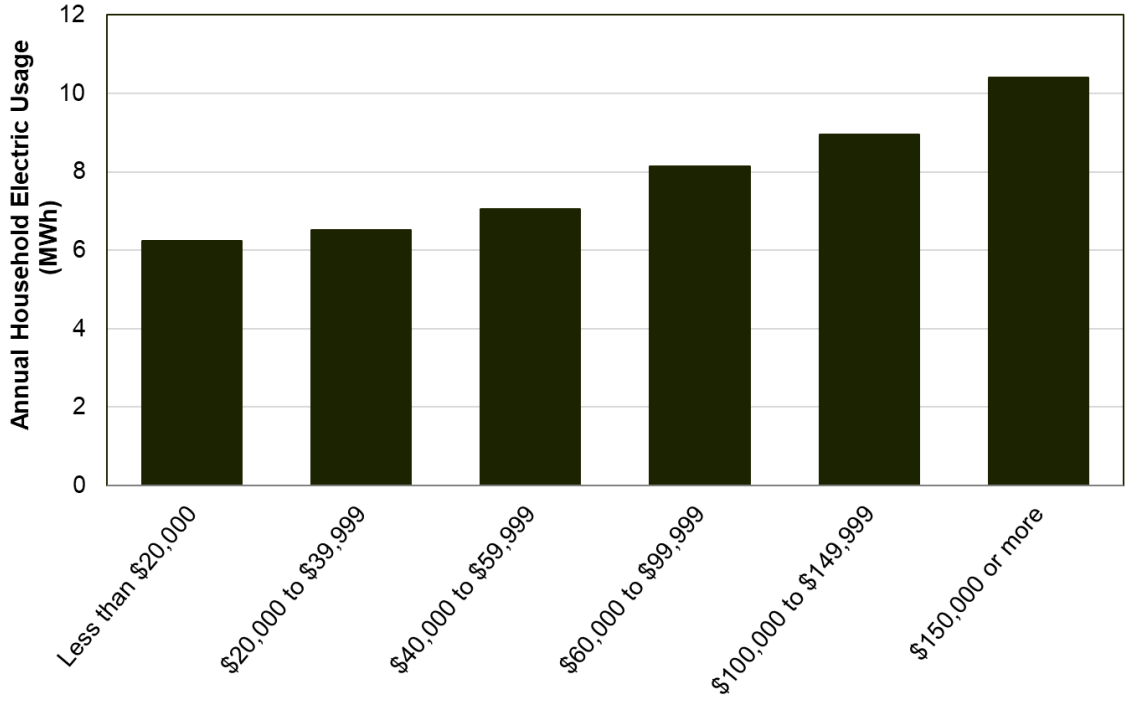
[27] "Decoupling for Electric & Gas Utilities: Frequently Asked Questions (FAQ)" Grants & Research Department, National Association of Regulatory Utility Commissioners, at 5 (Sept. 2007) (emphasis added).
[28] Customer Incentives for Energy Efficiency Through Electric and Natural Gas Rate Design, National Action Plan for Energy Efficiency at 13-14, prepared by William Prindle, ICF International, Inc. (Sept. 2009) (emphasis added).

A. Yes. There are numerous studies in the academic literature supporting the hypothesis that electricity is a "normal good."[29] That is, the consumption of electricity is directly correlated with household income level, meaning that higher-use electrical customers are typically higher income individuals and lower-use electrical customers are typically lower income individuals. These are important factual considerations the Commission should bear in mind.

Figure 1: Analysis of Electricity Usage and Household Income



Source: EIA 2020 Residential Energy Consumption Survey

[29] *See*, Alberini, A., W. Gans, D. Velez-Lopez. 2011, "Residential consumption of gas and electricity in the U.S.: The role of prices and income," Energy Economics 33, 870-881; Bernard, J., D. Bolduc, N. Yameogo, 2011, "A pseudo-panel data model of household electricity demand," Resource and Energy Economics 33(1), 315-325; Dax, P. 1987, "Estimation of Income Elasticity from Cross-Section Data," Applied Economics 19 (11), 1471-1482; Fell, H., S. Li, A. Paul. 2010, "A New Look at Residential Electricity Demand Using Household Expenditure Data," RFF DP 10-57; Fullerton, T. D. Juarez, A. Walke. 2012, "Residential Electricity Consumption in Seattle," Energy Economics; Reiss. P.C., and M. W. White, 2005, "Household electricity demand revisited," Review of Economic Studies 72, 853-858; and Swan L.G., V. I. Ugursan, 2009, "Modeling of end-use energy consumption in the residential sector: A review of modeling techniques," Renewable and Sustainable Energy Reviews 13, 1819-1835.

Q. HAVE YOU CONDUCTED ANY ANALYSES EXAMINING THE RELATIONSHIP OF ELECTRICITY USAGE AND INCOME?

A. Yes. Figure 1 provides the results of an analysis I have performed using data from the 2020 Residential Electricity Consumption Survey ("RECS") produced by the United States Energy Information Administration ("EIA") and household data from the Census division in which the Pennsylvania is located.[30] The results show a positive relationship between electricity consumption (in kWh terms) and income. This clearly shows that as income increases, electricity consumption increases, and vice versa: as income decreases, electricity usage decreases.

Q. WHAT ARE YOUR CUSTOMER CHARGE RECOMMENDATIONS AND CONCLUSIONS?

A. I recommend that the Commission reject Wellsboro's proposed increase in residential customer charges. First, the Company's proposal is based upon an inaccurate accounting of customer-related costs. A correct analysis of customer-related costs from Wellsboro's ACOS finds that all residential and commercial rate classes are currently recovering *nearly all* customer-related costs through monthly customer charges. Second, Wellsboro's existing residential customer charge is third highest and the proposed increase would make the charge the highest among regional peer investor-owned utilities. Third, the proposal would negatively impact the public policy goals of energy efficiency and would burden low-use customers with a greater than average portion of any proposed

[30] This census division also includes the states of Connecticut, Maine, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island, and Vermont. This is the most detailed level of aggregation available in the RECS.

increase in the case. The Commission should keep Wellsboro's current customer charges for all customers.

Q. DO YOU HAVE AN ALTERNATIVE RECOMMENDATION IF THE COMMISSION DECIDES AN INCREASE IN MONTHLY CUSTOMER CHARGES IS WARRANTED?

A. Yes. I recommend that the Commission limit its increase in Wellsboro monthly customer charges to only that required to bring the Company's customer charges in line with Citizens' Electric Company. This would increase the residential customer charge to $13.10 per month.

VI. CONCLUSIONS AND RECOMMENDATIONS

Q. WHAT ARE YOUR ACOS FINDINGS FOR WELLSBORO?

A. My alternative ACOS analyses shows that Wellsboro's incorrect classification of secondary-voltage distribution plant skews the allocation of costs and revenue responsibilities away from larger customers and onto residential customers. I recommend the Commission rely on the results of my alternative ACOS as a fair and reasonable estimation of relative costs of service between Wellsboro's customer classes.

Q. WHAT IS YOUR RECOMMENDATION REGARDING WELLSBORO'S PROPOSED REVENUE DISTRIBUTION?

A. For Wellsboro, I recommend that the Commission adopt a more reasonable revenue distribution allocation method based on my alternative ACOS results that also limits the rate increase to the to the NRH, CSH, and RSAE customer classes to 1.25 times the overall system average increase. Under Wellsboro's proposed overall distribution revenue increase of 45.3 percent this reduces the revenue increase to these rate classes

to 56.61 percent, compared to the Company's proposed distribution rate increases of 75.0 percent for the NRH and CSH classes, and 60.52 percent for the RSAE class.

Q. WHAT IS YOUR RECOMMENDATION REGARDING WELLSBORO'S PROPOSED RATE DESIGN FOR CUSTOMER CHARGES?

A. I recommend the Commission reject Wellsboro's proposed increases in customer charges because they disproportionately impact low-income customers and reduce customer incentives to reduce usage, contrary to public goals of promoting energy efficiency. Furthermore, Wellsboro's existing residential customer charge is third highest and the proposed increase would make the charge the highest among regional peer investor-owned utilities. Finally, a correct analysis of customer-related costs from Wellsboro's ACOS finds that all residential and commercial rate classes are currently recovering *nearly all* customer-related costs through monthly customer charges.

Q. DO YOU HAVE AN ALTERNATIVE RECOMMENDATION IF THE COMMISSION DECIDES AN INCREASE IN MONTHLY CUSTOMER CHARGES IS WARRANTED?

A. Yes. I recommend that the Commission limit its increase in Wellsboro monthly customer charges to only that required to bring the Company's customer charges in line with Citizens' Electric Company. This would increase the residential customer charge to $13.10 per month.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

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EDUCATION

M.A. in Economics, Kansas University, 2009

B.A. in Business Economics, Buena Vista University, 2007

PROFESSIONAL EXPERIENCE

Acadian Consulting Group, Baton Rouge, Louisiana

Spring 2025 – Present	Senior Research Consultant
Summer 2021 – Spring 2025	Research Consultant
Summer 2016 – Summer 2021	Research Associate
Winter 2011 – Summer 2016	Senior Research Analyst

Kansas Corporation Commission, Topeka, Kansas

Utilities Division

Summer 2011 – Winter 2011	Senior Research Economist

Research Division

Spring 2009 – Summer 2011	Research Analyst

Kansas Energy Council

Summer 2008 – Spring 2009	Research Assistant

PUBLICATIONS AND REPORTS

1. The challenges of the regulatory review of diversification mergers. With Dr. David E. Dismukes. *The Electricity Journal* 29 (2016) 8-14. (May 2016)

PROFESSIONAL AND CIVIC PRESENTATIONS

1. "Natural Gas Distribution" (2025). Prepared for the Louisiana State University, Center for Energy Studies, Energy Fundamentals 2025. June 24 and July 8, 2025.

2. "Development Trends, Issues, and Challenges with Clean Hydrogen Production" (2025). Prepared for the Michigan State University, Institute of Public Utilities, Annual Regulatory Studies Program. April 15, 2025.

3. "Status and Future of Natural Gas Supply and Infrastructure" (2025). Prepared for the Michigan State University, Institute of Public Utilities, Annual Regulatory Studies Program. April 8, 2025.

4. "Observed Impact of Formula Rate Plans Across the United States" (2024). Prepared for Arizona Corporation Commission Formula Rate Plan Workshop. October 3, 2024.

EXPERT WITNESS, LEGISLATIVE, AND PUBLIC TESTIMONY; EXPERT REPORTS, RECOMMENDATIONS, AND AFFIDAVITS

1. Expert Testimony. Cause No. 46120. (2025). Before the Indiana Utility Regulatory Commission. *Verified Petition of NIPSCO Generation LLC for Certain Determinations by the Commission with Respect to its Jurisdiction Over Petitioner's Activities as a Non-Retail Generator of Electric Power.* On Behalf of the Indiana Office of Utility Consumer Counselor. Issues: Rate Design, Large Data Center Loads.

2. Expert Testimony. Case No. U-21859. (2025). Before the Michigan Public Service Commission. *In the matter of the application of Consumers Energy Company for Ex Parte Approval of Certain Amendments to Rate GPD.* On Behalf of the Michigan Attorney General. Issues: Rate Design, Large Data Center Loads.

3. Expert Testimony. Docket No. R-2025-3053112. (2025). Before the Pennsylvania Public Utilities Commission. *Pennsylvania Public Utility Commission v. Philadelphia Gas Works.* On Behalf of the Pennsylvania Office of Consumer Advocate. Issues: Decoupling, Regulatory Lag.

4. Expert Testimony. Docket No. E-01773A-24-0220. (2025). Before the Arizona Corporation Commission. *In the Matter of the Application of Arizona Electric Power Cooperative, In. for a Hearing to Determine the Fair Value of its Property for Ratemaking Purposes, to Fix a Just and Reasonable Return Thereon and To Approve Rates Designed to Develop Such Return.* On Behalf of Arizona Corporation Commission Staff. Issues: Cost of Service, Qualifying Facilities.

5. Expert Testimony. Case No. U-21816. (2025). Before the Michigan Public Service Commission. *In the matter of Consumer Energy Company's application for the regulatory reviews, revisions, determinations, and/or approvals necessary to fully comply with Public Act 295 of 2008, as amended by Public Act 235 of 2023.* On Behalf of the Attorney General. Issues: Capital Expense, Cost Recovery

6. Expert Testimony. Cause No. 46120. (2024). Before the Indiana Utility Regulatory Commission. *Petition of Northern Indiana Public Service Company LLC Pursuant to Ind. Code §§ 8-1-2-42.4, 8-1-2-61 and 8-1-2.5-6 for (1) Authority to Modify its Retail Rates and Charges for Electric Utility Service Through a Phase in of Rates;*

(2) Approval of New Schedules of Rates and Charges, General Rules and Regulations, and Riders (both Existing and New); (3) Approval of Revised Common and Electric Depreciation Rates Applicable to its Electric Plant in Service; (4) Approval of Necessary and Appropriate Accounting Relief, Including, but Limited to, Authority to Capitalize as Rate Base All Expenditures for Improvements to Petitioner's Information Technology Systems through the Design, Development, and Implementation of a Work and Asset Management ("WAM") Program, to the Extent Necessary; and (5) Approval of Alternative Regulatory Plans for the Partial Waiver of 170 IAC 4-1-16(f) and Proposed Remote Disconnection and Reconnection Process and, to the Extent Necessary, Implementation of a Low Income Program. On Behalf of the Indiana Office of Utility Consumer Counselor. Issues: Cost of Service, Rate Design.

7. Expert Testimony. Cause No. 46097. (2024). Before the Indiana Utility Regulatory Commission. *In the Matter of the Verified Petition of Indiana Michigan Power Company for Approval of Modifications to its Industrial Power Tariff – Tariff I.P.* On Behalf of the Indiana Office of Utility Consumer Counselor. Issues: Rate Design, Large Data Center Loads.

8. Expert Report. Docket No. AHD-00000J-23-0273. (2024). Before the Arizona Corporation Commission. *In the Matter of the Application of the Arizona Corporation Commission's Exploration of Changes to the Up to 10% Annual Reduction in the Export Rate and the 10-Year Export Rate Effective Period Under the Resource Comparison Proxy Methodology Approved in the Value and Cost of Distributed Generation Docket (E-00000J-14-0023).* On Behalf of the Arizona Corporation Commission Staff. Issues: Value of Solar.

9. Expert Testimony. Case No. U-21585. (2024). Before the Michigan Public Service Commission. *In the Matter of the Application of Consumers Energy Company for Authority to Increase its Rates for the Generation and Distribution of Electricity and Other Relief.* On Behalf of the Attorney General. Issues: Capital Expenses.

10. Expert Report. *Review of LPSC Rules Regarding Distributed Generation: Report on Phase II of Rule-Making.* Docket No. R-33929. (2019). *In Re: Review of Policies Related to Customer-owned Solar Generation and Possible Modification of the Commission's Current Net Metering Rules.* On behalf of Louisiana Public Service Commission. Issues: Solar Net Metering.

11. Expert Report. (2011). *2011 Kansas Generation Planning Survey*. On behalf of the Kansas Corporation Commission Staff.

12. Expert Testimony. Docket No. 11-KCPE-581-PRE. (2011). Before the Kansas Corporation Commission. *In the Matter of the Petition of Kansas City Power & Light Company ("KCP&L") for Determination of the Ratemaking Principles and Treatment That Will Apply to the Recovery in Rates of the Costs to be Incurred by KCP&L for Certain Electric Generation Facilities Under K.S.A. 66-1239.* On Behalf

of the Kansas Corporation Commission Staff. Issues: System Planning, Predetermination.

13. Expert Testimony. Docket No. 10-KCPE-795-TAR. (2010). Before the Kansas Corporation Commission. *In the Matter of the Application of Kansas City Power & Light Company for Approval to Implement a Portfolio of Demand Side Management Programs Including Affordability, Energy Efficiency, Demand Response and Educational Programs, and to Implement a Rider for Recovery of Program Costs and Incentives Associated with this Portfolio.* On Behalf of the Kansas Corporation Commission Staff. Issues: Demand Side Management, Cost-Benefit Analyses.

14. Expert Testimony. Docket No. 10-WSEE-775-TAR. (2010). Before the Kansas Corporation Commission. *In the Matter of the Application of Westar Energy, Inc. and Kansas Gas and Electric Company for an Order Authorizing them to participate in Efficiency Kansas, Approve the SimpleSavings Program Rider, and related cost recovery.* On Behalf of the Kansas Corporation Commission Staff. Issues: Demand Side Management, Cost-Benefit Analyses.

15. Expert Testimony. Docket No. 10-BHCG-639-TAR. (2010). Before the Kansas Corporation Commission. *In the Matter of the Application of Black Hills/Kansas Gas Utility Company, LLC, d/b/a Black Hills Energy for Approval to Implement Black Hills Energy's Five-Year Energy Efficiency Plan Consisting of Natural Gas Energy Efficiency Programs to Improve Building and Equipment Efficiency and to Educate About Efficient Energy Usage, to Provide for Program Cost Recovery Through a Rider Mechanism, Permit the Implementation of a Revenue Normalization Mechanism to Replace the Weather Normalization Adjustment, a Performance Incentive Mechanism, and Appropriate Accounting Authority to Defer Expenses and Revenues Associated with the Filing.* On Behalf of the Kansas Corporation Commission Staff. Issues: Demand Side Management, Cost-Benefit Analyses.

16. Expert Testimony. Docket No. 10-EPDE-497-TAR. (2010). Before the Kansas Corporation Commission. *In the Matter of the Application of the Empire District Electric Company for Approval to Implement its Portfolio of Energy Efficiency and Demand Response Programs for its Kansas Customers, to Provide for Program Cost Recovery and Lost Revenue Through a Rider Mechanism, to Obtain any Necessary Waivers for the Commission, and for Appropriate Accounting Authority to Defer Expenses and Revenues Associated with the Filing.* On Behalf of the Kansas Corporation Commission Staff. Issues: Demand Side Management, Cost-Benefit Analyses.

17. Expert Testimony. Docket No. 10-KGSG-421-TAR. (2010). Before the Kansas Corporation Commission. *In the Matter of the Application of Kansas Gas Service, a Division of ONEOK, Inc., for Approval to Implement the Efficiency Kansas Energy Efficiency Program, to Implement Natural Gas Energy Efficiency Programs to Improve Building and Equipment Efficiency and to Educate about Efficient Energy*

Usage, To Provide for Program Cost Recovery Through a Rider Mechanism, to Establish Administrative Charges and a Program Initiation Fee, Permit the Implementation of a Revenue Decoupling Mechanism, and Appropriate Accounting Authority to Defer Expenses and Revenues Associated with the Filing. On Behalf of the Kansas Corporation Commission Staff. Issues: Demand Side Management, Cost-Benefit Analyses.

Table of Exhibits

Title	Exhibit
Summary of Results of Company's Proposed ACOS	Exhibit MWD-1
Summary of Results of Alternative ACOS	Exhibit MWD-2
Summary of Company's Proposed Revenue Allocation	Exhibit MWD-3
Summary of Results of Alternative Revenue Allocation	Exhibit MWD-4

Summary of Results of Company's Proposed ACOS: Relative Rate of Return at Current Rates

Line No.	Account Description	Total Wellsboro	Residential Service: Residential (RS)	Residential Service: All Electric (RSAE)	Commercial and Industrial Service: Non-Residential (NRS)	Commercial and Industrial Service: Non-Res. Heating (NRH)	Commercial and Industrial Service: Commercial (CS)	Commercial and Industrial Service: Comm. Heating (CSH)	Commercial and Industrial Service: Industrial (IS)	Lighting Service: Municipal (MSL)	Lighting Service: Outdoor (POL)	Exchange Service (EU)
1	**Rate Base**											
2	Total Utility Plant	$ 44,666,856	$24,683,945	$ 247,029	$ 3,236,711	$ 16,285	$10,067,760	$ 33,500	$6,105,310	$ 91,302	$ 139,363	$ 45,651
3	Total Depreciation Reserve	(19,321,064)	(10,673,222)	(106,361)	(1,404,820)	(7,060)	(4,447,890)	(14,763)	(2,661,718)	19,774	(1,231)	(23,773)
4	Total Other Rate Base Items	511,488	319,681	2,943	51,929	190	86,596	402	48,346	641	34	729
5	**Total Rate Base**	**$ 25,857,280**	**$14,330,403**	**$ 143,611**	**$ 1,883,819**	**$ 9,415**	**$ 5,706,466**	**$ 19,138**	**$3,491,939**	**$ 111,717**	**$ 138,165**	**$ 22,606**
6	**Operating Income**											
7	**Operating Revenue**											
8	Distribution Revenues	$ 6,401,996	$ 3,370,741	$ 24,594	$ 498,637	$ 676	$ 1,522,475	$ 1,028	$ 880,020	$ 13,496	$ 81,371	$ 8,957
9	Forfeited Discounts	31,122	27,073	199	516	1	2,076	1	1,189	-	55	12
10	Rent for Electric Property	273,619	137,412	1,663	14,663	114	68,475	231	50,219	168	516	158
11	Other Operating Revenues	22,899	12,057	88	1,784	2	5,446	4	3,148	48	291	32
12	**Total Operating Revenues**	**$ 6,729,636**	**$ 3,547,282**	**$ 26,544**	**$ 515,600**	**$ 794**	**$ 1,598,472**	**$ 1,264**	**$ 934,576**	**$ 13,712**	**$ 82,233**	**$ 9,159**
13	**Operating Expenses**											
14	Distribution and Transmission Expenses	$ 1,602,629	$ 816,430	$ 9,710	$ 89,126	$ 663	$ 405,012	$ 1,361	$ 273,196	$ 1,805	$ 3,823	$ 1,502
15	Customer Account and Service Expenses	1,093,791	861,654	4,901	153,855	165	68,328	172	3,773	-	35	910
16	Administration and General Expenses	1,636,599	981,092	8,880	139,624	530	314,588	1,028	182,805	2,388	3,761	1,905
17	Depreciation Expense	1,939,404	1,083,370	10,658	144,200	688	428,719	1,416	260,334	2,732	4,716	2,569
18	General Taxes	44,148	24,330	244	3,179	16	9,998	33	6,073	91	139	45
19	Gross Receipts Tax	377,718	198,874	1,451	29,420	40	89,826	61	51,921	796	4,801	528
20	Income Taxes	(139,723)	(77,214)	(773)	(10,125)	(51)	(31,493)	(105)	(19,098)	(286)	(436)	(143)
21	**Total Operating Expenses**	**$ 6,554,565**	**$ 3,888,535**	**$ 35,071**	**$ 549,279**	**$ 2,051**	**$ 1,284,977**	**$ 3,966**	**$ 759,003**	**$ 7,527**	**$ 16,840**	**$ 7,317**
22	**Net Operating Income**	**$ 175,071**	**$ (341,253)**	**$ (8,527)**	**$ (33,679)**	**$ (1,256)**	**$ 313,495**	**$ (2,702)**	**$ 175,573**	**$ 6,186**	**$ 65,393**	**$ 1,842**
23	**Rate of Return on Rate Base ("ROR")**	**0.68%**	**-2.38%**	**-5.94%**	**-1.79%**	**-13.34%**	**5.49%**	**-14.12%**	**5.03%**	**5.54%**	**47.33%**	**8.15%**
24	**Relative Rate of Return ("RROR")**	**1.00**	**(3.52)**	**(8.77)**	**(2.64)**	**(19.71)**	**8.11**	**(20.85)**	**7.43**	**8.18**	**69.90**	**12.03**

Source: Company's Response to OCA-I-1, Attachment A (Schedule E).

Summary of Results of Company's Proposed ACOS: Required Increase at Equalized Rates

Line No.	Account Description	Total Wellsboro	Residential Service: Residential (RS)	Residential Service: All Electric (RSAE)	Commercial and Industrial Service: Non-Residential (NRS)	Commercial and Industrial Service: Non-Res. Heating (NRH)	Commercial and Industrial Service: Commercial (CS)	Commercial and Industrial Service: Comm. Heating (CSH)	Commercial and Industrial Service: Industrial (IS)	Lighting Service: Municipal (MSL)	Lighting Service: Outdoor (POL)	Exchange Service (EU)
1	**Revenue Requirement**											
2	**Required Income Under Company's Proposed ROR**											
3	Total Rate Base	$25,857,280	$14,330,403	$ 143,611	$ 1,883,819	$ 9,415	$ 5,706,466	$ 19,138	$3,491,939	$ 111,717	$ 138,165	$ 22,606
4	Proposed Rate of Return	8.18%	8.18%	8.18%	8.18%	8.18%	8.18%	8.18%	8.18%	8.18%	8.18%	8.18%
5	**Required Operating Income @ 8.18% ROR**	**$ 2,115,126**	**$ 1,172,227**	**$ 11,747**	**$ 154,096**	**$ 770**	**$ 466,789**	**$ 1,566**	**$ 285,641**	**$ 9,138**	**$ 11,302**	**$ 1,849**
6	**Operating Expenses**											
7	Current Operating Expenses (Less Adjustments)	$ 4,159,626	$ 2,556,765	$ 22,510	$ 371,098	$ 1,300	$ 752,741	$ 2,446	$ 438,293	$ 3,531	$ 6,765	$ 4,176
8	Uncollectibles Expense	20,000	17,398	128	331	1	1,334	1	764	-	35	8
9	Depreciation Expense	1,939,404	1,083,370	10,658	144,200	688	428,719	1,416	260,334	2,732	4,716	2,569
10	Regulatory Commission Expense	153,393	84,536	849	11,045	56	34,737	116	21,099	316	482	157
11	Taxes Other than Income	44,148	24,330	244	3,179	16	9,998	33	6,073	91	139	45
12	Income Taxes	648,547	359,432	3,602	47,250	236	143,128	480	87,584	2,802	3,465	567
13	GRT	548,782	321,115	2,996	44,782	185	110,442	365	65,535	1,153	1,633	575
14	**Total Operating Expenses**	**$ 7,513,899**	**$ 4,446,947**	**$ 40,989**	**$ 621,886**	**$ 2,483**	**$ 1,481,098**	**$ 4,857**	**$ 879,683**	**$ 10,624**	**$ 17,235**	**$ 8,096**
15	**Total Revenue Requirement**	**$ 9,629,025**	**$ 5,619,174**	**$ 52,736**	**$ 775,982**	**$ 3,253**	**$ 1,947,887**	**$ 6,423**	**$1,165,324**	**$ 19,762**	**$ 28,537**	**$ 9,946**
16	**Revenue Deficiency**											
17	**Operating Revenues**											
18	Distribution Revenues	$ 6,401,996	$ 3,370,741	$ 24,594	$ 498,637	$ 676	$ 1,522,475	$ 1,028	$ 880,020	$ 13,496	$ 81,371	$ 8,957
19	Forfeited Discounts	31,122	27,073	199	516	1	2,076	1	1,189	-	55	12
20	Rent for Electric Property	273,619	137,412	1,663	14,663	114	68,475	231	50,219	168	516	158
21	Other Operating Revenues	22,899	12,057	88	1,784	2	5,446	4	3,148	48	291	32
22	**Total Operating Revenues**	**$ 6,729,636**	**$ 3,547,282**	**$ 26,544**	**$ 515,600**	**$ 794**	**$ 1,598,472**	**$ 1,264**	**$ 934,576**	**$ 13,712**	**$ 82,233**	**$ 9,159**
23	**Revenue Deficiency (Surplus)**	**$ 2,899,388**	**$ 2,071,892**	**$ 26,192**	**$ 260,383**	**$ 2,459**	**$ 349,415**	**$ 5,159**	**$ 230,748**	**$ 6,050**	**$ (53,695)**	**$ 787**
24	**Required Rate Increase (Decrease)**	**45.29%**	**61.47%**	**106.50%**	**52.22%**	**363.50%**	**22.95%**	**501.84%**	**26.22%**	**44.83%**	**-65.99%**	**8.78%**
25	**Relative Rate Increase**	**1.00**	**1.36**	**2.35**	**1.15**	**8.03**	**0.51**	**11.08**	**0.58**	**0.99**	**(1.46)**	**0.19**

Source: Company's Response to OCA-I-1, Attachment A (Schedule E).

Summary of Results of Alternative ACOS: Relative Rate of Return at Current Rates

Line No.	Account Description	Total Wellsboro	Residential Service: Residential (RS)	Residential Service: All Electric (RSAE)	Commercial and Industrial Service: Non-Residential (NRS)	Commercial and Industrial Service: Non-Res. Heating (NRH)	Commercial and Industrial Service: Commercial (CS)	Commercial and Industrial Service: Comm. Heating (CSH)	Commercial and Industrial Service: Industrial (IS)	Lighting Service: Municipal (MSL)	Lighting Service: Outdoor (POL)	Exchange Service (EU)
1	**Rate Base**											
2	Total Utility Plant	$ 44,666,856	$22,026,586	$ 244,894	$ 2,603,370	$ 20,160	$13,298,513	$ 45,822	$6,105,310	$103,376	$176,526	$ 42,297
3	Total Depreciation Reserve	(19,321,064)	(9,421,882)	(103,891)	(1,123,638)	(8,837)	(5,953,495)	(20,533)	(2,661,718)	14,067	(18,797)	(22,341)
4	Total Other Rate Base Items	511,488	306,321	3,002	47,933	212	103,708	466	48,336	643	162	707
5	**Total Rate Base**	**$ 25,857,280**	**$12,911,025**	**$ 144,004**	**$ 1,527,665**	**$ 11,536**	**$ 7,448,726**	**$ 25,755**	**$3,491,929**	**$118,086**	**$157,891**	**$ 20,663**
6	**Operating Income**											
7	**Operating Revenue**											
8	Distribution Revenues	$ 6,401,996	$ 3,370,741	$ 24,594	$ 498,637	$ 676	$ 1,522,475	$ 1,028	$ 880,020	$ 13,496	$ 81,371	$ 8,957
9	Forfeited Discounts	31,122	27,073	199	516	1	2,076	1	1,189	-	55	12
10	Rent for Electric Property	273,619	131,644	1,761	12,093	126	76,590	260	50,219	192	592	141
11	Other Operating Revenues	22,899	12,057	88	1,784	2	5,446	4	3,148	48	291	32
12	**Total Operating Revenues**	**$ 6,729,636**	**$ 3,541,515**	**$ 26,642**	**$ 513,029**	**$ 806**	**$ 1,606,588**	**$ 1,293**	**$ 934,576**	**$ 13,737**	**$ 82,309**	**$ 9,141**
13	**Operating Expenses**											
14	Distribution and Transmission Expenses	$ 1,602,629	$ 783,580	$ 10,147	$ 75,893	$ 726	$ 449,937	$ 1,524	$ 273,196	$ 1,948	$ 4,262	$ 1,414
15	Customer Account and Service Expenses	1,093,791	861,654	4,901	153,855	165	68,328	172	3,773	-	35	910
16	Administration and General Expenses	1,636,599	940,276	9,048	127,548	596	366,261	1,221	182,802	2,630	4,383	1,833
17	Depreciation Expense	1,939,404	988,567	10,621	121,146	828	544,402	1,857	260,334	3,162	6,040	2,445
18	General Taxes	44,148	21,687	242	2,549	20	13,211	46	6,073	103	176	42
19	Gross Receipts Tax	377,718	198,874	1,451	29,420	40	89,826	61	51,921	796	4,801	528
20	Income Taxes	(139,723)	(68,902)	(766)	(8,144)	(63)	(41,599)	(143)	(19,098)	(323)	(552)	(132)
21	**Total Operating Expenses**	**$ 6,554,565**	**$ 3,725,736**	**$ 35,645**	**$ 502,267**	**$ 2,311**	**$ 1,490,367**	**$ 4,737**	**$ 759,001**	**$ 8,316**	**$ 19,145**	**$ 7,041**
22	**Net Operating Income**	**$ 175,071**	**$ (184,221)**	**$ (9,003)**	**$ 10,762**	**$ (1,505)**	**$ 116,221**	**$ (3,443)**	**$ 175,575**	**$ 5,421**	**$ 63,164**	**$ 2,100**
23	**Rate of Return on Rate Base ("ROR")**	**0.68%**	**-1.43%**	**-6.25%**	**0.70%**	**-13.05%**	**1.56%**	**-13.37%**	**5.03%**	**4.59%**	**40.00%**	**10.16%**
24	**Relative Rate of Return ("RROR")**	**1.00**	**(2.11)**	**(9.23)**	**1.04**	**(19.27)**	**2.30**	**(19.75)**	**7.43**	**6.78**	**59.09**	**15.01**

Source: Company's Response to OCA-I-1, Attachment A (Schedule E).

Summary of Results of Alternative ACOS: Required Increase at Equalized Rates

Line No.	Account Description	Total Wellsboro	Residential Service: Residential (RS)	Residential Service: All Electric (RSAE)	Commercial and Industrial Service: Non-Residential (NRS)	Commercial and Industrial Service: Non-Res. Heating (NRH)	Commercial and Industrial Service: Commercial (CS)	Commercial and Industrial Service: Comm. Heating (CSH)	Commercial and Industrial Service: Industrial (IS)	Lighting Service: Municipal (MSL)	Lighting Service: Outdoor (POL)	Exchange Service (EU)
1	**Revenue Requirement**											
2	**Required Income Under Company's Proposed ROR**											
3	Total Rate Base	$25,857,280	$12,911,025	$ 144,004	$ 1,527,665	$ 11,536	$ 7,448,726	$ 25,755	$3,491,929	$ 118,086	$ 157,891	$ 20,663
4	Proposed Rate of Return	8.18%	8.18%	8.18%	8.18%	8.18%	8.18%	8.18%	8.18%	8.18%	8.18%	8.18%
5	**Required Operating Income @ 8.18% ROR**	**$ 2,115,126**	**$ 1,056,122**	**$ 11,780**	**$ 124,963**	**$ 944**	**$ 609,306**	**$ 2,107**	**$ 285,640**	**$ 9,659**	**$ 12,915**	**$ 1,690**
6	**Operating Expenses**											
7	Current Operating Expenses (Less Adjustments)	$ 4,159,626	$ 2,491,521	$ 23,114	$ 347,902	$ 1,417	$ 839,004	$ 2,763	$ 438,291	$ 3,878	$ 7,708	$ 4,028
8	Uncollectibles Expense	20,000	17,398	128	331	1	1,334	1	764	-	35	8
9	Depreciation Expense	1,939,404	988,567	10,621	121,146	828	544,402	1,857	260,334	3,162	6,040	2,445
10	Regulatory Commission Expense	153,393	75,351	842	8,857	70	45,903	158	21,099	357	610	146
11	Taxes Other than Income	44,148	21,687	242	2,549	20	13,211	46	6,073	103	176	42
12	Income Taxes	648,547	323,832	3,612	38,317	289	186,827	646	87,584	2,962	3,960	518
13	GRT	548,782	301,189	3,028	39,480	216	135,172	458	65,535	1,246	1,913	545
14	**Total Operating Expenses**	**$ 7,513,899**	**$ 4,219,544**	**$ 41,588**	**$ 558,582**	**$ 2,840**	**$ 1,765,854**	**$ 5,929**	**$ 879,680**	**$ 11,708**	**$ 20,442**	**$ 7,731**
15	**Total Revenue Requirement**	**$ 9,629,025**	**$ 5,275,666**	**$ 53,367**	**$ 683,545**	**$ 3,784**	**$ 2,375,160**	**$ 8,036**	**$1,165,320**	**$ 21,368**	**$ 33,358**	**$ 9,421**
16	**Revenue Deficiency**											
17	**Operating Revenues**											
18	Distribution Revenues	$ 6,401,996	$ 3,370,741	$ 24,594	$ 498,637	$ 676	$ 1,522,475	$ 1,028	$ 880,020	$ 13,496	$ 81,371	$ 8,957
19	Forfeited Discounts	31,122	27,073	199	516	1	2,076	1	1,189	-	55	12
20	Rent for Electric Property	273,619	131,644	1,761	12,093	126	76,590	260	50,219	192	592	141
21	Other Operating Revenues	22,899	12,057	88	1,784	2	5,446	4	3,148	48	291	32
22	**Total Operating Revenues**	**$ 6,729,636**	**$ 3,541,515**	**$ 26,642**	**$ 513,029**	**$ 806**	**$ 1,606,588**	**$ 1,293**	**$ 934,576**	**$ 13,737**	**$ 82,309**	**$ 9,141**
23	**Revenue Deficiency (Surplus)**	**$ 2,899,388**	**$ 1,734,151**	**$ 26,725**	**$ 170,516**	**$ 2,978**	**$ 768,572**	**$ 6,743**	**$ 230,744**	**$ 7,631**	**$ (48,951)**	**$ 280**
24	**Required Rate Increase (Decrease)**	**45.29%**	**51.45%**	**108.66%**	**34.20%**	**440.18%**	**50.48%**	**655.92%**	**26.22%**	**56.54%**	**-60.16%**	**3.13%**
25	**Relative Rate Increase**	**1.00**	**1.14**	**2.40**	**0.76**	**9.72**	**1.11**	**14.48**	**0.58**	**1.25**	**(1.33)**	**0.07**

Source: Company's Response to OCA-I-1, Attachment A (Schedule E).

Summary of Company's Proposed Revenue Allocation

Witness: Deupree
Docket No. R-2025-3054392
Exhibit MWD-3 (Wellsboro)

Line No.	Account Description	Total Wellsboro	Residential Service: Residential All Electric (RS)	Residential Service: (RSAE)	Commercial and Industrial Service: Non-Residential (NRS)	Non-Res. Heating (NRH)	Commercial (CS)	Comm. Heating (CSH)	Industrial (IS)	Lighting Service: Municipal (MSL)	Lighting Service: Outdoor (POL)	Exchange Service (EU)
1	**Allocated Cost of Service Results**											
2	Distribution Revenues	$ 6,401,996	$ 3,370,741	$ 24,594	$ 498,637	$ 676	$ 1,522,475	$ 1,028	$ 880,020	$ 13,496	$ 81,371	$ 8,957
3	Forfeited Discounts/Other Revenues	327,640	176,541	1,950	16,963	118	75,997	236	54,556	216	862	202
4	Current Operating Revenues	$ 6,729,636	$ 3,547,282	$ 26,544	$ 515,600	$ 794	$ 1,598,472	$ 1,264	$ 934,576	$ 13,712	$ 82,233	$ 9,159
5	Operating Income	$ 175,071	$ (341,253)	$ (8,527)	$ (33,679)	$ (1,256)	$ 313,495	$ (2,702)	$ 175,573	$ 6,186	$ 65,393	$ 1,842
6	Electric Rate Base	$ 25,857,280	$ 14,330,403	$ 143,611	$ 1,883,819	$ 9,415	$ 5,706,466	$ 19,138	$ 3,491,939	$ 111,717	$ 138,165	$ 22,606
7	**Rate of Return**	0.68%	-2.38%	-5.94%	-1.79%	-13.34%	5.49%	-14.12%	5.03%	5.54%	47.33%	8.15%
8	**Relative Rate of Return**	1.00	(3.52)	(8.77)	(2.64)	(19.71)	8.11	(20.85)	7.43	8.18	69.90	12.03
9	**Proposed Revenue Increase**											
10	Proposed Rate of Return	8.18%										
11	Current Operating Revenues	$ 6,729,636										
12	Proposed Operating Revenue Increase	2,899,388										
13	**Proposed Revenue Requirement**	$ 9,629,025										
14	**Proposed Revenue Allocation at Full Cost of Service**											
15	Distribution Revenues	$ 6,401,996	$ 3,370,741	$ 24,594	$ 498,637	$ 676	$ 1,522,475	$ 1,028	$ 880,020	$ 13,496	$ 81,371	$ 8,957
16	Forfeited Discounts/Other Revenues	327,640	176,541	1,950	16,963	118	75,997	236	54,556	216	862	202
17	Current Operating Revenues	$ 6,729,636	$ 3,547,282	$ 26,544	$ 515,600	$ 794	$ 1,598,472	$ 1,264	$ 934,576	$ 13,712	$ 82,233	$ 9,159
18	Total Revenue Requirement at Equal Rates of Return	9,629,025	5,619,174	52,736	775,982	3,253	1,947,887	6,423	1,165,324	19,762	28,537	9,946
19	Incremental Revenue Increase at Equal Rates of Return	$ 2,899,388	$ 2,071,892	$ 26,192	$ 260,383	$ 2,459	$ 349,415	$ 5,159	$ 230,748	$ 6,050	$ (53,695)	$ 787
20	**Precent Increase at Proposed Rate of Return**	**45.29%**	**61.47%**	**106.50%**	**52.22%**	**363.50%**	**22.95%**	**501.84%**	**26.22%**	**44.83%**	**-65.99%**	**8.78%**
21	**Relative Increase**	**1.00**	**1.36**	**2.35**	**1.15**	**8.03**	**0.51**	**11.08**	**0.58**	**0.99**	**(1.46)**	**0.19**
22	**Proposed Mitigated Revenue Allocation**											
23	Current Distribution Revenues	$ 6,401,996	$ 3,370,741	$ 24,594	$ 498,637	$ 676	$ 1,522,475	$ 1,028	$ 880,020	$ 13,496	$ 81,371	$ 8,957
24	Proposed Distribution Revenue Increase	2,899,388	1,668,860	14,885	236,093	507	601,598	771	354,548	6,155	12,757	3,214
25	**Proposed Distribution Revenues**	$ 9,301,384	$ 5,039,601	$ 39,479	$ 734,730	$ 1,184	$ 2,124,073	$ 1,799	$ 1,234,568	$ 19,651	$ 94,128	$ 12,171
26	**Proposed Revenue Change (%)**	**45.29%**	**49.51%**	**60.52%**	**47.35%**	**75.00%**	**39.51%**	**75.00%**	**40.29%**	**45.60%**	**15.68%**	**35.89%**
27	**Relative Proposed Revenue Increase**	**1.00**	**1.09**	**1.34**	**1.05**	**1.66**	**0.87**	**1.66**	**0.89**	**1.01**	**0.35**	**0.79**

Source: Company's Response to I&E-RE-1-D, Attachment A.

Summary of Alternative Proposed Revenue Allocation

Witness: Deupree
Docket No. R-2025-3054392
Exhibit MWD-4 (Wellsboro)

Line No.	Account Description	Total Wellsboro	Residential Service: Residential All Electric (RS)	Residential Service: (RSAE)	Commercial and Industrial Service: Non-Residential (NRS)	Non-Res. Heating (NRH)	Commercial (CS)	Comm. Heating (CSH)	Industrial (IS)	Lighting Service: Municipal (MSL)	Lighting Service: Outdoor (POL)	Exchange Service (EU)
1	**Allocated Cost of Service Results**											
2	Distribution Revenues	$ 6,401,996	$ 3,370,741	$ 24,594	$ 498,637	$ 676	$ 1,522,475	$ 1,028	$ 880,020	$ 13,496	$ 81,371	$ 8,957
3	Forfeited Discounts/Other Revenues	327,640	170,774	2,048	14,392	130	84,112	265	54,556	241	938	185
4	Current Operating Revenues	$ 6,729,636	$ 3,541,515	$ 26,642	$ 513,029	$ 806	$ 1,606,588	$ 1,293	$ 934,576	$ 13,737	$ 82,309	$ 9,141
5	Operating Income	$ 175,071	$ (184,221)	$ (9,003)	$ 10,762	$ (1,505)	$ 116,221	$ (3,443)	$ 175,575	$ 5,421	$ 63,164	$ 2,100
6	Electric Rate Base	$ 25,857,280	$ 12,911,025	$ 144,004	$ 1,527,665	$ 11,536	$ 7,448,726	$ 25,755	$ 3,491,929	$ 118,086	$ 157,891	$ 20,663
7	**Rate of Return**	0.68%	-1.43%	-6.25%	0.70%	-13.05%	1.56%	-13.37%	5.03%	4.59%	40.00%	10.16%
8	**Relative Rate of Return**	1.00	(2.11)	(9.23)	1.04	(19.27)	2.30	(19.75)	7.43	6.78	59.09	15.01
9	**Proposed Revenue Increase**											
10	Proposed Rate of Return	16.52%										
11	Current Operating Revenues	$ 6,729,636										
12	Proposed Operating Revenue Increase	2,899,388										
13	**Proposed Revenue Requirement**	$ 9,629,025										
14	**Proposed Revenue Allocation at Full Cost of Service**											
15	Distribution Revenues	$ 6,401,996	$ 3,370,741	$ 24,594	$ 498,637	$ 676	$ 1,522,475	$ 1,028	$ 880,020	$ 13,496	$ 81,371	$ 8,957
16	Forfeited Discounts/Other Revenues	327,640	170,774	2,048	14,392	130	84,112	265	54,556	241	938	185
17	Current Operating Revenues	$ 6,729,636	$ 3,541,515	$ 26,642	$ 513,029	$ 806	$ 1,606,588	$ 1,293	$ 934,576	$ 13,737	$ 82,309	$ 9,141
18	Total Revenue Requirement at Equal Rates of Return	9,629,025	5,275,666	53,367	683,545	3,784	2,375,160	8,036	1,165,320	21,368	33,358	9,421
19	Incremental Revenue Increase at Equal Rates of Return	$ 2,899,388	$ 1,734,151	$ 26,725	$ 170,516	$ 2,978	$ 768,572	$ 6,743	$ 230,744	$ 7,631	$ (48,951)	$ 280
20	**Precent Increase at Proposed Rate of Return**	**45.29%**	**51.45%**	**108.66%**	**34.20%**	**440.18%**	**50.48%**	**655.92%**	**26.22%**	**56.54%**	**-60.16%**	**3.13%**
21	**Relative Increase**	**1.00**	**1.14**	**2.40**	**0.76**	**9.72**	**1.11**	**14.48**	**0.58**	**1.25**	**(1.33)**	**0.07**
22	**Proposed Mitigated Revenue Allocation**											
23	Step One: Company Modeled Distribution Revenue Increase											
24	Current Distribution Revenues	$ 6,401,996	$ 3,370,741	$ 24,594	$ 498,637	$ 676	$ 1,522,475	$ 1,028	$ 880,020	$ 13,496	$ 81,371	$ 8,957
25	Proposed Distribution Revenue Increase	2,899,388	1,582,212	14,999	212,602	507	709,948	771	354,635	6,578	14,057	3,080
26	Proposed Distribution Revenues after Step One	$ 9,301,384	$ 4,952,953	$ 39,593	$ 711,239	$ 1,184	$ 2,232,423	$ 1,799	$ 1,234,655	$ 20,074	$ 95,428	$ 12,036
27	Step Two: RSAE, NRH, and CSH Cap of 1.25 Times System Average											
28	Cap of 1.25 Times System Average	56.61%										
29	RSAE, NRH, and CSH Cap of 1.25 Times System Average	$ 14,888		$ 13,923		$ 383		$ 582				
30	Step Two Amount to be Reallocated	$ 1,389		$ 1,076		$ 124		$ 189				
31	Basis for Reallocation	$ 6,375,697	$ 3,370,741		$ 498,637		$ 1,522,475		$ 880,020	$ 13,496	$ 81,371	$ 8,957
32	Step Two Reallocation	$ 1,389	$ 734		$ 109		$ 332		$ 192	$ 3	$ 18	$ 2
33	Proposed Distribution Revenue Increase after Step Two	$ 2,899,388	$ 1,582,946	$ 13,923	$ 212,711	$ 383	$ 710,279	$ 582	$ 354,826	$ 6,581	$ 14,075	$ 3,081
34	**Total Proposed Distribution Revenues**	**$ 9,301,384**	**$ 4,953,687**	**$ 38,517**	**$ 711,348**	**$ 1,059**	**$ 2,232,755**	**$ 1,610**	**$ 1,234,847**	**$ 20,077**	**$ 95,445**	**$ 12,038**
35	**Proposed Revenue Change (%)**	**45.29%**	**46.96%**	**56.61%**	**42.66%**	**56.61%**	**46.65%**	**56.61%**	**40.32%**	**48.76%**	**17.30%**	**34.40%**
36	**Relative Proposed Revenue Increase**	**1.00**	**1.04**	**1.25**	**0.94**	**1.25**	**1.03**	**1.25**	**0.89**	**1.08**	**0.38**	**0.76**

Source: Company's Response to I&E-RE-1-D, Attachment A.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No. R-2025-3054392
	:	
Wellsboro Electric Company	:	

VERIFICATION

I, Michael W. Deupree, hereby state that the facts above set forth in my Direct Testimony, OCA Statement No. 3, are true and correct to the best of my knowledge, information, and belief and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa.C.S. § 4904 (relating to unsworn falsification to authorities).

DATED: July 15, 2025

Signature:
Michael W. Deupree

Address: Acadian Consulting Group
5800 One Perkins Place Drive
Suite 5-F
Baton Rouge, LA 70808

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	Docket No.: R-2025-3054394
v.	:	
	:	
Citizens' Electric Company of Lewisburg, PA	:	

DIRECT TESTIMONY

OF

LeeAnn Wise

On behalf of the

PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

Date Served: July 15, 2025

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Introduction

Q. Please state your name and business address.

A. My name is LeeAnn Wise. My business address is 555 Walnut Street, Forum Place 5th Floor, Harrisburg, Pennsylvania 17101.

Q. By whom are you employed and in what capacity?

A. I am employed as a Regulatory Analyst by the Pennsylvania Office of Consumer Advocate (OCA).

Q. Please describe your educational background and qualifications to provide testimony in this case.

A. I have a Master's Degree in Business Administration from Shippensburg University and a Bachelor of Science degree in Professional Accountancy from the University of Pennsylvania. I have over fifteen years of experience in call center operations, with a strong background managing teams, improving workflow, and delivering outstanding customer service. Additionally, I have received internal training while working for the Office of Consumer Advocate (OCA). See Appendix A for additional information about my qualifications.

Q. What is the purpose of your testimony in this case?

A. I am filing the Direct Testimony in response to the application filed on April 30, 2025, by Citizens' Electric Company of Lewisburg, PA (Citizens or Company) to increase its base rate for electric service. The purpose of my testimony in this case is to address specific concerns regarding processing fees of $3.95 assessed to debit and credit card payments, how and when a security deposit is required, and the current payment arrangements available to customers.

Q. Have you previously provided testimony before the Pennsylvania Public Utility Commission?

A. No, I have not submitted testimony before the Pennsylvania Public Utility Commission.

Q. Have you prepared Exhibits to accompany your testimony?

A. No.

Summary

Q. Please describe the proposal for rate increase filed by Citizens Electric.

A. Citizens Electric proposes to increase its electric distribution rates by $1.79 million per year or about a 29.6% increase to annual distribution revenue,[1] with a proposed effective date of June 29, 2025. Based on this filing, residential customers are facing monthly bill increases in distribution rates of up to nearly 31.9%.[2] More specifically, if approved as filed, residential customers using 1,250 kwh per month would see increases to their monthly bills by 31.9% on a distribution rate only basis, including the fixed customer charge and volumetric distribution rates.[3] The Company noticed customers that they would see a monthly bill increase of 11%, on a total rate basis, including commodity charges; however, the commodity charges are not at issue in this proceeding. Citizens Electric's last rate case was in January 2023 and was settled for an annual revenue increase of $930,000.[4]

Q. Please summarize your conclusions and recommendations.

A. First, I recommend eliminating the payment fee imposed on customers paying their bills via credit or debit card through the Company's web-based and mobile application, known

[1] Citizens Statement No.1 pg.3 ln. 11-14.
[2] Exhibit HSG-1 Schedule B8-1 pg. 1 ln 8.
[3] Exhibit HSG-1 Schedule B8-2 pg. 1 ln. 8.
[4] Citizens Statement No. 4 pg.4 ln. 11-13.

as SmartHub, which allows customers to view billing statements, monitor energy usage, and make payments electronically. While SmartHub offers convenience and promotes energy monitoring and conservation, the implementation and associated fee structure raises serious concerns. The Company imposes a fee of $3.95 on customers paying their bills via credit or debit card. Today, where electronic and paperless transactions are the norm, assessing an additional fee is contrary to the principles of fair utility service.

Next, as to screening for low-income customers when assessing security deposits, I recommend that the Company should show in rebuttal that it has formal policies and procedures in place addressing these practices in which their employees are trained. If not, the Company should develop and implement formal policies or procedures to formalize these practices and ensure that employees are trained in them.

Finally, I recommend several improvements to ensure the success of customer payment arrangements.

Customer Payment Fees

Q. What is SmartHub?

A. SmartHub is a web and mobile application administered primarily by the Company, with support provided as needed by the software vendor and C&T IT.[5] Customers can use SmartHub to pay bills and are assessed a $3.95 fee, view usage, and billing statements.[6]

[5] Citizens response to OCA VI-5
[6] Citizens response to OCA-VI-1.

Q. What are the key functions of the SmartHub application?

A. Citizens' Electric implemented the SmartHub platform for customers to view their bills, monitor usage data, and process payments electronically. The adoption of technology provides a user-friendly method for customers to access their account using a mobile app or online. Many of the Companies' customers have opted to utilize SmartHub to view their account. The tool is helpful in providing customers with a view at their usage trends, which allows for better management of energy consumption.

Q. Should the Company continue using SmartHub?

A. Yes, the use of web-based and online applications is highly effective in providing customers with real-time access to their account information. It is my recommendation that the Company continue its utilization of the SmartHub platform and explore the implementation of additional technological enhancements such as alerts for unusually high usage, real-time notifications of outages, and estimated charges based on month-to-date usage, to further improve the quality and efficiency of customer service.

Q. Does Citizens Electric charge customers a processing fee for electronic payments?

A. Yes, the company charges a $3.95 fee when a customer pays using SmartHub or via telephone.[7]

Q. Why does the company charge this $3.95 fee?

A. The Company charges $3.95 fee to recover costs incurred from third-party vendor for processing electronic payments.[8]

[7] Citizens Electric response to OCA-III-3.
[8] Citizens Electric response to OCA-VI-1.

Q. How much revenue does the Company earn from charging the $3.95 payment fee?

A. In 2024, the amount collected from customers and remitted to the third-party vendor was $40,010.[9] The fees are passed directly onto the third-party vendor. Therefore, there would be no revenue earned by Citizens Electric.[10]

Q. If the payment fee was eliminated, how much revenue would be forfeited by the Company?

A. If the Company were to eliminate the fee, it would not result in any revenue loss. However, the Company would claim the expense as a distribution cost for recovery through rates. The vendor fees for the last two and a half years are shown below.[11]

	Third-Party Vendor Fees		
	2023	**2024**	**2025**
January	3,049	3,614	3,440
February	2,820	3,203	3,420
March	3,247	3,393	3,749
April	2,884	3,512	3,642
May	3,286	3,417	3,322
June	2,895	3,065	
July	2,970	3,358	
August	3,002	3,342	
September	3,121	3,358	
October	3,136	3,429	
November	3,018	3,132	
December	3,089	3,188	
Total	**$ 36,518**	**$ 40,010**	**$ 17,573**

Q. Is the $3.95 payment fee reasonable?

A. No. The Company accepts checks, money orders, or bank transfers with no processing fees to consumers. A customer can also enroll in direct debit withdrawal from their bank account with no processing fees. However, a fee of $3.95 is assessed when paying using a debit or credit card through SmartHub. Although assessing fees for payments are not prohibited by Chapter 56, the effect is to increase the rates for customers who pay by

[9] Citizens Electric response to OCA-VI-1.
[10] Citizens Electric response to OCA-VI-3.
[11] Citizens Electric response to OCA-VI-4.

certain options that are normative in today's economy. While the Company does not benefit from these fees, customers are penalized by the imposed payment conditions, resulting in higher costs for customers choosing to use SmartHub or by Interactive Voice Response (IVR) payment compared to other customers. The IVR system allows callers to interact with the company's phone system through voice prompts. The system uses pre-recorded information and routes customers to live agents. In my opinion, this policy is unreasonable and discriminates against those customers using credit and debit charge to pay for their service. The Company incurs administrative costs for processing cash and check payments, that are passed onto customers through the Company's rate base. Credit and debit charge payments should be handled in the same manner. Customers pay for household goods via credit and debit cards without being assessed an additional fee. Paying your utility bill should not be any different. The policy of charging a fee is also quite harmful to lower income customers who may be unbanked and rely on pre-purchase debit cards to make payments.[12]

Q. Do you have any recommendations?

A. Yes, I recommend as part of their rate request, that the Company should be required to absorb the fee for SmartHub and IVR payment and the revenue requirement be adjusted accordingly. The costs for the third-party vendor are within the Company's control since they are negotiated contracts. The reasonable cost of offering a variety of payment methods without additional customer fees on individual customers should be reflected in

[12] According to the 2023 FDIC National Survey of Unbanked and Underbanked Households, 5.9% of households were using general purchase reloadable prepaid cards and 49.7% of all households were using nonbank online payment services, such as PayPal, Venmo, and Cash App. The use of prepaid debit cards was much higher among unbanked households. Compared with banked households, substantially higher shares of unbanked households used online payment services and prepaid cards in ways that substitute for some of the core financial transactions that can be conducted using a bank account. - https://www.fdic.gov/household-survey/2023-fdic-national-survey-unbanked-and-underbanked-households-executive-summary.

the Company's revenue requirement, the same as the costs associated with processing checks and accepting payment at authorized locations.

Q. What are the benefits of your recommendation?

A. Providing a payment method through an application like SmartHub provides convenience for the Company and its customers, and is considered good practice.[13] However, when a utility customer makes multiple payments during a month, fees on credit and debit payments undercut their ability to apply funds to the payment of actual utility services. Citizens Electric should accept payment by any lawful means without additional fees. The reasonable cost of offering a variety of payment methods without additional customer fees should be reflected in the Company's revenue requirement, like the costs associated with processing checks and ACH payments for which fees are not charged. This recommendation is in line with a growing trend among Pennsylvania utilities[14] to eliminate payment fees and reflects the expectation of most customers to use online electronic payments without additional fees.

Q. Did you calculate the revenue adjustments needed if the payment processing fee of $3.95 was eliminated for customers?

A. No, I have not calculated the revenue adjustment. This calculation will be addressed by OCA witness Greg Meyer in his revenue requirement and accounting testimony. See OCA Statement No. 1.

[13] These and other reasons are discussed in NASUCA Resolution 2012-07. https://www.nasuca.org/2012-07-urgingutilities-to-eliminate-convenience-fees-for-paying-utility-bills-with-debit-and-credit-cards-and-urging-appropriatestate-regulatory oversight/.

[14] In the last several years Pittsburgh Water (Formally known as Pittsburgh Water and Sewer Authority), York Water, and Pennsylvania American Water have eliminated credit card and debit card payment fees.

Security Deposits

Q. Does the Company charge a security deposit?

A. Yes, The Company assesses a security deposit when the customer does not meet credit score requirements.

Q. Does the Company screen to ensure low-income customers do not have to pay a security deposit?

A. The Company states, if, after a customer is informed that a security deposit is due, the customer indicates that they may have difficulty paying the deposit, customer service staff will inform the customer that the deposit may be waived if they meet income requirements. If the customer wishes to proceed, staff will verify income and waive the deposit if appropriate. For customers meeting Level 1 criteria under Federal Poverty Income Guidelines, the deposit is waived. The Company states that it adheres to Chapter 56 of the Public Utility Code when determining deposit amounts and waiver eligibility.[15]

Level 1 (100% of FPL)

Household Size	Annual Income
1	$15,060
2	$20,440
3	$25,820
4	$31,200

Q. Do you have any comments?

A. Yes, the Company states they wait until the customer indicates they may have difficulty paying the deposit.[16] Many low-income customers may be unwilling or hesitant to disclose their financial hardship or income status. Additionally, the Company did not

[15] Citizens response to OCA-VI-8.
[16] Citizens response to OCA-VI-8

show that it has formal policies and procedures to support the practice of verifying income prior to charging a security deposit.

Q. Does the Company refund customers who have paid a security deposit and should not have?

A. Yes, customers who are confirmed as low-income prior to deposit are not charged a deposit. If the Company confirms the low-income status of a customer who has already been charged a deposit, the Company states that the deposit is credited to their account balance or refunded to them directly, less than any outstanding balance on their account.[17] The Company did not show that it has formal policies and procedures to support the practice of refunding security deposits where it should not have been charged.

Q. Do you have any recommendations?

Yes, while the Company should continue its practices of (1) verifying income levels and number of household members before requiring a security deposit, and (2) refunding security deposits that should not have been charged, the Company should show in rebuttal that it has formal policies and procedures in place addressing these practices in which their employees are trained. If not, the Company should develop and implement formal policies or procedures to formalize these practices and ensure that employees are trained in them.

Q. Do you have any further recommendations?

A. Yes, the Company should permit the customer to decide whether they want to receive the returned security deposit as a refund or credit to their utility account balance and decide whether they want that security deposit to be applied to their outstanding balance.

[17] Citizens response to OCA-VI-10.

Q. Why is your further recommendation reasonable?

A. Any security deposit that was unfairly assessed constitutes funds that rightfully belong to the customer. As such, the customer should retain the sole discretion over how those funds are utilized. For individuals living in poverty, financial management is often a day-to-day challenge. Allowing customers to have access to their own money provides them with greater autonomy and flexibility to address their most pressing needs. This approach may be more beneficial to the customer than applying the funds as credit to a future utility bill, which may not align with their immediate financial needs.

Payment Plans

Q. Does the Company offer payment plans?

A. Yes, the Company offers payment plans and encourages all customers who are having difficulty paying their account balance to discuss payment arrangements, regardless of income level.[18]

Q. How does the Company establish payment arrangements?

A. The Manager of Customer Service directly handles the negotiation and establishment of all long-term payment arrangements, including Commission payment arrangements, and is trained in the relevant Commission regulations and guidelines. Customer Service Representatives are trained and authorized to negotiate short-term arrangements—up to two months—with customers.[19]

[18] Citizens response to OCA-VI-16.
[19] Citizens response to OCA-III-2.

Q. Please describe the payment plans offered by the Company.

A. The Company offers payment plans to their customers, and states that it follows the Commission's Bureau of Consumer Services payment arrangement guidelines in determining the length of the arrangement, as follows:[20]

The monthly arrangement amount due is calculated by dividing the past due balance by the term of the arrangement and adding the average monthly bill.

Arrangement amounts may be adjusted periodically if the customer's average bill changes (either due to a change in average usage, or a change in applicable distribution or generation charges and/or rates). Changes to arrangement amounts are communicated to customers in advance of billing.[21]

Q. Does the Company track how successful its payment arrangements are in recovering payment, customer retention, and reducing late payments?

A. No, the Company does not currently track the success of their payment arrangements in terms of qualifying customers entering into them, customers being able to pay the amounts owed under the terms of the arrangements, and customers' ability to maintain service.[22]

Q. Do you have any concerns about the Company not collecting data on the success of its payment arrangements?

A. Yes, offering payment plans represents an effort to tailor payment obligations in line with a customer's financial means, and promotes fair and continued access to utility services. However, without performance metrics or ongoing analysis, it is difficult to determine

[20] Citizens response to OCA-VI-16.
[21] Citizens response to OCA-VI-16.
[22] Citizens response to OCA-VI-19.

whether these plans are achieving their intended goals, such as improving customer repayment rates or reducing delinquencies. In my professional opinion, the absence of such oversight may reflect a lack of due diligence and raise concerns about the company's ability to manage financial risk or make informed decisions regarding customer repayment strategies.

Q. Do you have any recommendations?

A. Yes, I recommend the Company establish metrics for measuring the success of payment plans and set documented plan policies, including how the Federal Poverty Income ranges are used, what verification is needed for low-income verification, and how payments and terms are calculated. The Company should also make sure payment options are clearly communicated to customers through all means of communication used, especially to low-income customers. In addition, I would also recommend the Company maintain internal controls on the number of payment plans offered, customers enrolled, and successful completion of said payments agreements. The Company should also consider separating plans by income levels. The Company should routinely evaluate its payment arrangements to identify the factors that contribute to the success or failure of the agreements and take steps to internalize the results of that analysis in its implementation of payment arrangements and communications with customers.

Q. Does this conclude your testimony.

A. Yes.

Qualifications of LeeAnn Wise, Senior Regulatory Analyst

Education:

- 2008, Master of Business Administration, Shippensburg University
- 1989, Bachelor of Science, Professional Accountancy, The Pennsylvania State University

Experience:

- January 2025 to Present, Senior Regulatory Analyst, Pennsylvania Office of Consumer Advocate
- January 2021 to January 2024, Senior Manager Finance & Accounting, COMCAST Corporation – Business Services
- January 2008 to January 2021, Manager Finance & Accounting, COMCAST Corporation
- May 1989 to March 2008, Senior Accountant, Penn Credit Corporation

Current Role Description:

I am currently employed by the Pennsylvania Office of Consumer Advocate (OCA) as a Senior Regulatory Analyst. In this position, my responsibilities include reviewing utility company filings with the Pennsylvania Public Utility Commission (Commission) and analyzing the financial, economic, accounting, rate of return, customer service, quality of service, and other technical or policy issues that are relevant to the filings. Additionally, I am tasked with preparing recommendations for the OCA's involvement in utility filings before the Commission, presenting written and oral testimony on behalf of the OCA.

Relevant Training and Experience:

I have over fifteen years of experience overseeing and evaluating planning and analysis for a $40 million customer call center operations, overseeing budgeting, forecasting, and variance analysis to improve financial accuracy and support strategic decision-making by senior leadership. This includes my employment at Comcast Corporation as a Manager and Senior Manager in Finance & Accounting, where I provided oversight of performance metrics, evaluating disputes and time to resolve, call-handle times, average speed of answer, and ensuring customer interactions align with policy standards. My training includes a sound understanding of the best practices in customer service delivery, call tracking protocols, and the importance of consistent documentation to support customer communication and reliability.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No. R-2025-3054394
	:	
Citizens' Electric Co. of Lewisburg, PA	:	

VERIFICATION

I, LeeAnn Wise, hereby state that the facts above set forth in my Direct Testimony, OCA Statement No. 4, are true and correct to the best of my knowledge, information, and belief and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa.C.S. § 4904 (relating to unsworn falsification to authorities).

DATED: July 15, 2025

Signature: */s/ LeeAnn Wise*
LeeAnn Wise

Address: Office of Consumer Advocate
555 Walnut Street
Harrisburg, PA 17101

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	Docket No.: R-2025-3054393
v.	:	
	:	
Valley Energy, Inc.	:	

DIRECT TESTIMONY

OF

LeeAnn Wise

On behalf of the

PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

Date Served: July 15, 2025

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Introduction

Q. Please state your name and business address.

A. My name is LeeAnn Wise. My business address is 555 Walnut Street, Forum Place 5th Floor, Harrisburg, Pennsylvania 17101.

Q. By whom are you employed and in what capacity?

A. I am employed as a Regulatory Analyst by the Pennsylvania Office of Consumer Advocate (OCA).

Q. Please describe your educational background and qualifications to provide testimony in this case.

A. I have a Master's Degree in Business Administration from Shippensburg University and a Bachelor of Science degree in Professional Accountancy from the University of Pennsylvania. I have over fifteen years of experience in call center operations, with a strong background managing teams, improving workflow, and delivering outstanding customer service. Additionally, I have received internal training while working for the OCA. See Appendix A for additional information about my qualifications.

Q. What is the purpose of your testimony in this case?

A. I am filing the Direct Testimony in response to the application filed on April 30, 2025, by Valley Energy Inc. (Valley or Company) to increase its base rate for natural gas services. The purpose of my testimony in this case is to address specific concerns regarding processing fees of $3.95 assessed to debit and credit card payments, how and when a security deposit is required, and the current payment arrangements available to the Company's customers.

Q. Have you previously provided testimony before the Pennsylvania Public Utility Commission?

A. No, I have not submitted testimony before the Pennsylvania Public Utility Commission.

Q. Have you prepared Exhibits to accompany your testimony?

A. No.

Summary

Q. Please describe the proposal for a rate increase filed by Valley Energy Inc.

A. Valley proposes to increase its natural gas distribution rates by $1.6 million per year or about a 25.1% increase to distribution annual revenue,[1] with a proposed effective date of June 29, 2025. Based on this filing, residential customers are facing monthly bill increases in distribution rates of up to nearly 30%.[2] More specifically, if approved as filed, residential customers using 76 ccf per month would see increases to their monthly bills by 29.66% on a distribution rate only basis, including the fixed customer charge and volumetric distribution rates.[3] The Company noticed customers that they would see a monthly bill increase by 18.00%, on a total bill basis, including commodity charges; however, the commodity charges are not at issue in this proceeding. Valley's last rate increase was in February 2023 that settled for an annual revenue increase of $958,000.[4]

Q. Please summarize your conclusions and recommendations.

A. First, I recommend eliminating the payment fee imposed on customers paying their bills via credit or debit card through the Company's web-based and mobile application, known as SmartHub, which allows customers to view billing statements, monitor energy usage,

[1] Valley Statement No.1 pg.3 ln. 9-16.
[2] Exhibit HSG-1, Schedule B5-2 pg. 1 ln. 6.
[3] Exhibit_HSG-1, Schedules B5-1-B5-2.
[4] Valley Statement No.4 pg. 3, ln. 11-15.

and make payments electronically. While SmartHub offers convenience and promotes energy monitoring and conservation, the implementation and associated fee structure raise serious concerns. The Company imposes a fee of $3.95 on customers paying their bills via credit or debit card. Today, where electronic and paperless transactions are the norm, accessing an additional fee is contrary to the principles of reasonable utility service.

Next, as to screening for low-income customers when assessing security deposits, I recommend that the Company should show in rebuttal that it has formal policies and procedures in place addressing its practices and that their employees are trained in them. If not, I recommend that the Company develop and implement formal policies or procedures to formalize these practices and ensure that employees are trained in them. I further recommend that the Company permit the customer to decide whether they want to receive the returned security deposit as a refund or credit to their utility account balance.

Finally, I recommend several improvements to ensure the success of customer payment arrangements.

Customer Payment Fees

Q. What is SmartHub?

A. SmartHub is a web and mobile application administered primarily by the Company with support provided as needed by the software vendor and C&T IT.[5] Customers can use SmartHub to pay bills and are assessed a $3.95 fee, view usage, and billing statements.[6]

Q. What are the key functions of the SmartHub application?

A. Valley implemented the SmartHub platform for customers to view their bills, monitor usage data, and process payments electronically. The adoption of technology provides a user-friendly method for customers to access their account using a mobile app or online. Many of the Company's customers have opted to utilize SmartHub to view their account. The tool is helpful in providing customers with a view at their usage trends, which allows for better management energy consumption.

Q. Should the Company continue using SmartHub?

A. Yes, the use of web-based and online applications is highly effective in providing customers with real-time access to their account information. It is my recommendation that the Company continue its utilization of the SmartHub platform and explore the implementation of additional technological enhancements such as alerts for unusually high usage, real-time notifications of outages, and estimated charges based on month-to-date usage, to further improve the quality and efficiency of customer service.

to further improve the quality and efficiency of customer service.

[5] Valley Energy response to OCA-VI-5.
[6] Valley Energy response to OCA-VI-1.

Q. Does Valley charge customers a processing fee for electronic payments?

A. Yes, the company charges a $3.95 fee when a customer pays using SmartHub or via telephone.[7]

Q. Why does the company charge this $3.95 fee?

A. The Company charges $3.95 fee to recover costs incurred from third-party vendor for processing electronic payments.[8]

Q. How much revenue does the Company earn from charging the $3.95 payment fee?

A. In 2024, the amount collected from customers and remitted to the third-party vendor was $66,253.35.[9] The fees are passed directly onto the third-party vendor. Therefore, there would be no revenue earned by Valley.[10]

Q. If the payment fee was eliminated, how much revenue would be forfeited by the Company?

A. The $3.95 fee assessed to customers is passed directly onto the third-party vendor. If the Company were to eliminate the fee, it would not result in any revenue loss. However, the Company would claim the expense as a distribution cost for recovery through rates.

Q. Is the $3.95 processing fee reasonable?

No. The Company accepts checks, money orders, or bank transfers with no processing fees to consumers. A customer can also enroll in direct debit withdrawal from their bank account without a processing fee. However, a fee of $3.95 is assessed when paying using a debit or credit card through SmartHub. Although assessing fees for payments are not prohibited by Chapter 56, the effect is to increase the rates for customers who pay by certain

[7] Valley response to OCA-III-3.
[8] Valley response to OCA-VI-1.
[9] Valley response to OCA-VI-3.
[10] Valley response to OCA-VI-4.

options that are normative in today's economy. While the Company does not benefit from these fees, customers are penalized by the payment conditions imposed, resulting in higher costs for customers choosing to use SmartHub or Interactive Voice Response (IVR) payment compared to other customers. The IVR system allows callers to interact with the company's phone system through voice prompts. The system uses pre-recorded information and routes customers to live agents. In my opinion, this policy could be considered unreasonable discrimination in service. The Company incurs administrative costs for processing cash and check payments, that are passed onto customers through the Company's rate base. Credit and debit charge payments should be handled in the same manner. Customers pay for household goods via credit and debit cards without being assessed an additional fee. Paying your utility bill should not be any different. The policy of charging a fee is quite harmful to lower income customers who may be unbanked and rely on pre-purchase debit cards to make payments.[11]

Q. Do you have any recommendations?

A. Yes. I recommend that the Company should be required to absorb the fee for SmartHub and IVR payment and the revenue requirements be adjusted accordingly. The costs for the third-party vendor are within the Company's control since they are negotiated contracts. The reasonable cost of offering a variety of payment methods without additional customer fees on individual customers should be reflected in the Company's

[11] According to the 2023 FDIC National Survey of Unbanked and Underbanked Households, 5.9% of households were using general purchase reloadable prepaid cards and 49.7% of all households were using nonbank online payment services, such as PayPal, Venmo, and Cash App. The use of prepaid debit cards was much higher among unbanked households. Compared with banked households, substantially higher shares of unbanked households used online payment services and prepaid cards in ways that substitute for some of the core financial transactions that can be conducted using a bank account. - https://www.fdic.gov/household-survey/2023-fdic-national-survey-unbanked-and-underbanked-households-executive-summary.

revenue requirement, like the costs associated with processing checks and accepting payment at authorized locations.

Q. What are the benefits of your recommendations?

A. Providing a payment method through an application like SmartHub provides convenience for the Company and its customers and is considered good practice.[12] Also, when a utility customer makes multiple payments during a month, fees on credit and debit payments undercut their ability to apply funds to the payment of actual utility services. Valley Energy Inc. should accept payment by any lawful means without additional fees and reflect reasonable and prudent costs to process these payments in its revenue requirement. This recommendation is in line with a growing trend among Pennsylvania utilities[13] to eliminate payment fees and reflects the expectation of most customers to use online electronic payments without additional fees.

Q. Did you calculate the revenue adjustments needed if the payment processing fee of $3.95 was eliminated for customers?

A. No, I have not calculated the revenue adjustment. This calculation will be addressed by OCA witness Greg Meyer in his revenue requirement and accounting testimony. See OCA Statement No. 1.

[12] These and other reasons are discussed in NASUCA Resolution 2012-07. https://www.nasuca.org/2012-07-urgingutilities-to-eliminate-convenience-fees-for-paying-utility-bills-with-debit-and-credit-cards-and-urging-appropriatestate-regulatory oversight.

[13] In the last several years Pittsburgh Water (formerly Pittsburgh Water and Sewer Authority), York Water, and Pennsylvania American Water have eliminated credit and debit card payment fees.

Security Deposits

Q. Does the Company charge a security deposit?

A. Yes, The Company assesses a security deposit when the customer does not meet credit score requirements.

Q. Does the company screen to ensure low-income customers do not have to pay a security deposit?

A. Yes, the Company verifies income prior to charging a security deposit and uses Federal Poverty Level guidelines are followed to determine income levels.[14] However, the Company did not show that it has formal policies and procedures to support the practice of verifying income prior to charging a security deposit.

Q. Does the Company refund customers who have paid a security deposit and should not have?

A. Yes, the security deposit would be refunded by crediting the customer's account.[15] Valley's practice does not provide the customer with the choice of receiving a refund or credit to their utility account. Also, the Company did not show that it has formal policies and procedures to support the practice of refunding security deposits where it should not have been charged.

Q. Do you have any recommendations?

A. Yes, the Company should continue its practices of (1) verifying income levels and number of household members before requiring a security deposit, and (2) refunding security deposits that should not have been charged. The Company should show in rebuttal that it has formal policies and procedures in place addressing these practices and

[14] Valley response to OCA-VI-8.
[15] Valley response to OCA-VI-10.

that their employees are trained in them. If not, the Company should develop and implement formal policies or procedures to formalize these practices and ensure that employees are trained in them.

Q. Do you have any further recommendations?

A. Yes, the Company should permit the customer to decide whether they want to receive the returned security deposit as a refund or credit to their utility account balance.

Q. Why is your further recommendation reasonable?

A. Any security deposit that was unfairly assessed constitutes funds that rightfully belong to the customer. As such, the customer should retain the sole discretion over how those funds are utilized. For individuals living in poverty, financial management is often a day-to-day challenge. Allowing customers to have access to their own money provides them with greater autonomy and flexibility to address their most pressing needs. This approach may be more beneficial to the customer than applying the funds as credit to a future utility bill, which may not align with their immediate financial needs.

Payment Plans

Q. Does the Company offer payment plans?

A. Yes, the Company currently offers payment plans based on income levels using Federal Poverty Income (FPI) guidelines to determine the length of time to pay.[16]

Q. How does the Company establish payment arrangements?

A. The customer is asked to provide monthly household income and total number of household members. The Company then uses the FPI charts to determine the length of

[16] Valley response to OCA-VI-17.

time a customer is given to pay.[17] Payment history and past due balances are also considered in estimating a payment arrangement agreement.

Q. Does the Company track the success of their payment arrangements?

A. No, the Company currently does not track the effectiveness of their payment arrangements in terms of qualifying customers entering into them, customers being able to pay the amounts owed under the terms of the arrangements, and customers' ability to maintain service. The Company merely states that it manually monitors the plans for a customer's compliance with the payment terms of the payment arrangement and notifies the customer by telephone or letter of their upcoming payment.[18]

Q. Do you have any concerns about the Company not collecting data on the success of its payment arrangements?

A. Offering payment plans represents an effort to tailor payment obligations that are in line with a customer's financial means and promote fair and continued access to utility services. However, without performance metrics or ongoing analysis, it is difficult to determine whether these plans are achieving their intended goals, such as improving customer repayment rates or reducing delinquencies. In my professional opinion, the absence of such oversight may reflect a lack of due diligence and raise concerns about the company's ability to manage financial risk or make informed decisions regarding customer repayment strategies. In addition, as stated previously, the Company currently tracks plans manually. Manual tracking can lead to human error, omissions, and inconsistencies in record keeping.

[17] Id.
[18] Valley response to OCA-VI-19.

Q. Do you have any recommendations?

A. Yes, I recommend the Company establish metrics for measuring the success of payment plans and set documented plan policies, including how the FPI ranges are used, what verification is needed for low-income verification, and how payments and terms are calculated. The Company should also make sure payment options are clearly communicated to customers through all mean of communication used. In addition, I would also recommend the Company maintain internal controls on the number of payment plans offered, customers enrolled, and successful completion of said payments agreements. The Company should also consider separating plans by income levels. The Company should routinely evaluate its payment arrangements to identify the factors that contribute to the success or failure of the agreements and take steps to internalize the results of that analysis in its implementation of payment arrangements and communications with customers.

Q. Does this conclude your testimony.

A. Yes.

Qualifications of LeeAnn Wise, Senior Regulatory Analyst

Education:

- 2008, Master of Business Administration, Shippensburg University
- 1989, Bachelor of Science, Professional Accountancy, The Pennsylvania State University

Experience:

- January 2025 to Present, Senior Regulatory Analyst, Pennsylvania Office of Consumer Advocate
- January 2021 to January 2024, Senior Manager Finance & Accounting, COMCAST Corporation – Business Services
- January 2008 to January 2021, Manager Finance & Accounting, COMCAST Corporation
- May 1989 to March 2008, Senior Accountant, Penn Credit Corporation

Current Role Description:

I am currently employed by the Pennsylvania Office of Consumer Advocate (OCA) as a Senior Regulatory Analyst. In this position, my responsibilities include reviewing utility company filings with the Pennsylvania Public Utility Commission (Commission) and analyzing the financial, economic, accounting, rate of return, customer service, quality of service, and other technical or policy issues that are relevant to the filings. Additionally, I am tasked with preparing recommendations for the OCA's involvement in utility filings before the Commission, presenting written and oral testimony on behalf of the OCA.

Relevant Training and Experience:

I have over fifteen years of experience overseeing and evaluating planning and analysis for a $40 million customer call center operations, overseeing budgeting, forecasting, and variance analysis to improve financial accuracy and support strategic decision-making by senior leadership. This includes my employment at Comcast Corporation as a Manager and Senior Manager in Finance & Accounting, where I provided oversight of performance metrics, evaluating disputes and time to resolve, call-handle times, average speed of answer, and ensuring customer interactions align with policy standards. My training includes a sound understanding of the best practices in customer service delivery, call tracking protocols, and the importance of consistent documentation to support customer communication and reliability.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No. R-2025-3054393
	:	
Valley Energy, Inc.	:	
	:	

VERIFICATION

I, LeeAnn Wise, hereby state that the facts above set forth in my Direct Testimony, OCA Statement No. 4, are true and correct to the best of my knowledge, information, and belief and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa.C.S. § 4904 (relating to unsworn falsification to authorities).

DATED: July 15, 2025

Signature: /s/ LeeAnn Wise
LeeAnn Wise

Address: Office of Consumer Advocate
555 Walnut Street
Forum Place, 5th Floor
Harrisburg, PA 17101

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	Docket No.: R-2025-3054392
v.	:	
	:	
Wellsboro Electric Co.	:	

DIRECT TESTIMONY

OF

LeeAnn Wise

On behalf of the

PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

Date Served: July 15, 2025

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Introduction

Q. Please state your name and business address.

A. My name is LeeAnn Wise. My business address is 555 Walnut Street, Forum Place 5th Floor, Harrisburg, Pennsylvania 17101.

Q. By whom are you employed and in what capacity?

A. I am employed as a Regulatory Analyst by the Pennsylvania Office of Consumer Advocate (OCA).

Q. Please describe your educational background and qualifications to provide testimony in this case.

A. I have a Master's Degree in Business Administration from Shippensburg University and a Bachelor of Science degree in Professional Accountancy from the University of Pennsylvania. I have over fifteen years of experience in call center operations, with a strong background managing teams, improving workflow, and delivering outstanding customer service. Additionally, I have received internal training while working for the OCA. See Appendix A for additional information about my qualifications.

Q. What is the purpose of your testimony in this case?

A. I am filing the Direct Testimony in response to the application filed on April 30, 2025, by Wellsboro Electric (Wellsboro or Company) to increase its base rate for electricity services. The purpose of my testimony in this case is to address specific concerns regarding processing fees of $3.95 assessed to debit and credit card payments, how and when a security deposit is required, and the current payment arrangements available to customers.

Q. Have you previously provided testimony before the Pennsylvania Public Utility Commission?

A. No, I have not submitted testimony before the Pennsylvania Public Utility Commission.

Q. Have you prepared Exhibits to accompany your testimony?

A. No.

Summary

Q. Please describe the proposal for a rate increase filed by Wellsboro Electric Co.

A. Wellsboro proposes to increase its electric distribution revenue by $2.9 million per year, or about a 45.3% increase to annual distribution revenue, with a proposed effective date of June 29, 2025. Based on this filing, residential customers are facing monthly bill increases in distribution rates of up to nearly 49.4%.[1] More specifically, if approved as filed, residential customers using 700 kWh per month would see increases to their monthly bills by 49.4% on a distribution rate-only basis, including the fixed customer charge and volumetric distribution rates. The Company noticed customers that they would see a monthly bill increase of 18.4%, on a total rate basis, including commodity charges; however, the commodity charges are not at issue in this proceeding. Wellsboro's last rate increase was in April 2020 and was the result of a rate proceeding that settled for an annual revenue increase of $950,243.[2]

Q. Please summarize your conclusions and recommendations.

A. First, I recommend eliminating the payment fee imposed on customers paying their bills via credit or debit card through the Company's web-based and mobile application, known as SmartHub, which allows customers to view billing statements, monitor energy usage,

[1] Wellsboro Electric Exhibit (HSG-1) Schedule B8-1 pg.1. ln.7.
[2] PUC Opinion and Order Wellsboro R-2019-3008208 pg. 1.

and make payments electronically. While SmartHub offers convenience and promotes energy monitoring and conservation, the implementation and associated fee structure raises serious concerns. The Company imposes a fee of $3.95 on customers paying their bills via credit or debit card. Today, where electronic and paperless transactions are the norm, assessing an additional fee is contrary to the principles of fair utility service.

Next, as to screening for low-income customers when assessing security deposits, I recommend that the Company establish a practice of verifying income levels prior to charging a security deposit and develop and implement formal policies and procedures to formalize these practices and ensure that employees are trained in them. Additionally, the Company should show in rebuttal that it has formal policies and procedures in place to support its practice of refunding security deposits that should not have been charged to low-income customers, including methods of screening and timelines to refund any unneeded security deposits. If the Company does not have such formal policies and procedures, it should develop and implement formal policies or procedures to formalize these practices and ensure that employees are trained in them. I further recommend that the Company permit the customer to decide whether they want to receive the returned security deposit as a refund or credit to their utility account balance.

Finally, I recommend several improvements to ensure the success of customer payment arrangements.

Customer Payment Fees

Q. What is SmartHub?

A. SmartHub is a web and mobile application administered primarily by the Company with support provided as needed by the software vendor and C&T IT.[3] Customers can use SmartHub to pay bills and are assessed a $3.95 fee, view usage, and billing statements.[4]

Q. What are the key functions of the SmartHub application?

A. Wellsboro implemented the SmartHub platform for customers to view their bills, monitor usage data, and process payments electronically. The adoption of technology provides a user-friendly method for customers to access their account using a mobile app or online. Many of the Companies' customers have opted to utilize SmartHub to view their account. The tool is helpful in providing customers with a view at their usage trends, which allows for better management of energy consumption.

Q. Should the Company continue using SmartHub?

A. Yes, the use of web-based and online applications is highly effective in providing customers with real-time access to their account information. It is my recommendation that the Company continue its utilization of the SmartHub platform and explore the implementation of additional technological enhancements such as alerts for unusually high usage, real-time notifications of outages, and estimated charges based on month-to-date usage, to further improve the quality and efficiency of customer service.

[3] Wellsboro response to OCA-VI-5.
[4] Wellsboro response to OCA VI-1.

Q. Does Wellsboro Electric charge customers a processing fee for electronic payments?

A. Yes, the company charges a $3.95 fee when a customer pays using SmartHub or via telephone.[5]

Q. Why does the company charge this $3.95 fee?

A. Yes, The Company charges $3.95 fee to recover costs incurred from the third-party vendor for processing electronic payments.[6]

Q. How much revenue does the Company earn from charging the $3.95 payment fee?

A. In 2024, the amount collected from customers and remitted to the third-party vendor was $35,028.60, with the past three-year average of $32,717.[7] The fees are passed directly onto the third-party vendor. Therefore, there would be no revenue earned by Wellsboro Electric.[8]

Q. If the payment fee was eliminated, how much revenue would be forgone by the Company?

A. The $3.95 fee assessed to customers is passed directly onto the third-party vendor. If the Company were to eliminate the fee, it would not result in any revenue loss. However, the Company would claim the expense as a distribution cost for recovery through rates.

Q. Is the $3.95 processing fee reasonable?

A. No. The Company accepts checks, money orders, or bank transfers with no processing fees to consumers. A customer can also enroll in direct debit withdrawal from their bank account with no processing fees. However, a fee of $3.95 is assessed when paying using a debit or credit card through SmartHub. Although assessing fees for payments are not

[5] Wellsboro Electric response to OCA-III-3.
[6] Wellsboro Electric response to OCA-VI-1.
[7] Wellsboro Electric response to OCA-VI-3.
[8] Wellsboro Electric response to OCA-VI-4

prohibited by Chapter 56, the effect is to increase the rates for customers who pay by certain options that are normative in today's economy. While the Company does not benefit from these fees, customers are penalized by the imposed payment conditions, resulting in higher costs for customers choosing to use SmartHub or Interactive Voice Response (IVR) payment compared to other customers. The IVR system allows callers to interact with the company's phone system through voice prompts. The system uses pre-recorded information and routes customers to live agents. In my opinion, this policy is unreasonable and discriminates against those customers using credit and debit cards to pay for their service. The Company incurs administrative costs for processing cash and check payments, that are passed onto customers through the Company's rate base. Credit and debit charge payments should be handled in the same manner. Customers pay for household goods via credit and debit cards without being assessed an additional fee. Paying your utility bill should not be any different. The policy of charging a fee is quite harmful to lower income customers who may be unbanked and rely on pre-purchase debit cards to make payments.[9]

Q. Do you have any recommendations?

A. Yes. I recommend that the Company should be required to absorb the fee for SmartHub and IVR payment and the revenue requirements be adjusted accordingly. The costs for the third-party vendor are within the Company's control since they are negotiated contracts. The reasonable cost of offering a variety of payment methods without

[9] According to the 2023 FDIC National Survey of Unbanked and Underbanked Households, 5.9% of households were using general purchase reloadable prepaid cards and 49.7% of all households were using nonbank online payment services, such as PayPal, Venmo, and Cash App. The use of prepaid debit cards was much higher among unbanked households. Compared with banked households, substantially higher shares of unbanked households used online payment services and prepaid cards in ways that substitute for some of the core financial transactions that can be conducted using a bank account. - https://www.fdic.gov/household-survey/2023-fdic-national-survey-unbanked-and-underbanked-households-executive-summary.

additional customer fees should be reflected in the Company's revenue requirement, the same as the costs associated with processing checks and accepting payment in authorized locations.

Q. What are the benefits of your recommendations?

A. Providing a payment method through an application like SmartHub provides convenience for the Company and its customers and is considered good practice.[10] However, when a utility customer makes multiple payments during a month, fees on credit and debit payments undercut their ability to apply funds to the payment of actual utility services. Wellsboro should accept payment by any lawful means without additional fees and reflect reasonable and prudent costs to process these payments in its revenue requirement. This recommendation is in line with a growing trend among Pennsylvania utilities[11] to eliminate payment fees and reflects the expectation of most customers to use electronic payments without additional fees.

Q. Did you calculate the revenue adjustments needed if the payment processing fee of $3.95 was eliminated for customers?

A. No, I have not calculated the revenue adjustment. This calculation will be addressed by OCA witness Greg Meyer in his revenue requirement and accounting testimony. See OCA Statement No. 1.

[10] These and other reasons are discussed in NASUCA Resolution 2012-07. https://www.nasuca.org/2012-07-urgingutilities-to-eliminate-convenience-fees-for-paying-utility-bills-with-debit-and-credit-cards-and-urging-appropriatestate-regulatory oversight.

[11] In the last several years Pittsburgh Water and Sewer Authority, York Water, and Pennsylvania American Water have eliminated credit card and debit card payment fees.

Security Deposits

Q. Does the Company charge a security deposit?

A. Yes, The Company assesses a security deposit when the customer does not meet credit score requirements.

Q. Does the company screen to ensure low-income customers do not have to pay a security deposit?

A. No, the Company does not verify customer income levels prior to requiring a security deposit.[12] Additionally, the Company did not show that it has formal policies and procedures to support the practice of verifying income prior to charging a security deposit.

Q. Do you have any comments?

A. Yes, not having a practice or policy to screen customers for low-income presents a hardship on these customers, many of whom do not have the means to make a security deposit.

Q. Does the Company refund customers who have paid a security deposit and should not have?

A. Yes, security deposits are refunded when the customer has provided verified low-income documentation.[13] However, the Company did not say how the security deposit is returned (either as a refund or applied to the account balance) and it did not show that it has formal policies and procedures to support the practice of refunding security deposits where it should not have been charged.

Q. Do you have any recommendations?

[12] Wellsboro Electric response to OCA-VI-8.
[13] Wellsboro Electric response to OCA-VI-10.

A. Yes, the Company should establish a practice of verifying income levels prior to charging a security deposit and develop and implement formal policies and procedures to formalize these practices and ensure that employees are trained in them. Additionally, the Company should show in rebuttal that it has formal policies and procedures in place to support its practice of refunding security deposits that should not have been charged to low-income customers, including methods of screening and timelines to refund any unneeded surety deposits. If the Company does not have such formal policies and procedures, it should develop and implement formal policies or procedures to formalize these practices and ensure that employees are trained in them.

Q. Do you have any further recommendations?

A. Yes, the Company should permit the customer to decide whether they want to receive the returned security deposit as a refund or credit to their utility account balance.

Q. Why is your further recommendation reasonable?

A. Any security deposit that was unfairly assessed constitutes funds that rightfully belong to the customer. As such, the customer should retain the sole discretion over how those funds are utilized. For individuals living in poverty, financial management is often a day-to-day challenge. Allowing customers to have access to their own money provides them with greater autonomy and flexibility to address their most pressing needs. This approach may be more beneficial to the customer than applying the funds as credit to a future utility bill, which may not align with their immediate financial needs.

Payment Plans

Q. Does the Company offer payment plans?

A. Yes, the Company currently offers payment plans based on income levels using the Federal Poverty Income chart to determine the length of time to pay.

Q. How does the Company establish payment arrangements?

A. The payment arrangement is determined by the unpaid balance, the customer's ability to pay, the customer's payment history, income level, and the length of time the bill accumulated. Special consideration may be given if the customer has experienced a change in circumstance. All arrangements are based on the customer's average monthly bill combined with a portion of their outstanding balance according to their income level. Customers at or below 150% FPIG, are eligible for a payment arrangement of their twelve-month average plus $15.00 to be applied toward the arrears. Payment period for customers whose income is higher than 150% FPIG is calculated based on the following:

- 36 months for income 150% or below 250%
- 12 months for income at 250% or below 300%
- 6 months for income exceeding 300% FPIG or higher [14]

Q. Does the Company track how successful its payment arrangements are in recovering payment, customer retention, and reducing late payments?

A. No, the Company does not currently track the success of their payment arrangements[15] in terms of qualifying customers entering into them, customers being able to pay the amounts owed under the terms of the arrangements, and customers' ability to maintain service.

[14] Wellsboro Electric response to OCA-VI-16.
[15] Wellsboro Electric response to OCA-VI-19.

Q. Do you have any concerns about the Company not collecting data on the effectiveness of its payment arrangements?

A. Yes, offering payment plans represents an effort to tailor payment obligations in line with a customer's financial means, and promotes fair and continued access to utility services. However, without performance metrics or ongoing analysis, it is difficult to determine whether these plans are achieving their intended goals, such as improving customer repayment rates or reducing delinquencies. In my professional opinion, the absence of such oversight may reflect a lack of due diligence and raise concerns about the company's ability to manage financial risk or make informed decisions regarding customer repayment strategies.

Q. Do you have any recommendations?

A. Yes, I recommend the Company establish metrics for measuring the success of payment plans and set documented plan policies, including how the Federal Poverty Income ranges are used, what verification is needed for low-income verification, and how payments and terms are calculated. The Company should also make sure payment options are clearly communicated to customers through all means of communication used, especially to low-income customers. In addition, I would also recommend the Company maintain internal controls on the number of payment plans offered, customers enrolled, and successful completion of said payments agreements. The Company should also consider separating plans by income levels. The Company should routinely evaluate its payment arrangements to identify the factors that contribute to the success or failure of the agreements and take steps to internalize the results of that analysis in its implementation of payment arrangements and communications with customers.

Q. Does this conclude your testimony.

A. Yes.

Qualifications of LeeAnn Wise, Senior Regulatory Analyst

Education:

- 2008, Master of Business Administration, Shippensburg University
- 1989, Bachelor of Science, Professional Accountancy, The Pennsylvania State University

Experience:

- January 2025 to Present, Senior Regulatory Analyst, Pennsylvania Office of Consumer Advocate
- January 2021 to January 2024, Senior Manager Finance & Accounting, COMCAST Corporation – Business Services
- January 2008 to January 2021, Manager Finance & Accounting, COMCAST Corporation
- May 1989 to March 2008, Senior Accountant, Penn Credit Corporation

Current Role Description:

I am currently employed by the Pennsylvania Office of Consumer Advocate (OCA) as a Senior Regulatory Analyst. In this position, my responsibilities include reviewing utility company filings with the Pennsylvania Public Utility Commission (Commission) and analyzing the financial, economic, accounting, rate of return, customer service, quality of service, and other technical or policy issues that are relevant to the filings. Additionally, I am tasked with preparing recommendations for the OCA's involvement in utility filings before the Commission, presenting written and oral testimony on behalf of the OCA.

Relevant Training and Experience:

I have over fifteen years of experience overseeing and evaluating planning and analysis for a $40 million customer call center operations, overseeing budgeting, forecasting, and variance analysis to improve financial accuracy and support strategic decision-making by senior leadership. This includes my employment at Comcast Corporation as a Manager and Senior Manager in Finance & Accounting, where I provided oversight of performance metrics, evaluating disputes and time to resolve, call-handle times, average speed of answer, and ensuring customer interactions align with policy standards. My training includes a sound understanding of the best practices in customer service delivery, call tracking protocols, and the importance of consistent documentation to support customer communication and reliability.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No. R-2025-3054392
	:	
Wellsboro Electric Company	:	

VERIFICATION

I, LeeAnn Wise, hereby state that the facts above set forth in my Direct Testimony, OCA Statement No. 4, are true and correct to the best of my knowledge, information, and belief and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa.C.S. § 4904 (relating to unsworn falsification to authorities).

DATED: July 15, 2025

Signature: */s/ LeeAnn Wise*
LeeAnn Wise

Address: Office of Consumer Advocate
555 Walnut Street
Harrisburg, PA 17101

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
v.	)	**R-2025-3054394**
Citizens' Electric Company of Lewisburg, PA	)	

Rebuttal Testimony and Exhibit of

Greg R. Meyer

OCA Statement 1R

On behalf of

Pennsylvania Office of Consumer Advocate

Date Served: August 13, 2025

BRUBAKER & ASSOCIATES, INC.

Project 11858

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
v.	)	**R-2025-3054394**
Citizens' Electric Company of Lewisburg, PA	)	

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EXHIBIT GRM-R1 (CITIZENS)

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
v.	)	**R-2025-3054394**
Citizens' Electric Company of Lewisburg, PA	)	

Rebuttal Testimony of Greg R. Meyer

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Greg R. Meyer. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q WHAT IS YOUR OCCUPATION?

A I am a consultant in the field of public utility regulation and a Senior Principal with the firm of Brubaker & Associates, Inc. ("BAI"), energy, economic and regulatory consultants.

Q ARE YOU THE SAME GREG R. MEYER WHO PREVIOUSLY FILED DIRECT TESTIMONY ON JULY 15, 2025, IN THIS PROCEEDING?

A Yes, I am.

Q ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?

A I am appearing on behalf of the Pennsylvania Office of Consumer Advocate ("OCA").

Q PLEASE GIVE A BRIEF OVERVIEW OF YOUR REBUTTAL TESTIMONY.

A My Rebuttal Testimony will address certain issues that the OCA would support and the revenue requirement impact from those issues. I am not addressing all issues of agreement due to the value of the issues, but the OCA will support those adjustments in either settlement negotiations or at the rate case hearings.

My silence regarding any issue should not be construed as an endorsement of or acquiescence to positions advanced by Citizens' Electric Company of Lewisburg, PA ("Citizens").

Q WHAT ADJUSTMENTS WILL YOU BE DISCUSSING IN YOUR REBUTTAL TESTIMONY?

A My Rebuttal Testimony will address the following issues:

- The adoption of Citizens' agreed to updates.
- The adoption of the 2026 state income tax rate of 7.49%.
- The normalization versus amortization of rate case expense and rate base treatment.

Q HAVE YOU PREPARED EXHIBIT GRM-R1 (CITIZENS) TO SHOW THE IMPACTS OF THESE TWO ISSUES ON THE OCA'S PROPOSED REVENUE REQUIREMENT?

A Yes. I have prepared Exhibit GRM-R1 (Citizens) that shows the revenue requirement impact from the issues that the OCA is supporting.

Table GRM-R1 (Citizens)

OCA Revenue Requirement Adjustments

Line	Description	Amount
1	Company Proposed Revenue Requirement Increase[1]	$ 1,794,525
	OCA Adjustments:	
2	Return on Equity	$ (268,215)
3	Rate Revenue	$ (56,136)
4	Uncollectible Expense	$ (5,111)
5	Labor	$ (125,320)
6	Acct 593 and 920	$ (272,331)
7	Sponsorship and Lobbying	$ (2,109)
8	Credit Card Fee	$ 43,014
9	Income Tax Rate	$ (35,038)
10	Rate Case Expense	$ (8,919)
11	Rate Case Reg Liability	$ (26,475)
12	Office Supplies	$ (110,852)
13	Total OCA Adjustments	$ (867,492)
14	OCA Proposed Revenue Requirement Increase	$ 927,033

Source:
[1]OCA-I-1 Attachment A (Schedule A-D) Tab "C1."

CITIZENS' UPDATES

Q HAS CITIZENS IDENTIFIED ANY ISSUES THAT THEY PROPOSE TO UPDATE THAT WOULD LOWER ITS REQUESTED REVENUE REQUIREMENT?

A Yes, according to the Bureau of Investigation and Enforcement ("I&E") witness Zachari Walker, Citizens has proposed to update its revenue requirement to reflect

adjustments to rate case expense and generation supply costs that were erroneously included in office supplies and expenses. The rate case adjustment reduces expense by $8,298 and the office supplies adjustment reduces expense by $103,132.[1] Both of these adjustments are reflected in my Exhibit GRM-R1 (Citizens).

INCOME TAX RATE

Q HAVE YOU READ THE DIRECT TESTIMONY OF THE OFFICE OF SMALL BUSINESS ADVOCATE ("OSBA") WITNESS JUSTIN FARR AND I&E WITNESS ZACHARI WALKER ADDRESSING THE STATE INCOME TAX RATE?

A Yes, I have.

Q WHAT DO THESE WITNESSES PROPOSE TO USE FOR THE STATE INCOME TAX RATE?

A Both witnesses propose to use the state income tax rate of 7.49% which will be in effect in 2026.[2] Both witnesses discuss that on July 8, 2022, Pennsylvania House Bill 1342 was signed into law as Act 53 of 2022. Act 53 lowered the state corporate income tax rate over several years to a 4.99% state corporate tax rate effective in 2031.

[1]Walker Direct Testimony (Citizens), I&E Statement 1, pages 13-16.
[2]Walker Direct Testimony (Citizens), I&E Statement 1, page 25.

Q DO YOU SUPPORT THIS POSITION?

A Yes, the 2026 state corporate tax rate of 7.49% should be used to calculate Citizens' revenue requirement. I have incorporated the 2026 state corporate tax rate (7.49%) in my revenue requirement calculation and reflected the impact on my Exhibit GRM-R1 (Citizens). The new corporate tax rate lowers Citizens' revenue requirement by $35,038. I would also note that this adjustment includes the reduction in the cash working capital balance required for this revenue requirement issue.

NORMALIZATION OF RATE CASE EXPENSES

Q HAVE YOU READ THE REBUTTAL TESTIMONY OF I&E WITNESS ZACHARI WALKER DISCUSSING RATE CASE EXPENSE?

A Yes, I have.

Q PLEASE SUMMARIZE MR. WALKER'S POSITION.

A Mr. Walker supports normalizing rate case expense over the projected period of time that will occur between Citizens' rate cases. Mr. Walker argues correctly that rate case expense should be normalized instead of establishing an amortization period. Mr. Walker also recognizes that rate case expense is an operating expense that is incurred periodically. Normalizing this expense for equal recovery over a multi-year period is the proper ratemaking principle. I support normalizing rate case expense. I support Citizens' and Mr. Walker's three-year rate case interval for normalizing rate case expense.[3]

[3]Walker Direct Testimony (Citizens), I&E Statement 1, page 9.

Q WHAT RATEMAKING TREATMENT DID CITIZENS PROPOSE?

A According to Mr. Walker, Citizens proposed to amortize rate case expense over a multi-year period. Given that Citizens chose to amortize rate case expense, it also is requesting rate base treatment for the unamortized rate case expense balance.

Q ARE YOU SUPPORTIVE OF INCLUDING THE UNAMORTIZED PORTION OF RATE CASE EXPENSE IN CITIZENS' RATE BASE?

A Absolutely not. Rate case expense is a normal operating expense of the utility. Normalizing the rate case expense recovery over a multi-year period is the proper method to collect these recurring, but not annual expenses. By including rate case expense in rate base, Citizens' shareholders would earn a profit on a normal and recuring expense item. I am opposed to enhancing the profits of Citizens' shareholders for the inclusion of rate case expense in rate base. Furthermore, rate cases also provide benefits for Citizens' shareholders. There is no need to reward shareholders further by allowing a profit return on those expenses.

Q WHAT IS THE REVENUE REQUIREMENT IMPACT FOR DISALLOWING RATE BASE TREATMENT OF RATE CASE EXPENSE?

A Removing the unamortized balance of rate case expense from Citizens' rate base would lower Citizens' revenue requirement by $26,475.

CONCLUSION

Q DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A Yes, it does.

Table GRM-R1 (Citizens)

OCA Revenue Requirement Adjustments

Line	Description	Amount
1	Company Proposed Revenue Requirement Increase[1]	$ 1,794,525
	OCA Adjustments:	
2	Return on Equity	$ (268,215)
3	Rate Revenue	$ (56,136)
4	Uncollectible Expense	$ (5,111)
5	Labor	$ (125,320)
6	Acct 593 and 920	$ (272,331)
7	Sponsorship and Lobbying	$ (2,109)
8	Credit Card Fee	$ 43,014
9	Income Tax Rate	$ (35,038)
10	Rate Case Expense	$ (8,919)
11	Rate Case Reg Liability	$ (26,475)
12	Office Supplies	$ (110,852)
13	Total OCA Adjustments	$ (867,492)
14	OCA Proposed Revenue Requirement Increase	$ 927,033

Source:
[1]OCA-I-1 Attachment A (Schedule A-D) Tab "C1."

Citizens' Electric Company of Lewisburg

Change Log of OCA Adjustments to Revenue Requirement

Line	Issue	Changed Cells	Starting Revenue Requirement Increase	Ending Revenue Requirement Increase	OCA Adjustment	Notes and Sources
			(1)	(2)	(3)	(4)
1	Return on Equity	Changed Cell E11 on Tab "C1-2" to 9.5%	$ 1,794,525	$ 1,526,309	$ (268,215)	See Mr. Christopher Walters, OCA Statement 2
2	Rate Revenue - Residential	Added 785,507 to Cell D7 on Tab "B3-1"	$ 1,526,309	$ 1,499,735	$ (26,574)	See Mr. Greg Meyer, OCA Statement 1; See Adjustment Schedule 1 for the calculation of additional usage added
3	Rate Revenue - Commercial	Added 2,129,464 to Cell F7 and 14,213 to Cell E7 on Tab "B3-1"	$ 1,499,735	$ 1,478,507	$ (21,228)	See Mr. Greg Meyer, OCA Statement 1; See Adjustment Schedule 1 for the calculation of additional usage added
4	Rate Revenue - Industrial	Added 8,054,804 to Cell G7 on Tab "B3-1"	$ 1,478,507	$ 1,470,174	$ (8,333)	See Mr. Greg Meyer, OCA Statement 1; See Adjustment Schedule 1 for the calculation of additional usage added
5	Uncollectible Expense	Changed Cell I34 on Tab "C1-1" to $26,091	$ 1,470,174	$ 1,465,063	$ (5,111)	See Mr. Greg Meyer, OCA Statement 1; See Adjustment Schedule 1 for the calculation of $26,091
6	Labor	On Tab "WP1_C", changed all Cells with values in Column L from Account 580 to Account 932.4 to reflect a 4% increase in total labor for each year from 2024 in relation to their proportion of expense to the total in Line 53.	$ 1,465,063	$ 1,339,743	$ (125,320)	See Mr. Greg Meyer, OCA Statement 1
7	Account 593	On Tab "WP1_C", changed the non-labor 2026 Accounts 593, 593.5, 593.6 to total $468,197 by using their company proposed proportion multiplied by $468,197.	$ 1,339,743	$ 1,133,787	$ (205,956)	See Mr. Greg Meyer, OCA Statement 1
8	Account 920	Changed Cell Q43 on Tab "WP1_C" to equal $404,145	$ 1,133,787	$ 1,067,412	$ (66,375)	See Mr. Greg Meyer, OCA Statement 1
9	Sponsorship and Lobbying	Subtracted $695 from Cell G55 and $1,267 from Cell G56 on Tab "WP1_C"	$ 1,067,412	$ 1,065,302	$ (2,109)	See Mr. Greg Meyer, OCA Statement 1
10	Credit Card Fee	Added $40,010 to Cell G39 on Tab "WP1_C"	$ 1,065,302	$ 1,108,317	$ 43,014	See Ms. LeeAnn Wise, OCA Statement 4
11	Income Tax Rate	Changed Cell C26 on Tab "C1-4" to 7.49%	$ 1,108,317	$ 1,073,278	$ (35,038)	See https://www.pa.gov/agencies/revenue/resources/tax-rates/corporation-tax-rates for 2026 Tax Rate of 7.49%
12	Rate Case Expense	Removed $8,298 from Cell G33 on Tab "C1-3"	$ 1,073,278	$ 1,064,359	$ (8,919)	See Mr. Greg Meyer, OCA Statement 1-R
13	Supplies Expenses	On Tab "WP1_C", subtracted $103,132 from the four 921 accounts based on the company proposed proportion of each account to the total account 921.	$ 1,064,359	$ 953,508	$ (110,852)	See Mr. Greg Meyer, OCA Statement 1-R
14	Rate Case Reg Liability	Removed Values from Cells F54 to G54 on Tab "C1-5"	$ 953,508	$ 927,033	$ (26,475)	See Mr. Greg Meyer, OCA Statement 1-R
14				OCA Total Adjustments	$ (867,492)	

Citizens' Electric Company of Lewisburg

Residential Usage per Customer Adjustments

Line	Description	Residential
1	Company Proposed FPFTY Sales (kWh)[1]	87,664,162
2	Company Proposed FPFTY Average Customers[1]	6,051
3	Company Proposed Usage per Customer (Line 1 ÷ Line 2)	14,488
4	OCA Proposed Usage per Customer[2]	14,617
5	OCA Adjustment to Usage per Customer (Line 4 - Line 3)	130
6	OCA Proposed Additional Usage (Line 2 x Line 5)	785,507

Commerical Usage per Customer Adjustments

Line	Description	GLP-1	SH	Total
		(1)	(2)	(3)
7	Company Proposed FPFTY Sales (kWh)[1]	27,208,762	181,607	27,390,368
8	Company Proposed FPFTY Average Customers[1]	1,137	3	1,140
9	Company Proposed Usage per Customer (Line 7 ÷ Line 8)			24,027
10	OCA Proposed Usage per Customer[2]			25,907
11	OCA Adjustment to Usage per Customer (Line 10 - Line 9)			1,880
12	OCA Proposed Additional Usage[3]	2,129,464	14,213	2,143,678

Industrial Usage per Customer Adjustments

Line	Description	GLP-3
13	Company Proposed FPFTY Sales (kWh)[1]	46,600,138
14	Company Proposed FPFTY Average Customers[1]	42
15	Company Proposed Usage per Customer (Line 13 ÷ Line 14)	1,109,527
16	OCA Proposed Usage per Customer[2]	1,301,308
17	OCA Adjustment to Usage per Customer (Line 16 - Line 15)	191,781
18	OCA Proposed Additional Usage (Line 14 x Line 17)	8,054,804

Sources and Notes:

[1]Company Schedule B3-1.

[2]Ten year average of sales divided by average customers from 2020 to 2024 Annual Reports.

[3]Total is Line 8 x Line 11 while the different rate classes are calculated based on a proportion of their usage in Line 7 to the total

Citizens'

Net Write-offs

Year	Revenues	Net Write-offs	% of Rev	
2,020	$ 13,603,836	$ 18,770	0.138%	*Revenues sourced from Annual Reports
2,021	$ 13,692,112	$ 18,429	0.135%	*Net Write Offs from OCA DR 7-17
2,022	$ 16,929,825	$ 20,270	0.120%	
2,023	$ 20,304,827	$ 31,823	0.157%	
2,024	$ 16,279,186	$ 24,932	0.153%	
Total	$ 80,809,786	$ 114,225	0.141%	
HTY	$ 16,378,412	$ 27,330	0.167%	*Uncollectibles Sourced from Company Schedule C1-1
FTY	$ 16,644,983	$ 30,000	0.180%	*Revenues sources from Company Schedule C1
FPFTY Present	$ 16,663,825	$ 30,900	0.185%	
FPFTY Proposed	$ 18,458,350	$ 30,900	0.167%	
	OCA Proposed	$ 26,091	0.141%	

B3-1

Citizens' Electric Company of Lewisburg
Rate Case with Fully Projected Future Test Year 2026
Billing Units, Rates And Revenue At Present Rates
Fully Projected Future Test Year 2026

		Residential	Space Heating	GLP-1	GLP-3	Municipal Boulevard	Outdoor Lighting	Total
1				**BILLING UNITS**				
2	kWh Sales	88,449,669	195,820	29,338,226	54,654,942	75,543	213,869	172,928,069
3								
4	Number of Bills	72,612	36	13,644	504	156	312	87,264
5	Average Monthly Bills	6,051	3	1,137	42	13	26	7,272
6								
7				**Annual Billing Units- Public Lighting and Street Lighting HY 2024**				
8	Rate 1				MBL- Meter	13		
9	Rate 2				MBL- Post	535		
10	Rate 3				Monthly revenue	2,179	9,602	
11	Rate 4							
12				**RATES AND CHARGES**				
13				**Tariff Rates**				
14	Customer Charge	$13.10	$20.19	$16.00	$55.00	$3.84		
15						$3.98	Average	
16	Energy Block 1	$0.03368	$0.04413	$0.00963	$0.009490		$14.66	
17	Energy Block 2				$0.001030		Count	
18	Reservation Chge				$2.51		655	
19	Voltage Discount				($0.234420)			
20	Block 1 kWh = Demand X				30			
21	Demand Block 1			$3.74	$5.37			
22								
23				**COMPUTATION OF REVENUE**				
24	Customer Charge Revenue	951,217	727	218,304	27,720	26,151	115,224	1,339,343
25								
26	Distribution kWh Revenue	2,978,985	8,642	282,527	88,085			3,358,239
27	Distribution Demand Revenue	0	0	611,814	801,634			1,413,448
28	*Total Distribution Revenue*	2,978,985	8,642	894,341	889,720	0	0	4,771,687
29	**Total Distribution Revenue**	$3,930,202	$9,368	$1,112,645	$917,440	$26,151	$115,224	$6,111,030
30	*FTY 2025*	*3,887,618*	*8,741*	*1,092,138*	*908,267*	*26,151*	*115,224*	*6,038,139*
31								
32	Block 1 kWh 2024				3,757,740			
33	Block 2 kWh 2024				50,897,202			
34								
35	Demand kW 2024			163,587	131,225			
36	New Customers, Load Factor	29.4%			318			
37	Demand kW			163,587	131,543			295,130
38								
39	Reservation kW- annaul				150,600			150,600
40	Reservation (CR-kW)- annual				(41,529)			
41	Voltage Discount- kW				58,964			58,964
42	Block 1 kWh				3,500			3,500
43								
44	Customers December 2024	6,001	3	1,137	40	13	26	7,220
45	Customers added (lost) 2025	25	0	0	2	0	0	27
46	Customers added (lost) 2026	25						25
47	Forecast Customers 2026	6,051	3	1,137	42	13	26	7,247
48	Average Annual UPC, 2020-202	14,488	60,536	23,930	1,144,553			
49	Existing Customers	6,001	3	1,137	40	13	26	7,220
50	Forecast kWh 2026, Existing	86,939,784	181,607	27,208,762	45,782,138	75,543	213,869	160,401,703
51	Projected New Customers 2025	362,189			537,000			899,189
52	Projected New Customers 2026	362,189			281,000			643,189
53	Forecast kWh 2026	87,664,162	181,607	27,208,762	46,600,138	75,543	213,869	161,944,081
54								

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Citizens' Electric Company of Lewisburg
Rate Case with Fully Projected Future Test Year 2026

Net Operating Income And Rates of Return
HY 2024, FTY 2025 and FPFTY 2026
Answer to 52 Pa. Code 53.52 c[1]

Line	Description	Present Rates HY 12/31/2024		Present Rates FTY 12/31/2025	Present Rates FPFTY 12/31/2026	Full Revenue Requirement FPFTY 12/31/2026	Proposed Rates FPFTY 12/31/2026
		Per Books	Distribution Only	Distribution Only	Distribution Only	Distribution Only	Distribution Only
1	**REVENUE**						
2	Residential	$3,689,870	$3,689,870	$3,887,618	$3,930,202		$5,148,260
3	Comm and indus	1,981,976	1,981,976	2,009,146	2,039,453		2,507,965
4	Lighting	141,375	141,375	141,375	141,375		194,201
5	Rounding	0					
6	Electric operating revenue	5,813,222	5,813,222	6,038,139	6,111,030	7,038,063	7,850,427
7	Other revenue, net	99,224	99,224	102,026	104,137	104,137	104,137
8	GSSR	10,504,818					
9	Other, net	(38,851)	(38,851)				
10	Total Revenue	16,378,412	5,873,594	6,140,165	6,215,167	7,142,200	7,954,564
11	*Annual kWH*	*150,899,872*	*150,899,872*	*161,300,892*	*172,928,069*	*172,928,069*	*172,928,069*
12	**EXPENSES**				Increase	927,033	
13	Purchased electricity	10,504,818					
14	Distribution	1,556,654	1,556,654	1,743,703	1,684,968	1,684,968	1,684,968
15	Customer acct & coll	536,669	536,669	542,259	567,426	567,426	567,426
16	Admin & general	1,268,350	1,268,350	1,429,095	1,401,599	1,401,599	1,401,599
17	Total Operating expense	13,866,491	3,361,673	3,715,057	3,653,994	3,653,994	3,653,994
18							
19	Depreciation expense	1,126,159	1,126,159	1,323,181	1,409,998	1,409,998	1,409,998
20							
21	Taxes other than income	978,426	427,276	441,195	446,255	500,950	548,834
22							
23	Total Expenses	15,971,075	4,915,108	5,479,433	5,510,246	5,564,941	5,612,825
24							
25	Net operating income before income taxes	407,337	958,487	660,732	704,921	1,577,259	2,341,738
26							
27	Income tax expense	119,515	154,294	93,332	96,205	331,013	536,789
28	NET UTILITY OPERATING INCOME (LOSS) (A)	$287,822	$804,192	$567,400	$608,716	$1,246,246	$1,804,949
29							0.107754
30	RATE BASE (B)		$15,107,207	$15,902,897	$16,750,614	$16,750,614	$16,750,614
31	RATE OF RETURN ON RATE BASE (A / B)		5.32%	3.57%	3.63%	7.44%	10.78%

C1-1

Citizens' Electric Company of Lewisburg
Rate Case with Fully Projected Future Test Year 2026

Net Operating Income And Rates of Return
HY 2024, FTY 2025 and FPFTY 2026
Answer to 52 Pa. Code 53.52 c[1] - Support Sheet No. 1
Support Sheet No. 1- Operating Expense and Going-Level Adjustments

Line	Acct.	Account Description	Year 2023 Actual	Year 2024 Actual	Year 2024 to Year 2025 Changes	Year 2025 Forecast	Year 2025 to Year 2026 Changes	Year 2026 Forecast	Labor Year 2023 Actual	Labor HY 2024 Actual	Labor FTY 2025 Forecast	Labor FPFTY 2026 Forecast
1	Distribution Expenses											
2	580	Operations Supv & Eng	139,449	147,492	3,650	151,142	(3,197)	147,944	65,639	69,376	70,506	66,366
3	582	Station Expense	20,968	5,258	8,721	13,979	(500)	13,478	8,446	1,974	5,821	5,373
4	583	Overhead Line	242,610	226,033	8,894	234,927	(2,517)	232,410	106,207	80,793	99,056	91,436
5	585	Street Lighting	8,095	12,169	(7,144)	5,025	(102)	4,922	2,438	4,820	2,195	2,026
6	586	Meter Expense	25,262	24,042	24,916	48,958	(441)	48,517	18,234	(7,401)	22,504	20,773
7	587	Customer Installation	39,845	41,115	12,650	53,765	511	54,276	16,746	19,074	21,945	20,257
8	588	Miscellaneous Distribution	395,055	455,104	31,311	486,415	(3,565)	482,850	116,645	121,176	127,162	117,380
9	589	Rents	520	530	(5)	525	0	525	0	0	0	0
10		*Total Operating & Maintenanc*	871,804	911,743	82,992	994,735	(9,813)	984,922	334,356	289,812	349,187	323,611
11												
12	592	Maintenance of Station Equipmen	2,202	25,133	(8,301)	16,832	(350)	16,482	1,134	11,213	7,461	6,887
13	593	Maintenance of Overhead Lines	563,525	558,565	108,646	667,211	(47,914)	619,297	142,193	139,744	163,850	151,100
14	594	Maintenance of Underground Line	16,532	13,331	1,030	14,361	(135)	14,226	6,923	5,237	6,159	5,686
15	595	Maintain Line Transformers	85,912	31,968	(5,001)	26,967	(219)	26,748	9,440	7,462	7,377	6,809
16	596	Maint. Street Light & Signal	22,847	15,914	7,682	23,596	(304)	23,292	10,192	6,283	9,176	8,470
17	597	Maintenance of Misc. Distrib Plan	0	0	0	0	0	0	0	0	0	0
18		*Total Maintenance*	691,018	644,911	104,057	748,968	(48,922)	700,046	169,882	169,939	194,023	178,952
19		*Total Operating & Maintenanc*	1,562,822	1,556,654	187,049	1,743,703	(58,735)	1,684,968	504,238	459,751	543,210	502,563
20												
21	Customer Accounting & Collection Expenses:											
22	902	Meter Reading Expense	25,085	26,338	(338)	26,000	0	26,000	0	0	0	0
23	903	Customer Records & Collection	474,976	483,001	3,258	486,259	29,076	515,335	176,064	174,418	174,043	162,322
24	904	Uncollectible Accounts	31,906	27,330	2,670	30,000	(3,909)	26,091	0	0	0	0
25		*Total Customer Accting & Coll*	531,968	536,669	5,590	542,259	25,167	567,426	176,064	174,418	174,043	162,322
26												
27	Administrative & General Expenses:											
28	920	Administrative & General Salaries	742,994	700,832	31,998	732,830	50,327	783,157	351,801	323,420	341,855	379,012
29	921	Office Supplies & Expenses	243,492	145,653	101,335	246,988	(95,722)	151,265	0	0	0	0
30	923	Outside Services Employed	47,103	40,008	(3,008)	37,000	1,110	38,110	0	0	0	0
31	924	Property Insurance	11,431	11,190	(131)	11,059	0	11,059	0	0	0	0
32	925	Injuires & Damages	27,561	27,341	1,566	28,907	0	28,907	0	0	0	0
33	926	Employee Pensions & Benefits	6,204	7,497	1,003	8,500	255	8,755	0	0	0	0
34	928	Regulatory Commission	105,515	70,128	18,080	88,208	20,681	108,889	0	0	0	0
35	930	Miscellaneous General	105,300	110,600	291	110,891	1,365	112,256	0	0	0	0
36	932	Maintenance of General Property	121,914	155,101	9,612	164,713	(5,511)	159,201	47,569	62,272	64,116	59,184
37		*Total Administrative & General*	1,411,514	1,268,350	160,745	1,429,095	(27,496)	1,401,599	399,370	385,692	405,971	438,197
38												
39		**Total O&M Expense**	**$3,506,304**	**$3,361,673**	**$353,384**	**$3,715,057**	**($61,064)**	**$3,653,994**	**$1,079,671**	**$1,019,861**	**$1,123,224**	**$1,103,082**

Line			Year 2023	Year 2024	Year 2024 to Year 2025	Year 2025	Year 2025 to Year 2026	Year 2026
41								
42		Labor	1,079,671	1,019,861	103,363	1,123,224	(20,142)	1,103,082
43		Overhead	1,197,394	1,239,081	45,537	1,284,618	(44,373)	1,240,245
44		Transportation	101,038	87,328	1,310	88,638	13,682	102,320
45		Materials	1,128,201	1,015,403	203,174	1,218,577	59,663	1,278,240
46			3,506,304	3,361,673	353,384	3,715,057	8,829	3,723,887

C1-2

Citizens' Electric Company of Lewisburg
Rate Case with Fully Projected Future Test Year 2026
Net Operating Income And Rates of Return
Support Sheet No. 2- Cost of Capital and Fair Rate of Return Based upon Hypothetical Ratemaking Capital Structure
12/31/2025 and 12/31/2026

Line	Type of Capital		Ratios (1)	12/31/26 Cost Rate	12/31/26 Weighted Cost
1	Long-Term Debt	(B)	51.06%	5.470%	2.79%
2	Preferred Stock				
3	Common Equity	(A)	48.94%	9.50%	4.65%
4	Total		100.00%		7.44%
5				Using	7.44000%
6					
7	(A) Recommended hypothetical capital structure ratios as discussed in direct testimony.				

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Citizens' Electric Company of Lewisburg
Rate Case with Fully Projected Future Test Year 2026

Net Operating Income And Rates of Return
HY 2024, FTY 2025 and FPFTY 2026
Answer to 52 Pa. Code 53.52 c[1]
Support Sheet No. 3- Taxes Other Than Income

Line	Description		HY 2024		Present Rates FTY 12/31/2025	Present Rates FPFTY 12/31/2026	Full Revenue Requirement FPFTY 12/31/2026	Proposed Rates FPFTY 12/31/2026
			Per Books	Distribution Only	Distribution Only	Distribution Only		Distribution Only
1	Taxes other than income:							
2	Pennsylvania Use Tax		$7,604	$7,604	$7,604	$7,604	$7,604	$7,604
3	PUC Assessment		63,038	63,038	63,038	63,038	63,038	63,038
4	Public Utility Realty Tax (including surcharge)		13,654	13,654	14,302	15,062	15,062	15,062
5	Pennsylvania Gross Receipts Tax		894,130	342,980	356,250	360,551	415,246	463,130
6			$978,426	$427,276	$441,195	$446,255	$500,950	$548,834
7								
8	**Gross Receipts Tax**							
9	Distruibution revenue		$5,813,222	$5,813,222	$6,038,139	$6,111,030	$7,038,063	$7,849,668
10	GSSR, including over/under		10,504,818					
11	Gross Receipts Taxable		$16,318,039	$5,813,222	$6,038,139	$6,111,030	$7,038,063	$7,849,668
12	Gross Receipts Tax at Present Rate	5.90%	$962,764	$342,980	$356,250	$360,551	$415,246	$463,130
13	Prior Year adjustment		(68,634)					
14	Gross Receipts Tax expense		$894,130	$342,980	$356,250	$360,551	$415,246	$463,130
15								
16	**Normalized Rate case expense**							
17	Estimated expenses					$326,667		
18	Amortization period (years)					3.0		
19	Normalized Rate case expense					108,889		
20			12/31/2023	12/31/2024	12/31/2025			
21	Rate Case 2022		147,203	80,155	80,155		Amortized by 12/31/2025	
22	POLR/PJM 2021		25,614	7,533	7,533		Amortized by 12/31/2025	
23	POLR/PJM 2024			24,893	8,298			
24	Normalized Rate case expense		172,817	112,581	95,986	108,889		

C1-4

Citizens' Electric Company of Lewisburg
Rate Case with Fully Projected Future Test Year 2026

Net Operating Income And Rates of Return
HY 2024, FTY 2025 and FPFTY 2026
Answer to 52 Pa. Code 53.52 c[1]
Support Sheet No. 4- Income Tax Calculations

Line	Description	Rate	HY 2024		Present Rates FTY 12/31/2025	Present Rates FPFTY 12/31/2026	Full Revenue Requirement FPFTY 12/31/2026	Proposed Rates FPFTY 12/31/2026
			Per Books	Distribution Only	Distribution Only	Distribution Only	Distribution Only	Distribution Only
1	Net Operating Income Excluding Income Taxes		$407,337	$958,487	$660,732	$704,921	$1,577,259	$2,341,738
2								
3	Synchronized interest expense:							
4	Rate base		0	15,107,207	15,902,897	16,750,614	16,750,614	16,750,614
5								
6	Rate base for interest compuation		0	15,107,207	15,902,897	16,750,614	16,750,614	16,750,614
7	Weighted Cost of debt		2.793%	2.793%	2.793%	2.793%	2.793%	2.793%
8	Synchronized interest expense		0	421,941	444,165	467,841	467,841	467,841
9	Taxable income before depreciation tax adjustments		407,337	536,545	216,567	237,080	1,109,418	1,873,897
10								
11	Pennsylvania depreciation adjustment:							
12	Tax depreciation (using DDB method)		(1,255,863)	(1,255,863)	(1,277,811)	(1,399,256)	(1,399,256)	(1,399,256)
13	Book depreciation		1,126,159	1,126,159	1,323,181	1,409,998	1,409,998	1,409,998
14	Pennsylvania depreciation adjustment		(129,705)	(129,705)	45,370	10,742	10,742	10,742
15	Pennsylvania taxable income		277,632	406,841	261,938	247,821	1,120,159	1,884,639
16	Regulatory Pennsylvania income tax expense	7.49%	20,795	30,472	19,619	18,562	83,900	141,159
17								
18	Federal depreciation adjustment:							
19	Tax depreciation (using SL method with bonus depreciatio		(1,042,603)	(1,042,603)	(1,169,116)	(1,258,785)	(1,258,785)	(1,258,785)
20	Book depreciation		1,126,159	1,126,159	1,323,181	1,409,998	1,409,998	1,409,998
21	Federal depreciation adjustment		83,555	83,555	154,065	151,212	151,212	151,212
22								
23	Taxable income before depreciation tax adjustments		407,337	536,545	216,567	237,080	1,109,418	1,873,897
24	Federal depreciation adjustment		83,555	83,555	154,065	151,212	151,212	151,212
25	Pennsylvania income tax expense		(20,795)	(30,472)	(19,619)	(18,562)	(83,900)	(141,159)
26	Federal taxable income (loss)		470,098	589,628	351,013	369,730	1,176,730	1,883,950
27	Regulatory Federal income tax expense (benefit)	21.00%	98,720	123,822	73,713	77,643	247,113	395,630
28								
29	Regulatory Total income tax expense (benefit)		$119,515	$154,294	$93,332	$96,205	$331,013	$536,789
30								
31	Combined statutory tax rate	26.92%						
32								

Citizens' Electric Company of Lewisburg
Rate Case with Fully Projected Future Test Year 2026

Net Operating Income And Rates of Return
HY 2024, FTY 2025 and FPFTY 2026
Answer to 52 Pa. Code 53.52 c[1]
Support Sheet No. 5- Computation of Rate Base

Line	Description	Ref.	HY 2024 Distribution Only	FTY 2025	FPFTY 2026
1	**Utility Plant in Service**				
2	Assets	Sch. C3, line 28	$ 30,802,761	$ 32,979,090	$ 35,369,114
3	Less: Accumulated Depreciation	Sch. C3, line 28	(15,229,320)	(16,666,142)	(18,189,781)
4			15,573,441	16,312,948	17,179,333
5					
6	Less: Accumulated deferred income taxes (ADIT)	Line 32	(348,561)	(337,325)	(336,658)
7					
8	Less: Customer deposits	Sch. C2, line 52	(299,385)	(299,385)	(299,385)
9	Accrued Pension / OPEB Liability	Line 47	(537,026)	(537,026)	(537,026)
10	Materials & Supplies	Sch. C2, line 23	303,686	303,686	303,686
11			14,692,154	15,442,897	16,309,949
12	Cash Working Capital Allowance	Line 25	415,053	460,000	440,665
13	RATE BASE		$ 15,107,207	$ 15,902,897	$ 16,750,614
14					
15	**Cash Working Capital Allowance:**				
16	Operating Expenses	Sch. C1, line 23	$ 4,915,108	$ 5,479,433	$ 5,510,246
18	Deductions:				
19	Taxes Other Than Income	Sch. C1-3, line 6	441,195	446,255	548,834
20	Uncollectible accounts	Sch. C1-1, line 24	27,330	30,000	26,091
21	Depreciation Expense	Sch. C1, line 19	1,126,159	1,323,181	1,409,998
22	Total Deductions		1,594,683	1,799,436	1,984,923
23	Cash Operating Expenses		3,320,425	3,679,997	3,525,323
24	Cash Operating Expenses Ratio		1/8	1/8	1/8
25	Cash Working Capital Allowance (A plus B)		$ 415,053	$ 460,000	$ 440,665
26					
27	Regulatory Accumluated deferred income tax:				
28	Accumulated depreciation based on tax expense borne by ratepayers		21,209,863	22,378,980	23,637,765
29	Accumulated depreciation based on taxes paid by company		22,869,678	23,985,289	25,240,900
30	(Excess) depreciation taken by company		(1,659,815)	(1,606,310)	(1,603,135)
31	Federal tax rate		21.00%	21.00%	21.00%
32	Regulatory Accumluated deferred income tax (liability)		(348,561)	(337,325)	(336,658)
33					
34					
35					
36					
37					
38					
39					
40					
41					
42	Regulatoy (Liabilities) and Assets				
43	Accrued postretirement cost (Liability)		(555,864)	(555,864)	(555,864)
44	Regulatoy (Liability)		(178,954)	(178,954)	(178,954)
45	Regulatory Assets				
46	Deferred tax asset related to Regulatory Liabiliti	Line 43 X 26.9%	197,792	197,792	197,792
47			(537,026)	(537,026)	(537,026)

WP1. C **Citizens' Electric Company of Lewisburg**
Rate Case with Fully Projected Future Test Year 2026
Workpaper 1 to Schedule C
Historic and Forecast O&M
Years 2013-2026

Line	Account	Acct №	2023 Total	2024 Total	2025 Total	2026 Total	2023 Labor	2024 Labor	2025 Labor	2026 Labor	2023 OH	2024 OH	2025 OH	2026 OH	2023 Transp	2024 Transp	2025 Transp	2026 Transp	2023 Material	2024 Material	2025 Material	2026 Material
1	Ops Exp Eng	580	139,449	147,492	151,142	147,944	65,639	69,376	70,506	66,366	73,810	78,116	80,636	81,578								
1	Station Exp	582	20,968	5,258	13,979	13,478	8,446	1,974	5,821	5,373	9,871	2,264	6,657	6,605			0		2,651	1,020	1,500	1,500
2	OH. Line Exp	583	190,281	191,665	181,002	180,609	76,244	81,245	76,212	70,350	90,703	86,954	87,163	86,474	23,463	23,466	17,127	23,285	(128)		500	500
3	OH. Line Contra (to Plant)	583.97	(25,570)	(17,480)	(18,034)	(19,270)		(12,893)								2,251			(25,570)	(6,838)	(18,034)	(19,270)
4	URD Line Exp	584	77,898	51,848	71,959	71,071	29,963	12,441	22,843	21,086	33,959	15,023	26,126	25,919	12,286		2,990	4,065	1,690	24,384	20,000	20,000
5	Dusk to Dawn Lgts Exp	585DD	3,103	5,271	937	925	345	3,214	407	376	2,728	1,569	465	462	30	488	65	88	0	0	0	0
6	St Lgt & Signal Exp	585SLS	4,992	6,898	4,088	3,997	2,093	1,606	1,788	1,650	2,363	3,632	2,044	2,028	474	1,660	176	239	62	0	80	80
7	Meter Exp	586	43,734	53,805	56,277	56,306	18,234	22,362	22,504	20,773	17,980	25,203	25,737	25,534	5,075	4,512	5,460	7,423	2,445	1,728	2,576	2,576
8	Meter Contra (to Plant)	586.98	(18,472)	(29,763)	(7,319)	(7,789)		(29,763)											(18,472)		(7,319)	(7,789)
9	Customer Inst Exp	587	39,845	41,115	53,765	54,276	16,746	19,074	21,945	20,257	17,868	21,926	25,098	24,900	5,231		6,668	9,065	0	115	54	54
10	Misc. Distribution Exp	588	164,611	211,070	207,816	201,538	78,384	100,860	93,125	85,961	79,239	103,026	106,506	105,664	4,026	4,678	4,804	6,532	2,961	2,506	3,381	3,381
11	Tools	588.5	5,685	13,479	8,000	8,500										3,237			5,685	10,242	8,000	8,500
12	Travel	588.6	74,111	25,691	81,116	80,665	28,955		28,510	26,317	32,533	25,691	32,606	32,349					12,622		20,000	22,000
13	Safety & Training	588.7	38,404	76,891	42,600	45,000		19,559				22,411				233			38,404	34,688	42,600	45,000
14	Mapping	588.8	43,586	23,327	36,446	36,709	9,306	757	5,527	5,102	10,515	816	6,321	6,271		0			23,765	21,754	24,598	25,336
15	Retiree Non Alloc BC+SERF	588.1	68,659	104,646	110,437	110,437													68,659	104,646	110,437	110,437
16	Rents	589	520	530	525	525						530							520		525	525
17	Total Ops		871,804	911,743	994,735	984,922	334,356	289,812	349,187	323,611	371,570	387,161	399,361	397,784	50,585	40,525	37,289	50,696	115,294	194,245	208,898	212,831
18					994,735																	
19	Maint. Sub-Station Exp	592	2,202	25,133	16,832	16,482	1,134	11,213	7,461	6,887	843	13,236	8,533	8,466	225	623	809	1,100	0	61	29	29
20	Maint. OH. Line Exp	593	322,454	303,733	379,720	313,080	133,851	117,957	156,035	144,032	152,261	155,041	178,455	125,636	36,306	30,857	44,338	42,777	37	(122)	892	633
21	Veg Mgmt	593.5	193,991	214,296	209,204	261,671	7,497	21,787	5,815	5,259	7,527	24,661	6,651	4,588	2,467	1,087	1,738	1,677	176,500	166,761	195,000	250,148
22	Pole Insp Mgmt	593.6	47,080	40,536	78,287	44,546	846	0	2,000	1,809	907	0	2,287	1,578	378	0	0	0	44,949	40,536	74,000	41,159
23	Maint. URD Line Exp	594	16,532	13,331	14,361	14,226	6,923	5,237	6,159	5,686	8,026	6,471	7,044	6,989	1,515	1,546	1,097	1,491	67	77	60	60
24	Maint. Line Xfrm	595	85,912	31,968	26,967	26,748	9,440	7,462	7,377	6,809	11,103	9,494	8,437	8,370	3,605	1,094	1,154	1,569	61,764	13,918	10,000	10,000
25	Maint. Dusk to Dawn Lgts	596DD	6,450	1,307	6,605	6,499	2,888	550	1,813	1,674	2,822	617	2,074	2,058	740	140	139	188	0	0	2,579	2,579
26	Maint. St Lgt & Signal Exp	596SLI	16,397	14,607	16,992	16,793	7,303	5,733	7,362	6,796	7,491	7,586	8,420	8,354	1,603	1,288	1,209	1,644	0	0	0	0
27	Maint. of Meter Exp	597	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
28	Total Maintenance		691,018	644,911	748,968	700,046	169,882	169,939	194,023	178,952	190,979	217,106	221,902	166,039	46,839	36,635	50,483	50,446	283,318	221,231	282,560	304,608
29					748,968																	
30	Meter Reading Exp	902	25,085	26,338	26,000	26,000	0	0	0	0	0	0	0	0	0	0	0	0	25,085	26,338	26,000	26,000
31	Customer Records Exp	903	474,976	483,001	486,259	515,335	176,064	174,418	174,043	162,322	192,911	197,831	199,051	199,527	3,558	949	866	1,178	102,444	109,803	112,299	112,299
32	Uncollectibles	904	31,906	27,330	30,000	30,900													31,906	27,330	30,000	30,900
33	Total Customer Accounts		531,968	536,669	542,259	572,235	176,064	174,418	174,043	162,322	192,911	197,831	199,051	199,527	3,558	949	866	1,178	159,435	163,471	168,299	169,199
34					542,259																	
35	Administrative	920	742,994	700,832	732,830	783,157	351,801	323,420	341,855	379,012	391,193	368,269	390,975	404,145		9,143						
36	Misc Admin	921	103,236	15,126	106,327	109,517													103,236	15,126	106,327	109,517
37	Misc Admin- Travel	921.1	20,548	7,817	10,000	2,968													20,548	7,817	10,000	10,300
38	Misc Admin- Comm	921.2	32,667	40,255	34,014	10,096													32,667	40,255	34,014	35,035
39	Misc Admin- Call Center	921.3	77,386	82,455	85,379	25,341													77,386	82,455	85,379	87,940
40	Misc Admin- Transp	921.4	9,655	0	11,267	3,344													9,655		11,267	11,605
41	Outside Services	923	47,103	40,008	37,000	38,110													47,103	40,008	37,000	38,110
42	Property Insurance	924	11,431	11,190	11,059	11,059													11,431	11,190	11,059	11,059
43	Injury & Damage Exp	925	27,561	27,341	28,907	28,907	0	0	0	0					0	0	0	0	27,561	27,341	28,907	28,907
44	CEO Insurance	926.01	(8,321)	(5,885)	0	0													(8,321)	(5,885)	0	0
45	Benefits	926.00	14,525	13,382	8,500	8,755													14,525	13,382	8,500	8,755
46	Reg Commission Exp	928	105,515	70,128	88,208	108,889													105,515	70,128	88,208	108,889
47	General Advertising	930.1	1,061	655	1,000	335													1,061	655	1,000	1,030
48	Misc. General Exp	930.2	89,888	93,095	94,112	95,668													89,888	93,095	94,112	96,935
49	Director's Committee	930.3	14,352	16,850	15,779	16,252													14,352	16,850	15,779	16,252
50	Misc. General Plant	932.4	121,914	155,101	164,713	159,201	47,569	62,272	64,116	59,184	50,741	68,714	73,329	72,750	56	76	0	0	23,548	24,039	27,267	27,267
51	Total General Labor		1,411,514	1,268,350	1,429,095	1,401,599	399,370	385,692	405,971	438,197	441,934	436,983	464,304	476,895	56	9,219	0	0	570,154	436,456	558,820	591,602
52																						
53	**Subtotal**		**3,506,304**	**3,361,673**	**3,715,057**	**3,658,803**	**1,079,671**	**1,019,861**	**1,123,224**	**1,103,082**	**1,197,394**	**1,239,081**	**1,284,618**	**1,240,245**	**101,038**	**87,328**	**88,638**	**102,320**	**1,128,201**	**1,015,403**	**1,218,577**	**1,278,240**
54			0	0	0	0																
55	Capital		537,607	0	556,938	724,306	537,607		556,938	570,902	0	0	0	0	0		0	153,404				
56	Misc. A/R		0	0	0	0	0		0	0	0	0	0	0	0		0	0				
57	Truck		5,609	0	0	0	5,609		0	0	0	0	0	0								
58	OH. Labor(Vac,Hol,Sick,Funeral,Sup		323,568	0	298,015	370,762	323,568		298,015	370,762												
59																						
60	**Total**		**4,373,088**	**3,361,673**	**4,570,010**	**4,753,871**	**1,946,455**	**1,019,861**	**1,978,177**	**2,044,746**	**1,197,394**	**1,239,081**	**1,284,618**	**1,240,245**	**101,038**	**87,328**	**88,638**	**255,724**	**1,128,201**	**1,015,403**	**1,218,577**	**1,278,240**

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No. R-2025-3054394
	:	
Citizens' Electric Compary of Lewisburg, PA	:	

VERIFICATION

I, Greg R. Meyer, hereby state that the facts above set forth in my Rebuttal Testimony, OCA Statement 1R, are true and correct to the best of my knowledge, information, and belief and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa.C.S. § 4904 (relating to unsworn falsification to authorities).

DATED: August 13, 2025

Signature:

Greg R. Meyer

Address: Brubaker & Associates, Inc.
16690 Swingley Ridge Road, Suite 140
Chesterfield, MO 63017

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
v.	)	**R-2025-3054393**
Valley Energy, Inc.	)	

Rebuttal Testimony and Exhibit of

Greg R. Meyer

OCA Statement 1R

On behalf of

Pennsylvania Office of Consumer Advocate

Date Served: August 13, 2025

BRUBAKER & ASSOCIATES, INC.

Project 11858

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
v.	)	**R-2025-3054393**
Valley Energy, Inc.	)	

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EXHIBIT GRM-R1 (VALLEY)

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
v.	)	**R-2025-3054393**
Valley Energy, Inc.	)	

Rebuttal Testimony of Greg R. Meyer

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Greg R. Meyer. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q WHAT IS YOUR OCCUPATION?

A I am a consultant in the field of public utility regulation and a Senior Principal with the firm of Brubaker & Associates, Inc. ("BAI"), energy, economic and regulatory consultants.

Q ARE YOU THE SAME GREG R. MEYER WHO PREVIOUSLY FILED DIRECT TESTIMONY ON JULY 15, 2025, IN THIS PROCEEDING?

A Yes, I am.

Q ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?

A I am appearing on behalf of the Pennsylvania Office of Consumer Advocate ("OCA").

Q PLEASE GIVE A BRIEF OVERVIEW OF YOUR REBUTTAL TESTIMONY.

A My Rebuttal Testimony will address certain issues that the OCA would support and the revenue requirement impact from those issues. I am not addressing all issues of agreement due to the value of the issues, but the OCA will support those adjustments in either settlement negotiations or at the rate case hearings.

My silence regarding any issue should not be construed as an endorsement of or acquiescence to positions advanced by Valley Energy, Inc. ("Valley").

Q WHAT ADJUSTMENTS WILL YOU BE DISCUSSING IN YOUR REBUTTAL TESTIMONY?

A My Rebuttal Testimony will address the following issues:

- The adoption of Valley's updates.
- The adoption of the 2026 state income tax rate of 7.49%.
- The normalization versus amortization of rate case expense and rate base treatment.

Q HAVE YOU PREPARED EXHIBIT GRM-R1 (VALLEY) TO SHOW THE IMPACTS OF THESE TWO ISSUES ON THE OCA'S PROPOSED REVENUE REQUIREMENT?

A Yes. I have prepared Exhibit GRM-R1 (Valley) that shows the revenue requirement impact from the issues the OCA is supporting.

Table GRM-1 (Valley)

OCA Revenue Requirment Adjustments

Line	Description	Amount
1	Company Proposed Revenue Requirement Increase[1]	$ 1,626,099
	OCA Adjustments:	
2	Return on Equity	$ (375,363)
3	Labor	$ (19,892)
4	Acct 880 and 925	$ (67,810)
5	Depreciation	$ (267,031)
6	Credit Card Fee	$ 67,627
7	Income Tax Rate	$ (15,416)
8	Rate Case Reg Liability	$ (20,785)
9	Total OCA Adjustments	$ (698,670)
10	OCA Proposed Revenue Requirement Increase	$ 927,429

Source:
[1]OCA-I-1 Attachment A (Schedule A-D) Tab "C1."

VALLEY'S UPDATES

Q HAS VALLEY IDENTIFIED ANY ISSUES THAT THEY PROPOSE TO UPDATE THAT WOULD LOWER ITS REQUESTED REVENUE REQUIREMENT?

A Yes, according to the Bureau of Investigation and Enforcement ("I&E") witness Christine Wilson, Valley has indicated that incorrect source documents were used to develop its revenue requirement. Valley is in the process of updating its filing to reflect

corrections of the source documents.[1] Valley indicated that adjustments and potential errors could impact the following accounts:

- Mains and Services (Account #874)
- Ind./Com. Meters, Reg. (Account #876)
- Meters & Reg.-City Gate (Account #877)
- Meters & House Reg. (Account #878)
- Customer Installations (Account #879)
- Other Operations Expense (Account #880)
- Meas. & Reg. – Gen. (Account #889)

I will update my Exhibit GRM-R1 once I receive quantification of the errors.

INCOME TAX RATE

Q HAVE YOU READ THE DIRECT TESTIMONY OF THE OFFICE OF SMALL BUSINESS ADVOCATE ("OSBA") WITNESS JUSTIN FARR AND I&E WITNESS CHRISTINE WILSON ADDRESSING THE STATE INCOME TAX RATE?

A Yes, I have.

[1]Wilson Direct Testimony (Valley), I&E Statement 1, page 32, lines 10-13.

Q WHAT DO THESE WITNESSES PROPOSE TO USE FOR THE STATE INCOME TAX RATE?

A Both witnesses propose to use the state income tax rate of 7.49% which will be in effect in 2026.[2] Both witnesses discuss that on July 8, 2022, Pennsylvania House Bill 1342 was signed into law as Act 53 of 2022. Act 53 lowered the state corporate income tax rate over several years to a 4.99% state corporate tax rate effective in 2031.

Q DO YOU SUPPORT THIS POSITION?

A Yes, the 2026 state corporate tax rate of 7.49% should be used to calculate Valley's revenue requirement. I have incorporated the 2026 state corporate tax rate (7.49%) in my revenue requirement calculation and reflected the impact on my Exhibit GRM-R1 (Valley). The new corporate tax rate decreases Valley's revenue requirement by $15,416. I would also note that this adjustment includes the effects in the cash working capital balance required for this revenue requirement issue.

NORMALIZATION OF RATE CASE EXPENSES

Q HAVE YOU READ THE REBUTTAL TESTIMONY OF I&E WITNESS CHRISTINE WILSON DISCUSSING RATE CASE EXPENSE?

A Yes, I have.

[2]Wilson Direct Testimony (Valley), I&E Statement 1, page 31.

Q PLEASE SUMMARIZE MS. WILSON'S POSITION.

A Ms. Wilson supports normalizing rate case expense over the projected period of time that will occur between Valley's rate cases. Ms. Wilson argues correctly that rate case expense should be normalized instead of establishing an amortization period. Ms. Wilson also recognizes that rate case expense is an operating expense that is incurred periodically. Normalizing this expense for equal recovery over a multi-year period is the proper ratemaking principle. I support normalizing rate case expense. I support Valley's proposed three-year rate case interval for normalizing rate case expense based on the Company's recent two rate case filings.

Q WHAT RATEMAKING TREATMENT DID VALLEY PROPOSE?

A According to Ms. Wilson, Valley proposed to amortize rate case expense over a multi-year period. Given that Valley chose to amortize rate case expense, it also is requesting rate base treatment for the unamortized rate case expense balance.

Q ARE YOU SUPPORTIVE OF INCLUDING THE UNAMORTIZED PORTION OF RATE CASE EXPENSE IN VALLEY'S RATE BASE?

A Absolutely not. Rate case expense is a normal operating expense of the utility. Normalizing the rate case expense recovery over a multi-year period is the proper method to collect these recurring, but not annual expenses. By including rate case expense in rate base, Valley's shareholders would earn a profit on a normal and recuring expense item. I am opposed to enhancing the profits of Valley's shareholders for the inclusion of rate case expense in rate base. Furthermore, rate cases also provide benefits

for Valley's shareholders. There is no need to reward shareholders further by allowing a profit return on those expenses.

Q WHAT IS THE REVENUE REQUIREMENT IMPACT FOR DISALLOWING RATE BASE TREATMENT OF RATE CASE EXPENSE?

A Removing the unamortized balance of rate case expense from Valley's rate base would lower Valley's revenue requirement by $20,785.

CONCLUSION

Q DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A Yes, it does.

541217

Table GRM-1 (Valley)

OCA Revenue Requirment Adjustments

Line	Description	Amount
1	Company Proposed Revenue Requirement Increase[1]	$ 1,626,099
	OCA Adjustments:	
2	Return on Equity	$ (375,363)
3	Labor	$ (19,892)
4	Acct 880 and 925	$ (67,810)
5	Depreciation	$ (267,031)
6	Credit Card Fee	$ 67,627
7	Income Tax Rate	$ (15,416)
8	Rate Case Reg Liability	$ (20,785)
9	Total OCA Adjustments	$ (698,670)
10	OCA Proposed Revenue Requirement Increase	$ 927,429

Source:
[1]OCA-I-1 Attachment A (Schedule A-D) Tab "C1."

Valley Energy

Change Log of OCA Adjustments to Revenue Requirement

Line	Issue	Changed Cells	Starting Revenue Requirement Increase	Ending Revenue Requirement Increase	OCA Adjustment	Notes and Sources
			(1)	(2)	(3)	(4)
1	Return on Equity	Changed Cell E9 to 9.5% on Tab "C1-2"	$ 1,626,099	$ 1,250,736	$ (375,363)	See Mr. Christopher Walters, OCA Statement 2
2	Labor	On Tab "WP1_C", changed Cells H8 to H27 to reflect a 4% increase in total labor for each year from 2024 in relation to their proportion of expense to the total in Row 28.	$ 1,250,736	$ 1,230,844	$ (19,892)	See Mr. Greg Meyer, OCA Statement 1
3	Account 880	Subtracted $35,452 from non-labor Account 880 Cells on Tab "WP1_C" in proportion to their company proposed non-labor 2026 level over their total non-labor 2026 level.	$ 1,230,844	$ 1,194,658	$ (36,187)	See Mr. Greg Meyer, OCA Statement 1
4	Account 925	Subtracted $30,981 from non-labor Account 925 Cells on Tab "WP1_C" in proportion to their company proposed non-labor 2026 level over their total non-labor 2026 level.	$ 1,194,658	$ 1,163,035	$ (31,623)	See Mr. Greg Meyer, OCA Statement 1
5	Depreciation	On Tab "C3", removed the value from Cell AC32 and reduced Cell AC37 to $19,515.	$ 1,163,035	$ 896,004	$ (267,031)	See Mr. Greg Meyer, OCA Statement 1; $19,515 reflects a 3 year amortization of the remaining expense.
6	Credit Card Fee	Added 66,253 to Cell H91 on Tab "WP1_C"	$ 896,004	$ 963,630	$ 67,627	See Ms. LeeAnn Wise, OCA Statement 4
7	Income Tax Rate	Changed Cell C27 on Tab "C1-4" to 7.49% and changed the cells D29 to I29 to reference Cell C27.	$ 963,630	$ 948,214	$ (15,416)	See https://www.pa.gov/agencies/revenue/resources/tax-rates/corporation-tax-rates for 2026 Tax Rate of 7.49%
8	Rate Case Reg Liability	Removed values from Cells F45 and G45 on Tab "C1-5"	$ 948,214	$ 927,429	$ (20,785)	See Mr. Greg Meyer, OCA Statement 1-R
9				OCA Total Adjustments	$ (698,670)	

C1

Valley Energy, Inc. (PA)
Rate Case with Fully Projected Future Test Year 2026
Net Operating Income And Rates of Return
Years Ended 12/31/2024, 12/31/2025 and 12/31/2026
Answer to 52 Pa. Code 53.52 c[1]

Line	Description	Historic Year December 31, 2024		Future Test Year December 31, 2025	Present Rates Fully Projected Future Test Year December 31, 2026	Revenue Requirement Fully Projected Future Test Year December 31, 2026	Proposed Rates Fully Projected Future Test Year December 31, 2026
		Per Books	Distribution Only	Distribution Only	Distribution Only	Distribution Only	Distribution Only
1	REVENUE						
2	Residential	$4,526,671	$2,823,518	$3,135,633	$3,159,547		3,692,217
3	Commercial and industrial	1,764,263	893,396	976,270	976,270		1,139,601
4	Transportation	2,217,436	2,217,436	2,321,925	2,347,099		2,578,493
5	Operating revenue	8,508,370	5,934,349	6,433,828	6,482,916	7,410,345	7,410,311
6	Other revenue, net	21,204	21,204	23,575	23,575	23,575	23,575
7	Total Revenue	8,529,574	5,955,553	6,457,402	6,506,491	7,433,920	7,433,885
8	*ccf*	*32,948,558*		*34,886,478*	*34,930,969*	*34,930,969*	*34,930,969*
9	EXPENSES				Increase	927,429	
10	Purchased gas (in revenue)	3,650,808					
11	Distribution	1,885,489	1,885,489	1,725,247	1,892,877	1,892,877	1,892,877
12	Customer accounting & collection	649,422	649,422	742,899	832,271	840,765	840,765
13	Rate case expense normalization				92,222	92,222	92,222
14	Administrative & general expenses	1,119,082	1,119,082	1,194,040	1,242,963	1,242,963	1,242,963
15	Total Operating expenses	7,304,802	3,653,994	3,662,186	4,060,333	4,068,826	4,068,826
16							
17	Depreciation expense	1,307,234	1,307,234	1,425,492	1,341,376	1,341,376	1,341,376
18	Taxes other than income	29,354	29,354	31,385	33,587	33,587	33,587
19							
20	Total Expenses	8,641,390	4,990,582	5,119,063	5,435,297	5,443,790	5,443,790
21							
22	Oper Inc (Loss) before Income Tax	(111,816)	964,972	1,338,339	1,071,194	1,990,130	1,990,095
23							
24	Income tax expense	(324,412)	18,792	87,093	(71,756)	175,594	175,585
25	NET UTILITY OPERATING INCOME (LOSS) (A)	$212,596	$946,179	$1,251,247	$1,142,951	$1,814,535	$1,814,510
26							
27	RATE BASE (B)	$21,774,747	$21,774,747	$23,253,260	$25,132,069	$25,132,069	$25,132,069
28	RATE OF RETURN ON RATE BASE (	0.98%	4.35%	5.38%	4.55%	7.22%	7.22%
29							

C1-2

Valley Energy, Inc. (PA)
Rate Case with Fully Projected Future Test Year 2026

Support Sheet No. 2- Summary of Cost of Capital and Fair Rate of Return Based upon a Hypothetical Ratemaking Capital Structure
12/31/2026

Line	Type of Capital	Ratios (1)	Cost Rate	Weighted Cost Ra
1	Long-Term Debt	51.06%	5.03%	2.57%
2	Common Equity	48.94%	9.50%	4.65%
3	Total	100.00%		7.22%
4	TargetROR			7.22%
5				
6	[1] Recommended hypothetical capital structure ratios as discussed in direct testimony.			

Valley Energy, Inc. (PA)
Rate Case with Fully Projected Future Test Year 2026
Net Operating Income And Rates of Return
Years Ended 12/31/2024, 12/31/2025 and 12/31/2026
Answer to 52 Pa. Code 53.52 c[1]
Support Sheet No. 4- Income Tax Calculations

Line	Ddescription		Historic Year December 31, 2024		Future Test Year December 31, 2025	PRESENT RATES Fully Projected Future Test Year December 31, 2026	FULL REVENUE REQUIREMENT Fully Projected Future Test Year December 31, 2026	PROPOSED RATES Fully Projected Future Test Year December 31, 2026
			Per Books	Distribution Only	Distribution Only	Distribution Only	Distribution Only	Distribution Only
1	Net Operating Income Excluding Income Taxes		($111,816)	$964,972	$1,338,339	$1,071,194	$1,990,130	$1,990,095
3	Non-Operating Expenses:							
4	Synchronized interest expense:							
5	Rate base		21,774,747	21,774,747	23,253,260	25,132,069	25,132,069	25,132,069
6								
7	Rate base for interest compuation		21,774,747	21,774,747	23,253,260	25,132,069	25,132,069	25,132,069
8	Weighted Cost of debt		2.570%	2.570%	2.570%	2.570%	2.570%	2.570%
9	Synchronized interest expense		559,611	559,611	597,609	645,894	645,894	645,894
10	Taxable income before depreciation tax adjustments		(671,427)	405,361	740,731	425,300	1,344,236	1,344,201
12	Pennsylvania depreciation adjustment:							
13	Tax depreciation (using DDB method)		(2,115,013)	(2,115,013)	(2,528,871)	(2,227,569)	(2,227,569)	(2,227,569)
14	Book depreciation		1,307,234	1,307,234	1,425,492	1,341,376	1,341,376	1,341,376
15	Pennsylvania depreciation adjustment		(807,779)	(807,779)	(1,103,379)	(886,193)	(886,193)	(886,193)
16	Pennsylvania taxable income		(1,479,206)	499,455	322,114	(460,893)	458,043	458,008
17	Regulatory Pennsylvania income tax expense	7.49%	(110,793)	37,409	24,126	(34,521)	34,307	34,305
19	Federal depreciation adjustment:		7.49%	7.49%	7.49%	7.49%	7.49%	7.49%
20	Tax depreciation (using SL method)		(1,763,836)	(1,763,836)	(1,842,256)	(1,978,510)	(1,978,510)	(1,978,510)
21	Book depreciation		1,307,234	1,307,234	1,425,492	1,341,376	1,341,376	1,341,376
22	Federal depreciation adjustment		(456,603)	(456,603)	(416,763)	(637,133)	(637,133)	(637,133)
24	Taxable income before depreciation tax adjustments		(671,427)	405,361	740,731	425,300	1,344,236	1,344,201
25	Federal depreciation adjustment		(456,603)	(456,603)	(416,763)	(637,133)	(637,133)	(637,133)
26	Pennsylvania income tax expense		110,793	(37,409)	(24,126)	34,521	(34,307)	(34,305)
27	Federal taxable income		(1,017,237)	(88,651)	299,841	(177,312)	672,795	672,763
28	Regulatory Federal income tax expense	21.00%	(213,620)	(18,617)	62,967	(37,236)	141,287	141,280
29	Regulatory Total income tax expense		($324,412)	$18,792	$87,093	($71,756)	$175,594	$175,585
31	Deferred Federal Income Tax expense (included in above):							
32	Tax depreciation (using SL method)		1,763,836	1,763,836	1,842,256	1,978,510	1,978,510	1,978,510
33	Tax depreciation (using DDB method)		2,115,013	2,115,013	2,528,871	2,227,569	2,227,569	2,227,569
34			351,176	351,176	686,615	249,059	249,059	249,059
35	Federal tax rate		21.00%	21.00%	21.00%	21.00%	21.00%	21.00%
36	Deferred Federal income tax (credit)		$73,747	$73,747	$144,189	$52,302	$52,302	$52,302
37	Combined statutory tax rate	26.92%	26.92%	26.92%	26.92%	26.92%	26.92%	26.92%

C1-5

Valley Energy, Inc. (PA)
Rate Case with Fully Projected Future Test Year 2026
Net Operating Income And Rates of Return
Years Ended 12/31/2024, 12/31/2025 and 12/31/2026
Answer to 52 Pa. Code 53.52 c[1]
Support Sheet No. 5- Computation of Rate Base

Line	Description	Source	Historic Year December 31, 2024	Future Test Year December 31, 2025	Fully Projected Future Test Year December 31, 2026
1	Utility Plant in Service				
2	Assets	Schedule C3	$ 43,575,245	$ 46,639,469	$ 49,963,792
3	Less: Accumulated Depreciation	Schedule C3	(20,753,495)	(22,356,239)	(23,860,537)
4			22,821,750	24,283,230	26,103,255
5					
6	Less: Accumulated deferred income taxes	Line 31	(484,177)	(459,323)	(438,298)
7	Less: Customer deposits	Schedule C2	(394,763)	(394,763)	(394,763)
8	Natural gas inventories- avg balance for year	Workpaper 5 to Sch C	1,198,570	1,198,570	1,198,570
9	Unbundled, to be Recovered in GCR	To Schedule C4	(1,198,570)	(1,198,570)	(1,198,570)
10	Accrued OPEB Liability / OPEB Asset, net	Line 38	(871,589)	(871,589)	(871,589)
11	Materials & Supplies	Schedule C2	244,244	244,244	244,244
12			21,315,465	22,801,799	24,642,849
13	Cash Working Capital Allowance	Line 24	459,282	451,461	489,220
14	RATE BASE		$ 21,774,747	$ 23,253,260	$ 25,132,069
15					
16	Cash Working Capital Allowance:				
17	Operating Expenses	Schedule C1	$ 8,641,390	$ 5,119,063	$ 5,435,297
18	Deductions:				
19	Purchased Gas	Schedule C1	3,650,808	0	0
20	Depreciation Expense, Uncollectible, TOTI	Schedule C1	1,316,328	1,507,372	1,521,534
21	Total Deductions		4,967,136	1,507,372	1,521,534
22	Cash Operating Expenses		3,674,254	3,611,691	3,913,762
23	Cash Operating Expenses Ratio		1/8	1/8	1/8
24	Cash Working Capital Allowance		$ 459,282	$ 451,461	$ 489,220
25					
26	Regulatory Accumluated deferred income tax:				
27	Accumulated depreciation based on tax expense borne by ratepayers		37,481,985	39,313,415	41,266,769
28	Accumulated depreciation based on taxes paid by company		39,787,591	41,500,668	43,353,900
29	(Excess) depreciation taken by company		(2,305,606)	(2,187,253)	(2,087,132)
30	Federal tax rate		21.00%	21.00%	21.00%
31	Regulatory Accumluated deferred income tax (liability)		$ (484,177)	$ (459,323)	$ (438,298)
32					
33	Accrued OPEB Liability / OPEB Asset, net				
34	Accrued postretirement cost (Liability)		(816,705)	(816,705)	(816,705)
35	Regulatory (Liability)		(375,898)	(375,898)	(375,898)
36	Regulatory Assets				
37	Deferred tax asset related to Regulatory Liabilities		321,014	321,014	321,014
38			(871,589)	(871,589)	(871,589)
39					

C3

Valley Energy, Inc. (PA)
Rate Case with Fully Projected Future Test Year 2026
Original Cost of Utility Plant in Service
Years Ended 12/31/2024, 12/31/2025 and 12/31/2026
Answer to 52 Pa. Code 53.52 c[3]

Line	Acct No.	Account Title		12/31/2024 Balance	Year 2025 Additions	Year 2025 Removals	12/31/2025 Balance	Year 2026 Additions	Year 2026 Removals	12/31/2026 Balance	Depr. Rate	Year 2024 Depr Exp	Accumulated Depreciation 12/31/2024 Balance
				Original Cost				Original Cost					
1	*Distribution Plant.*												
2	114	Gas Plant Acquisition Adjustment		3,361,289			3,361,289			3,361,289	3.47%	88,183	2,847,221
3	366	Trans. Structures and improvements	(A)	117,592	0		117,592	0		117,592	0.62%	730	7,146
4	367	Trans. Mains	(A)	1,917,201	0		1,917,201	0		1,917,201	1.79%	34,311	1,225,993
5	369	Trans. Meas / Reg Sta Equp	(A)	402,427	0		402,427	0		402,427	4.40%	17,723	296,228
6	374	Land & Land Rights		15,652	0		15,652	0		15,652	4.40%		0
7	375	Structures and improvements		204,060	1,218,878		1,422,938	457,937		1,880,875	2.63%	5,363	105,540
8	376S	Mains- Steel		3,820,156	43,909		3,864,065	44,080		3,908,144	3.15%	120,867	2,769,349
9	376P	Mains- Plastic		11,410,116	223,134	(434)	11,632,816	1,188,320	(404)	12,820,732	2.02%	226,954	3,788,947
10	378	Meas / Reg Sta Equp		1,590,567	406,925		1,997,492	244,879		2,242,371	6.72%	100,343	1,221,758
11	380S	Services- Steel		581,198	0	(9,027)	572,171	0	(10,385)	561,786	3.04%	18,399	218,783
12	380P	Services- Plastic		9,843,941	767,950	(1,364)	10,610,526	1,055,387	(14,366)	11,651,547	3.41%	318,053	4,396,438
13	381	Meters		1,945,136	47,842		1,992,978	61,305		2,054,284	2.74%	62,737	1,135,963
14	381RC	Transponders- Res/Comm		1,010,228			1,010,228			1,010,228	2.74%	22,968	312,762
15	381AMR	Meters-AMR		282,510	2,009		284,519	9,121		293,640	2.74%	3,870	8,670
16	381Prot	Meters-Protection		61,435	10,611		72,046	0		72,046	2.74%	842	1,356
17	383	House regulators		335,586	4,500		340,086	4,500		344,586	3.22%	10,792	260,864
18	385	Indu Meas / Reg Sta Equp		1,260,536	26,400		1,286,936	13,200		1,300,136	4.11%	40,510	856,743
19	387	Other equipment		9,978	0		9,978	0		9,978	3.66%	364	7,651
20	Total Distribution Plant			38,169,608	2,752,157	(10,826)	40,910,940	3,078,729	(25,156)	43,964,513		1,073,009	19,461,412
21													
22	*General Plant*												
23	390	Structures & Improvements		4,055,042	0		4,055,042	0		4,055,042	2.43%	74,191	870,711
24	391	Office Furniture & Equipment		1,230,002	6,200		1,236,202	0		1,236,202	13.10%	267,559	1,115,240
25	391C	Computer equipment		147,442	147,442		294,884	125,750		420,634	6.75%	9,552	9,952
26	392	Transportation Equipment		1,214,676	80,000		1,294,676	100,000		1,394,676	12.00%	68,719	1,030,813
27	393	Stores Equipment		48,547	20,000		68,547	0		68,547	6.67%	2,804	25,535
28	394	Tools, Shop & Garage Equipment		717,363	68,750		786,113	45,000		831,113	5.00%	27,591	523,999
29	396	Power Operated		499,528	0		499,528	0		499,528	11.76%	48,647	382,238
30	397	Communication Equipment		245,077	500		245,577	0		245,577	6.67%	10,527	179,026
31	398	Miscellaneous Equipment		14,718			14,718			14,718	6.67%	895	1,790
32	301	Intangible plant, organization		22,107			22,107			22,107	0.00%		
33	389	Land & Land Rights		572,424			572,424			572,424	0.00%		
34		Total General Plant		8,766,926	322,892	0	9,089,818	270,750	0	9,360,568		510,485	4,139,304
35													
36		Less: Acquisition		(3,361,289)	0	0	(3,361,289)	0	0	(3,361,289)		(88,183)	(2,847,221)
37		Total Plant in Service		$43,575,245	$3,075,049	($10,826)	$46,639,469	$3,349,479	($25,156)	$49,963,792		$1,495,311	$20,753,495
38		Less: Clearing, Charged to NY		$46,936,534			$50,000,758			$53,325,081		(188,077)	$23,600,716
39				$46,936,534			$50,000,758			$53,325,081		$1,307,234	$23,600,716

C3

Valley Energy, Inc. (PA)
Rate Case with Fully Projected Future Test Year 20
Original Cost of Utility Plant in Service
Years Ended 12/31/2024, 12/31/2025 and 12/31/202
Answer to 52 Pa. Code 53.52 c[3]

Line	Acct No.	Account Title	Accumulated Depreciation Year 2025 Depr Exp	Accumulated Depreciation Year 2025 Removals	Accumulated Depreciation 12/31/2025 Balance	Accumulated Depreciation Year 2026 Depr Exp	Accumulated Depreciation Year 2026 Removals	Accumulated Depreciation 12/31/2026 Balance	Net Book Value 12/31/2026 Balance
1	*Distribution Plant.*								
2	114	Gas Plant Acquisition Adjustment	116,637		2,963,858	116,637		3,080,494	280,795
3	366	Trans. Structures and improvements	729		7,875	729		8,604	108,988
4	367	Trans. Mains	34,318		1,260,311	34,318		1,294,629	622,572
5	369	Trans. Meas / Reg Sta Equp	17,707		313,935	17,707		331,642	70,785
6	374	Land & Land Rights	689		689	689		1,377	14,275
7	375	Structures and improvements	21,395		126,935	43,445		170,380	1,710,495
8	376S	Mains- Steel	121,026		2,890,375	122,412		3,012,788	895,357
9	376P	Mains- Plastic	232,738	(434)	4,021,251	246,985	(404)	4,267,832	8,552,900
10	378	Meas / Reg Sta Equp	120,559		1,342,317	142,459		1,484,776	757,594
11	380S	Services- Steel	17,668	(9,027)	227,424	17,394	(10,385)	234,433	327,353
12	380P	Services- Plastic	348,772	(1,364)	4,743,846	379,813	(14,366)	5,109,292	6,542,255
13	381	Meters	53,952		1,189,915	55,447		1,245,363	808,921
14	381RC	Transponders- Res/Comm	27,680		340,442	27,680		368,122	642,106
15	381AMR	Meters-AMR	7,768		16,438	7,921		24,359	269,281
16	381Prot	Meters-Protection	1,829		3,185	1,974		5,159	66,887
17	383	House regulators	10,878		271,742	11,023		282,766	61,820
18	385	Indu Meas / Reg Sta Equp	52,351		909,094	53,164		962,258	337,878
19	387	Other equipment	365		8,016	365		8,381	1,597
20	Total Distribution Plant		1,187,061	(10,826)	20,637,648	1,280,163	(25,156)	21,892,656	22,071,857
22	*General Plant*								
23	390	Structures & Improvements	98,538		969,249	98,538		1,067,786	2,987,256
24	391	Office Furniture & Equipment	161,536		1,276,776			1,276,776	(40,574)
25	391C	Computer equipment	14,928		24,880	24,149		49,029	371,605
26	392	Transportation Equipment	150,561		1,181,374	161,361		1,342,735	51,941
27	393	Stores Equipment	3,905		29,440	4,572		34,012	34,535
28	394	Tools, Shop & Garage Equipment	37,587		561,586	40,431		602,017	229,096
29	396	Power Operated	58,744		440,982	19,515		460,497	39,031
30	397	Communication Equipment	16,363		195,389	16,380		211,769	33,808
31	398	Miscellaneous Equipment	982		2,772	982		3,753	10,965
32	301	Intangible plant, organization	0		0	0		0	22,107
33	389	Land & Land Rights	0		0	0		0	572,424
34		Total General Plant	543,145	0	4,682,449	365,927	0	5,048,376	4,312,192
36		Less: Acquisition	(116,637)	0	(2,963,858)	(116,637)	0	(3,080,494)	(295,069)
37		Total Plant in Service	$1,613,569	($10,826)	$22,356,239	$1,529,454	($25,156)	$23,860,537	$26,088,980
38		Less: Clearing, Charged to NY	(188,077)			(188,077)			
39			$1,425,492			$1,341,376			26,103,255

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Valley Energy, Inc. (PA)
Rate Case with Fully Projected Future Test Year 2026
Workpaper 2 to Schedule C
Future O&M
Years 2025 and 2026

Line	Dept.	Account	*rType22*	*rAcct25*	*rFTY25* Total 2025	*rFPFTY26* Total 2026
1	**PAYROLL - DIRECT LABOR**					
2	LABOR OPER SUPR & ENG	870.01	Labor	870	103,788	111,597
3	LABOR MAINS & SERV EXP	874.01	Labor	874	136,278	190,232
4	LABOR MEAS & REG STAT EXP	875.01	Labor	875	35,758	39,433
5	LABOR IND/CM MTR/REG MNT	876.01	Labor	876	31,539	35,807
6	LABOR MEAS & REG CITY GATE	877.01	Labor	877	6,288	6,955
7	LABOR MTR/HSE REG EXP	878.01	Labor	878	60,218	66,449
8	LABOR CUST INSTALL EXP	879.01	Labor	879	72,453	78,992
9	LABOR OQ TRAINING	880.01	Labor	880	20,603	27,547
10	LABOR MAINT SUPV & ENG	885.01	Labor	885	15,514	16,064
11	LABOR STURCTURES & IMPR	886.01	Labor	886	7,488	5,944
12	LABOR MAINT OF MAIN	887.01	Labor	887	36,769	42,609
13	LABOR MEAS & REG STAT EQUIP	889.01	Labor	889	20,343	17,755
14	LABOR MAINT. INDUST. M&R STATION	890.01	Labor	890	8,837	9,983
15	LABOR MAINT CITY GATE STAT	891.01	Labor	891	1,715	1,948
16	LABOR MAINT OF SERVICE	892.01	Labor	892	20,480	25,608
17	LABOR MAINT MTR & HSE REG	893.01	Labor	893	29,166	23,379
18	LABOR METER READING EXP	902.01	Labor	902	9,734	6,097
19	LABOR CUST REC/COLLECTIONS	903.01	Labor	903	214,654	226,152
20	LABOR ADMINISTRATION	920.01	Labor	920	276,347	293,409
21	LABOR GENERAL PLT MAINTENANCE	932.01	Labor	932	8,168	8,075
22	**Total Direct Labor**				**1,116,140**	**1,234,034**
23						
24	TRANSP OPER SUPR & ENG	870.02	Trans	870	8,447	8,700
25	TRANSP MAINS & SERVICE EXP	874.02	Trans	874	30,734	31,656
26	TRNSP MEAS & REG STAT EXP	875.02	Trans	875	8,638	8,897
27	TRANS IND/CM/MTR/REG/MNT	876.02	Trans	876	4,480	4,614
28	TRANSP MEAS & REG CITY GATE	877.02	Trans	877	2,640	2,719
29	TRANSP MTR/HSE REG EXP	878.02	Trans	878	8,833	9,098
30	TRANSP CUST INSTALL EXP	879.02	Trans	879	11,297	11,636
31	TRANSP OQ TRAINING	880.02	Trans	880	136	24
32	TRANSP MAINT SUPV & ENG	885.02	Trans	885	3,271	3,369
33	TRANSP MAINT STRUCTURES & IMPR	886.02	Trans	886	653	673
34	TRANSP MAINT OF MAIN	887.02	Trans	887	5,210	5,366
35	TRANSP MAINT MEAS/REG STAT EQ	889.02	Trans	889	1,461	1,505
36	TRANSP MAINT INDUS M&R STAT	890.02	Trans	890	212	218
37	TRANSP MAINT CITY GATE STAT	891.02	Trans	891	756	779
38	TRANSP MAINT OF SERVICE	892.02	Trans	892	7,657	7,887
39	TRANSP MAINT MTR HSE REG	893.02	Trans	893	2,134	2,198
40	TRANS METER READING EXP	902.02	Trans	902	2,499	2,574
41	TRANSP CUST REC/COLLECTIONS	903.02	Trans	903	3,923	4,041
42	TRANSP ADMINSTRATION	920.02	Trans	920	18,770	19,333
43	TRANS MAINT GENERAL PLANT	932.02	Trans	932	1,518	1,564
44	**Total Trans. Exp**				**123,269**	**126,851**
45						

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Valley Energy, Inc. (PA)
Rate Case with Fully Projected Future Test Year 2026
Workpaper 2 to Schedule C
Future O&M
Years 2025 and 2026

Line	Dept.	Account	*rType22*	*rAcct25*	*rFTY25* Total 2025	*rFPFTY26* Total 2026
46	C&T OH OPER SUPR & ENG	870.03	OH	870	26,794	29,264
47	C&T OH MAINS & SERVICE EXP	874.03	OH	874	35,181	49,885
48	C&T OH MEAS & REG STAT EXP	875.03	OH	875	9,231	10,341
49	C&T OH IND/CM MTR/REG MNT	876.03	OH	876	8,142	9,390
50	C&T OH CITY GATE MEAS/REG STAT	877.03	OH	877	1,623	1,824
51	C&T OH MTR/HSE REG EXP	878.03	OH	878	15,546	17,425
52	C&T OH CUST INSTALL EXP	879.03	OH	879	18,704	20,714
53	C&T OH OQ TRAINING	880.03	OH	880	5,319	1,226
54	C&T OH MAINT SUPV & ENG	885.03	OH	885	4,005	4,213
55	C&T OH MAINT STRUCTURES & IMPR	886.03	OH	886	1,933	1,559
56	C&T OH MAINT OF MAIN	887.03	OH	887	9,492	11,174
57	C&T OH MAINT M&R STAT EQUIP	889.03	OH	889	5,252	4,656
58	C&T OH MAINT INDUST M&R STATION E	890.03	OH	890	2,281	2,618
59	C&T OH MAINT CITY GATE STAT	891.03	OH	891	443	511
60	C&T OH MAINT SERVICES EXP	892.03	OH	892	5,287	6,715
61	C&T OH MAINT MTR & HSE REG	893.03	OH	893	7,529	6,131
62	C&T OH METER READING EXP	902.03	OH	902	2,513	1,599
63	C&T OH CUST REC/COLLECTIONS	903.03	OH	903	55,414	59,305
64	C&T OH ADMINSTRATION	920.03	OH	920	71,341	76,942
65	C&T OVHD GENERAL PLANT	923.03	OH	920	2,109	2,118
66	**Total C&T OH**				**288,139**	**317,608**
67						
68	VE OH OPER SUPR & ENG	870.05	OH	870	100,001	109,223
69	VE OH MAINS & SERVICE EXP	874.05	OH	874	131,306	186,186
70	VE OH MEAS & REG STAT EXP	875.05	OH	875	34,453	36,913
71	VE OH IND/CM/MTR/REG MNT EXP	876.05	OH	876	30,388	34,862
72	VE OH CITY GATE MEAS & REG	877.05	OH	877	6,059	6,475
73	VE OH MTR/HSE REG EXP	878.05	OH	878	58,021	63,918
74	VE OH CUST INSTALL EXP	879.05	OH	879	69,810	76,507
75	VE OH OQ TRAINING	880.03	OH	880	19,851	4,509
76	VE OH MAINT SUPV & ENG	885.05	OH	885	14,948	15,723
77	VE OH MAINT STRUCTURES & IMPR	886.05	OH	886	7,215	2,498
78	VE OH MAINT OF MAIN	887.05	OH	887	35,428	41,703
79	VE OH MAINT M&R STAT EQUIP	889.05	OH	889	19,601	8,839
80	VE OH MAINT. INDUSTR. M&R STATION	890.05	OH	890	8,515	9,482
81	VE OH MAINT CITY GATE STAT	891.05	OH	891	1,652	1,907
82	VE OH MAINT OF SERVICE	892.05	OH	892	19,733	25,063
83	LABOR OH MAINT MTR & HSE REG	893.05	OH	893	28,102	7,931
84	VE OH METER READING EXP	902.05	OH	902	9,379	2,522
85	VE OH CUST REC/COLLECTIONS	903.05	OH	903	206,823	285,238
86	VE OH ADMINISTRATION	920.05	OH	920	266,265	287,169
87	OH MAINT PLANT	932.05	OH	932	7,870	5,527
88	**Total VE Labor OH**				**1,075,419**	**1,212,194**
89						
90						
91	FUEL (COMPANY USE)	842.10	Other	842	21,130	20,347
92	DISTRIB LOAD DISPATCHING	871.45	Mat	871	6,763	7,101
93	MAT & SUP MAINS & SERV EXP	874.45	Mat	874	32,675	32,675
94	CALL CENTER EXPENSE	874.50	Other	874	74,285	76,514
95	TOOLS, EQUIPMENT & MAINTENANCE	874.99	Mat	874	10,029	10,330
96	MAT/SUP MEAS & REG STAT EXP	875.45	Mat	875	10,207	10,513
97	MAT & SUP IND/CM/MTR/REG/MNT	876.45	Mat	876	7,968	9,164
98	MAT/SUP CITYGATE MEAS/REG STA	877.45	Mat	877	13,637	14,046
99	MAT & SUP MTR/HSE REG EXP	878.45	Mat	878	1,634	1,683
100	MAT/SUP CUST INSTALL EXP	879.45	Mat	879	920	947
101	MAT/SUP OQ TRAINING	880.45	Mat	880	8,526	1,491
102	RENTS - DISTRIBUTION EXPENSE	881.45	Mat	881	6,222	6,669
103	MAT/SUP MAINT STRUCTURE/IMPR	886.45	Mat	886	9,176	9,451
104	MAT/SUPP MAINT OF MAIN	887.45	Mat	887	31,010	31,940
105	MAT/SUP MAINT M&R STAT EQUIP	889.45	Mat	889	18,998	19,568
106	MAT/SUP MAINT M&R INDUST EQUIP	890.45	Mat	890	3,718	3,830
107	MAT/SUP MAINT CITY GATE STAT	891.45	Mat	891	3,323	7,616
108	MAT/SUP MAINT OF SERVICES	892.45	Mat	892	5,440	5,604
109	MAT/SUPP MAINT MTR & HSE REG	893.45	Mat	893	13,945	14,364
110						

WP2_C

Valley Energy, Inc. (PA)
Rate Case with Fully Projected Future Test Year 2026
Workpaper 2 to Schedule C
Future O&M
Years 2025 and 2026

Line	Dept.	Account	rType22	rAcct25	rFTY25 Total 2025	rFPFTY26 Total 2026
111	MAT/SUPP METER READING EXP	902.45	Mat	902	3,981	4,100
112	NISC BILLING	903.25	Other	903	111,397	112,891
113	MAT/SUP CUST REC/COLLECTIONS	903.45	Mat	903	29,837	30,732
114	DOLLAR ENERGY FUND EXPENSES	903.55	Other	903	5,927	5,927
115	BAD DEBT EXPENSE	904.00	Other	904	50,495	54,348
116	MAT/SUP MISC CUST ACCT EXP	905.45	Mat	905	21,492	21,492
117	INFORMATION/INSTRUCTIONAL EXP	909.45	Mat	909	12,774	13,157
118	ADVERTISING EXPENSES	913.45	Mat	913	2,057	2,098
119						
120	MAT/SUP ADMINISTRATIVE	920.45	Mat	920	68	69
121	GENERAL OFFICE SUPPLIES & EXP	921.00	Other	921	12,054	12,054
122	MEAL EXPENSES	921.40	Other	921	9,132	9,406
123	TRAVEL AND TRAINING	921.45	Other	921	40,834	42,059
124	COMMUNICATION EQUIP	921.50	Other	921	17,350	17,871
125	OUTSIDE SERVICES EMPLOYED	923.00	Other	923	25,452	26,215
126	AUDITOR FEES EXPENSE	923.25	Other	923	43,735	47,233
127	GCR EXPENSE	923.40	Other	923	3,321	3,487
128	ATTORNEY FEES EXPENSE	923.45	Other	923	8,152	8,560
129	INSURANCE ST OPENING BONDS	925.10	Other	925	500	376
130	PROPERTY INSURANCE EXPENSE	924.00	Other	924	36,257	41,699
131	INJURIES AND DAMAGES	925.00	Other	925	108,157	93,524
132	EMPLOYEE BENEFITS-DIRECT EXP.	926.45	Other	926	9,898	10,194
133	REGULATORY COMMISSION EXPENSES	928.00	Other	928	99,514	105,514
134	MISCELLANEOUS GENERAL EXPENSE	930.20	Other	930	28,363	30,751
135	LABOR - VOLUNTEER	930.21	Other	930	187	216
136	DUES/COMPANY MEMBERSHIPS	930.22	Other	930	16,791	17,295
137	COVID-Related	930CV	Other	930CV	-	-
138	DIRECTOR EXPENSE	930.25	Other	930	58,639	57,047
139	DIRECTOR EXP. - TRAVEL/TRAINING	930.45	Other	930	-	1,309
140	MAINT GENERAL PLANT	932.45	Mat	932	23,249	23,946
141	**Total Direct Expenses**				**1,059,219**	**1,077,423**
142					3,662,186	3,968,110
143					3,662,186	3,987,778
144					3,662,186	3,987,778
145						
146						
147			Other		781,570	794,837
148			Mat		277,649	282,586
149					1,059,219	1,077,423

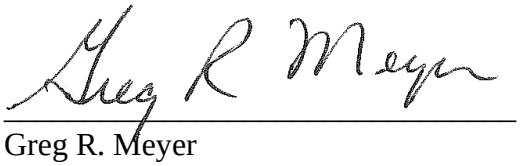
BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No. R-2025-3054393
	:	
Valley Energy, Inc.	:	

VERIFICATION

I, Greg R. Meyer, hereby state that the facts above set forth in my Rebuttal Testimony, OCA Statement 1-R, are true and correct to the best of my knowledge, information, and belief and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa.C.S. § 4904 (relating to unsworn falsification to authorities).

DATED: August 13, 2025

Signature: 

Greg R. Meyer

Address: Brubaker & Associates, Inc.
16690 Swingley Ridge Road, Suite 140
Chesterfield, MO 63017

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
v.	)	**R-2025-3054392**
Wellsboro Electric Company	)	

Rebuttal Testimony and Exhibit of

Greg R. Meyer

OCA Statement 1R

On behalf of

Pennsylvania Office of Consumer Advocate

Date Served: August 13, 2025

BRUBAKER & ASSOCIATES, INC.

Project 11858

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
v.	)	**R-2025-3054392**
Wellsboro Electric Company	)	

Table of Contents to the
Rebuttal Testimony of Greg R. Meyer

INCOME TAX RATE 3

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CONCLUSION 6

EXHIBIT GRM-R1 (WELLSBORO)

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
v.	)	**R-2025-3054392**
Wellsboro Electric Company	)	

Rebuttal Testimony of Greg R. Meyer

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Greg R. Meyer. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q WHAT IS YOUR OCCUPATION?

A I am a consultant in the field of public utility regulation and a Senior Principal with the firm of Brubaker & Associates, Inc. ("BAI"), energy, economic and regulatory consultants.

Q ARE YOU THE SAME GREG R. MEYER WHO PREVIOUSLY FILED DIRECT TESTIMONY ON JULY 15, 2025, IN THIS PROCEEDING?

A Yes, I am.

Q ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?

A I am appearing on behalf of the Pennsylvania Office of Consumer Advocate ("OCA").

Q PLEASE GIVE A BRIEF OVERVIEW OF YOUR REBUTTAL TESTIMONY.

A My Rebuttal Testimony will address certain issues that the OCA would support and the revenue requirement impact from those issues. I am not addressing all issues of agreement due to the value of the issues, but the OCA will support those adjustments in either settlement negotiations or at the rate case hearings.

My silence regarding any issue should not be construed as an endorsement of or acquiescence to positions advanced by Wellsboro Electric Company ("Wellsboro").

Q WHAT ADJUSTMENTS WILL YOU BE DISCUSSING IN YOUR REBUTTAL TESTIMONY?

A My Rebuttal Testimony will address the following issues:

- The adoption of the 2026 state income tax rate of 7.49%.
- The normalization versus amortization of rate case expense and rate base treatment.

Q HAVE YOU PREPARED EXHIBIT GRM-R1 (WELLSBORO) TO SHOW THE IMPACTS OF THESE TWO ISSUES ON THE OCA'S PROPOSED REVENUE REQUIREMENT?

A Yes. I have prepared Exhibit GRM-R1 (Wellsboro) that shows the revenue requirement impact from the two issues that the OCA is supporting.

Table GRM-R1 (Wellsboro)

OCA Revenue Requirement Adjustments

Line	Description	Amount
1	Company Proposed Revenue Requirement Increase[1]	$ 2,899,388
	OCA Adjustments:	
2	Return on Equity	$ (405,756)
3	Rate Revenue	$ (28,210)
4	Labor	$ (139,491)
5	Acct 920 and 932	$ (152,463)
6	Sponsorship and Lobbying	$ (2,389)
7	Credit Card Fee	$ 37,645
8	Income Tax Rate	$ (43,372)
9	Rate Case Reg Liability	$ (25,938)
10	Rate Case Normalization Period	$ (47,444)
11	Total OCA Adjustments	$ (807,419)
12	OCA Proposed Revenue Requirement Increase	$ 2,091,970

Source:
[1]OCA-I-1 Attachment A (Schedule A-D) Tab "C1."

INCOME TAX RATE

Q HAVE YOU READ THE DIRECT TESTIMONY OF THE OFFICE OF SMALL BUSINESS ADVOCATE ("OSBA") WITNESS JUSTIN FARR AND THE BUREAU OF INVESTIGATION AND ENFORCEMENT ("I&E") WITNESS ZACHARI WALKER ADDRESSING THE STATE INCOME TAX RATE?

A Yes, I have.

Q WHAT DO THESE WITNESSES PROPOSE TO USE FOR THE STATE INCOME TAX RATE?

A Both witnesses propose to use the state income tax rate of 7.49% which will be in effect in 2026.[1] Both witnesses discuss that on July 8, 2022, Pennsylvania House Bill 1342 was signed into law as Act 53 of 2022. Act 53 lowered the state corporate income tax rate over several years to a 4.99% state corporate tax rate effective in 2031.

Q DO YOU SUPPORT THIS POSITION?

A Yes, the 2026 state corporate tax rate of 7.49% should be used to calculate Wellsboro's revenue requirement. I have incorporated the 2026 state corporate tax rate (7.49%) in my revenue requirement calculation and reflected the impact on my Exhibit GRM-R1 (Wellsboro). The new corporate tax rate lowers Wellsboro's revenue requirement by $43,372. I would also note that this adjustment includes the reduction in the cash working capital balance required for this revenue requirement issue.

NORMALIZATION OF RATE CASE EXPENSES

Q HAVE YOU READ THE REBUTTAL TESTIMONY OF I&E WITNESS ZACHARI WALKER DISCUSSING RATE CASE EXPENSE?

A Yes, I have.

[1]Walker Direct Testimony (Wellsboro), I&E Statement 1, page 22.

Q PLEASE SUMMARIZE MR. WALKER'S POSITION.

A Mr. Walker supports normalizing rate case expense over the projected period of time that will occur between Wellsboro's rate cases. Mr. Walker argues correctly that rate case expense should be normalized instead of establishing an amortization period. Mr. Walker also recognizes that rate case expense is an operating expense that is incurred periodically. Normalizing this expense for equal recovery over a multi-year period is the proper ratemaking principle. I support normalizing rate case expense. I support Mr. Walker's five-year period for normalizing rate case expenses based on the Company's three recent rate case filing intervals.[2] This results in a ratemaking adjustment of $47,444.

Q WHAT RATEMAKING TREATMENT DID WELLSBORO PROPOSE?

A According to Mr. Walker, Wellsboro proposed to amortize rate case expense over a multi-year period. Given that Wellsboro chose to amortize rate case expense, it also is requesting rate base treatment for the unamortized rate case expense balance.

Q ARE YOU SUPPORTIVE OF INCLUDING THE UNAMORTIZED PORTION OF RATE CASE EXPENSE IN WELLSBORO'S RATE BASE?

A Absolutely not. Rate case expense is a normal operating expense of the utility. Normalizing the rate case expense recovery over a multi-year period is the proper method to collect these recurring, but not annual expenses. By including rate case expense in rate base, Wellsboro's shareholders would earn a profit on a normal and

[2]Walker Direct Testimony (Wellsboro), I&E Statement 1, page 10.

recuring expense item. I am opposed to enhancing the profits of Wellsboro's shareholders for the inclusion of rate case expense in rate base. Furthermore, rate cases also provide benefits for Wellsboro's shareholders. There is no need to reward shareholders further by allowing a profit return on those expenses.

Q WHAT IS THE REVENUE REQUIREMENT IMPACT FOR DISALLOWING RATE BASE TREATMENT OF RATE CASE EXPENSE?

A Removing the unamortized balance of rate case expense from Wellsboro's rate base would lower Wellsboro's revenue requirement by $25,938.

CONCLUSION

Q DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A Yes, it does.

Table GRM-R1 (Wellsboro)

OCA Revenue Requirement Adjustments

Line	Description	Amount
1	Company Proposed Revenue Requirement Increase[1]	$ 2,899,388
	OCA Adjustments:	
2	Return on Equity	$ (405,756)
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10	Rate Case Normalization Period	$ (47,444)
11	Total OCA Adjustments	$ (807,419)
12	OCA Proposed Revenue Requirement Increase	$ 2,091,970

Source:
[1]OCA-I-1 Attachment A (Schedule A-D) Tab "C1."

Wellsboro Electric Company

Change Log of OCA Adjustments to Revenue Requirement

Line	Issue	Changed Cells	Starting Revenue Requirement Increase	Ending Revenue Requirement Increase	OCA Adjustment	Notes and Sources
			(1)	(2)	(3)	(4)
1	Return on Equity	Changed Cell E13 on Tab "C1-2" to 9.5%	$ 2,899,388	$ 2,493,632	$ (405,756)	See Mr. Christopher Walters, OCA Statement 2
2	Rate Revenue - Commercial	On Tab "B3-1", added 101,281 to Cell F7, 134 to Cell G7, 621,892 to Cell H7, and 154 to Cell I7.	$ 2,493,632	$ 2,471,666	$ (21,967)	See Mr. Greg Meyer, OCA Statement 1; See Adjustment Schedule 1 for the calculation of additional usage added
3	Rate Revenue - Industrial	On Tab "B3-1", added 4,777,876 to Cell J7. Changed Cell J51 to reference Cell J7 instead of J52.	$ 2,471,666	$ 2,465,422	$ (6,243)	See Mr. Greg Meyer, OCA Statement 1; See Adjustment Schedule 1 for the calculation of additional usage added
4	Labor	On Tab "WP1_C", changed all Cells with values in Rows with Type of "Labor" from Account 580 to Account 932 to reflect a 4% increase in total labor for each year from 2024 in relation to their proportion of expense to the total in Row 206.	$ 2,465,422	$ 2,325,931	$ (139,491)	See Mr. Greg Meyer, OCA Statement 1
5	Account 920	Subtracted $81,880 from Cell U151 on Tab "WP1_C"	$ 2,325,931	$ 2,237,936	$ (87,995)	See Mr. Greg Meyer, OCA Statement 1
6	Account 932	On Tab "WP1_C", changed all Cells with values in Rows with Type of "OH" or "Other" from Account 932 to reflect a proportion of a $59,983 decrease in relation to their proportion of total Account 932 non-labor expense.	$ 2,237,936	$ 2,173,468	$ (64,468)	See Mr. Greg Meyer, OCA Statement 1
7	Sponsorship and Lobbying	Subtracted $32 from Cell I185 and $2,191 from Cell I144 on Tab "WP1_C"	$ 2,173,468	$ 2,171,079	$ (2,389)	See Mr. Greg Meyer, OCA Statement 1
8	Credit Card Fee	Added $35,029 from Cell I119 on Tab "WP1_C"	$ 2,171,079	$ 2,208,724	$ 37,645	See Ms. LeeAnn Wise, OCA Statement 4
9	Income Tax Rate	Changed Cell C26 on Tab "C1-4" to 7.49%	$ 2,208,724	$ 2,165,352	$ (43,372)	See https://www.pa.gov/agencies/revenue/resources/tax-rates/corporation-tax-rates for 2026 Tax Rate of 7.49%
10	Rate Case Reg Liability	Removed values from Cells F54 and G54 on Tab "C1-5"	$ 2,165,352	$ 2,139,414	$ (25,938)	See Mr. Greg Meyer, OCA Statement 1-R
11	Rate Case Normalization Period	Changed Cell G30 on Tab "C1-3" to 5.	$ 2,139,414	$ 2,091,970	$ (47,444)	See Mr. Greg Meyer, OCA Statement 1-R
12				OCA Total Adjustments	$ (807,419)	

Wellsboro Electric Company

Commercial Usage per Customer Adjustments

Line	Description	Sch 3 - NRS	Sch 3 - NRH	Sch 4 - CS	Sch 4 - CSH	Total
		(1)	(2)	(3)	(4)	(5)
1	Company Proposed FPFTY Sales (kWh)[1]	4,732,166	6,256	29,056,715	7,216	33,802,353
2	Company Proposed FPFTY Average Customers[1]	938	1	392	1	1,332
3	Company Proposed Usage per Customer (Line 1 ÷ Line 2)					25,377
4	OCA Proposed Usage per Customer[2]					25,920
5	OCA Adjustment to Usage per Customer (Line 4 - Line 3)					543
6	OCA Proposed Additional Usage[3]	101,281	134	621,892	154	723,461

Industrial Usage per Customer Adjustments

Line	Description	Sch 5 - IS
7	Company Proposed FPFTY Sales (kWh)[1]	26,746,293
8	Company Proposed FPFTY Average Customers[1]	13
9	Company Proposed Usage per Customer (Line 7 ÷ Line 8)	2,005,972
10	OCA Proposed Usage per Customer[2]	2,364,313
11	OCA Adjustment to Usage per Customer (Line 10 - Line 9)	358,341
12	OCA Proposed Additional Usage (Line 8 x Line 11)	4,777,876

Sources and Notes:

[1]Company Schedule B3-1.

[2]Ten year average of sales divided by average customers from 2020 to 2024 Annual Reports.

[3]Calculated based on the proportion of usage as shown on Company Schedule B3-1.

B3-1

Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026
Billing Units, Rates And Revenue At Present Rates
Fully Projected Future Test Year 2026

Line		Sch. 1- RS	Sch. 2- RSAE	Sch. 3- NRS	Sch. 3- NRH	Sch. 4- CS	Sch. 4- CSH	Sch. 5- IS	Sch. 6- MSL	Sch. 7- POL	Sch. 8- EU	Total
1						**BILLING UNITS**						
2	kWh Sales	44,812,773	397,781	4,833,447	6,390	29,678,607	7,370	31,524,169	0	0	102,572	111,363,111
3												
4	Number of Bills	61,910	350	11,258	12	4,704	12	160			48	78,454
5	Average Monthly Bills	5,159	29	938	1	392	1	13			4	6,538
6												
7						**Annual Billing Units- Public Lighting and Street Lighting, Fully Projected Future Test Year 2026**							
8	MV 20000 lumens											
9	LED 50 OH								1,788	5,064		6,852
10	LED 50 UG											
11	LED 50 UG Col											
12	LED 70 OH								1,307	4,381		5,688
13	LED 70 UG											
14	LED 140 OH									24		24
15	LED 140 UG											
16									3,095	9,469		12,564
17						**RATES AND CHARGES**						
18						**Tariff Rates**						
19	Customer Charge	$12.00	$12.00	$12.22	$12.22	$32.03	$45.81	$85.00				
20												
21	Energy Block 1	$0.05864	$0.05127	$0.07630	$0.08469	$0.02268	$0.06628	$0.02078	$10.76	$8.81	$0.08732	
22	Energy Block 2							$0.00130	$4.12	$8.33		
23									$11.06	$11.06		
24									$16.03	$16.03		
25									$4.69	$8.89		
26									$11.62	$11.62		
27									$5.81	$10.02		
28									$12.75	$12.75		
29												
30	Block 1 kWh = Demand X							130				
31	Demand Block 1					$6.60		$10.00				
32												
33						**COMPUTATION OF REVENUE**						
34	Customer Charge Revenue	742,920	4,200	137,573	147	150,669	550	13,600	0	0	0	1,049,658
35												
36	Distribution kWh Revenue	2,627,821	20,394	368,792	541	673,111	488	209,031	13,496	81,371	8,957	4,004,003
37	Distribution Demand Revenue					712,800		663,600				1,376,400
38	*Volumetric Distribution Reve.*	2,627,821	20,394	368,792	541	1,385,911	488	872,631	13,496	81,371	8,957	5,380,403
39	**Total Distribution Revenue**	$3,370,741	$24,594	$506,365	$688	$1,536,580	$1,038	$886,231	$13,496	$81,371	$8,957	$6,430,061
40		*3,357,674*	*24,303*	*490,178*		*1,507,523*		*880,700*				
41						**BILLING UNITS- DETAIL**						
42	Forecast Customers 2025	5,149	29	928	1	388	1	13			4	6,514
43	Customers added (lost)	10		10		4						24
44	Forecast Customers 2026	5,159	29	938	1	392	1	13	0	0	4	6,538
45	Block 1 kWh Sales	44,812,773	397,781	4,732,166	6,256	29,056,715	7,216	8,626,800	0	0	102,572	87,742,280
46	Block 2 kWh Sales							22,897,369				22,897,369
47								26,746,293				
48												
49												
50	From Sch B2-1											
51	Annual Use Per Customer	8,686	13,638	5,044	6,256	74,124	7,216	1,903,840			25,643	
52												
53	Block 1 kW Demand- Same as 2024					108,000		66,360				174,360
54												

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Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026

Net Operating Income And Rates of Return
HY 2024, FTY 2025 and FPFTY 2026
Answer to 52 Pa. Code 53.52 c[1]

Line	Description	HY 2024		Present Rates 12/31/2025	(A) Present Rates Fully Projected 12/31/2026	Proposed Rates Fully Projected 12/31/2026	(B) Proposed Rates Fully Projected 12/31/2020	(A)-(B) Change from Prior Order
		Per Books	Distribution Only	Distribution Only	Distribution Only	Distribution Only	Settlement Prior	
1	**REVENUE**							
2	Residential	$6,829,521	$3,190,200	$3,388,802	$3,395,335	$5,078,907	$3,261,637	$133,698
3	Commercial and industrial	5,657,570	2,642,167	2,887,490	2,930,902	4,126,437	2,708,336	222,567
4	Lighting	100,851	95,243	94,867	94,867	113,787	90,112	4,755
5	Sales for resale	17,863	8,957	8,957	8,957	12,171	9,732	(776)
6	Rounding						200	(200)
7	Electric operating revenue	12,605,805	5,936,568	6,380,115	6,430,061	8,522,031	6,070,017	360,044
8	Other revenue, net	318,497	318,497	320,653	327,777	327,777	116,459	211,318
9	Under (over) Collections	234,090	0	0	0	0	0	0
10	Total Revenue	13,158,392	6,255,065	6,700,768	6,757,838	8,849,808	6,186,476	571,362
11	*Annual kWH*	*97,019,287*	*97,019,287*	*104,333,284*	*111,363,111*	*111,363,111*	*107,825,923*	*(10,806,636)*
12	**EXPENSES**				Increase	2,091,970		
13	Purchased electricity	5,720,438						
14	Distribution	1,334,849	1,334,849	1,561,937	1,549,966	1,549,966	1,285,908	264,058
15	Customer accounting & collection expen	929,410	929,410	1,050,953	1,084,250	1,084,250	649,803	434,447
16	Sales expense, Public relations	3,171	3,171	19,727	7,531	7,531	8,915	(1,384)
17	Administrative & general expenses	1,264,200	1,264,200	1,486,637	1,408,255	1,408,255	929,641	478,614
18	Total Operating expenses	9,252,068	3,531,630	4,119,254	4,050,002	4,050,002	2,874,267	1,175,735
19								
20	Depreciation expense	1,335,247	1,335,247	1,844,192	1,939,404	1,939,404	1,331,977	607,427
21	Taxes other than income	814,557	394,406	420,575	423,522	594,586	377,878	45,644
22	Rate case expense amortization						108,667	(108,667)
23	Total Expenses	11,401,872	5,261,283	6,384,021	6,412,927	6,583,991	4,692,789	1,720,139
24								
25	Net operating income before income t	1,756,519	993,782	316,747	344,911	2,265,816	1,493,687	(1,148,776)
26								
27	Income tax expense	176,289	(29,018)	(45,510)	(37,259)	479,793	447,548	(484,808)
28	NET UTILITY OPERATING INCOME (LOSS) (A)	$1,580,230	$1,022,799	$362,256	$382,170	$1,786,023	$1,046,139	($663,969)
29						0.0699367		
30	RATE BASE (B)		$26,155,564	$25,884,748	$25,537,707	$25,537,707	$14,653,172	$11,502,392
31	RATE OF RETURN ON RATE BASE (A / B)		3.91%	1.40%	1.50%	6.99%	7.14%	

C1-2

Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026

Support Sheet No. 2- Summary of Cost of Capital and Fair Rate of Return Based upon a Hypothetical Ratemaking Capital Structure
12/31/2025 and 12/31/2026

Line	Type of Capital	Ratios (1)	Cost Rate		Weighted Cost Rate
1	Long-Term Debt	51.06%	4.850%		2.47641%
2	Short-Term Debt				0.00%
3	Total Debt	51.06%			2.48%
4					
5	Preferred Stock				0.00000%
6	Common Equity	48.94%	9.50%	9.2300%	4.64930%
7	Total	100.00%	9.31%		7.12571%
8				Target ROR	7.13%
9					
10	[1] Recommended hypothetical capital structure ratios as discussed in direct testimony.				
11					2,091,970

C1-3

Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026

Net Operating Income And Rates of Return
HY 2024, FTY 2025 and FPFTY 2026
Answer to 52 Pa. Code 53.52 c[1]
Support Sheet No. 3- Taxes Other Than Income

Line			HY 2024		Present Rates Year Ended 12/31/2025	Present Rates Future Test Year Ended 12/31/2026	Proposed Rates Future Test Year Ended 12/31/2026
			Per Books	Distribution Only	Distribution Only	Distribution Only	Distribution Only
1	Taxes other than income:						
2	Pennsylvania Use Tax		$837	$837	$837	$837	$837
3	PUC Assessment			0	0	0	0
4	Lease Tax		(10,663)				
5	Public Utility Realty Tax (including surcharge		43,311	43,311	43,311	43,311	43,311
6	Pennsylvania Gross Receipts Tax		781,072	350,258	376,427	379,374	550,438
7			$814,557	$394,406	$420,575	$423,522	$594,586
8							
9	**Gross Receipts Tax**						
10	Electric operating revenue		$12,605,805	$5,936,568	$6,380,115	$6,430,061	$9,329,449
11							
12							
13	Gross Receipts Taxable		$12,605,805	$5,936,568	$6,380,115	$6,430,061	$9,329,449
14	Gross Receipts Tax at Present Rate	5.90%	$743,742	$350,258	$376,427	$379,374	$550,438
15	Rounding difference		37,330				
16	Gross Receipts Tax expense		$781,072	$350,258	$376,427	$379,374	$550,438
17							
18	**Normalized Rate case expense**						
19	Estimated expenses					$331,178	
20	Amortization period (years)					5	
21	Normalized Rate case expense					$66,236	$66,236

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Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026

C1-4

Net Operating Income And Rates of Return
HY 2024, FTY 2025 and FPFTY 2026
Answer to 52 Pa. Code 53.52 c[1]
Support Sheet No. 4- Income Tax Calculations

Line	Description		HY 2024		Present Rates 12/31/2025	Present Rates Fully Projected 12/31/2026	Proposed Rates Fully Projected 12/31/2026
			Per Books	Distribution Only	Distribution Only	Distribution Only	Distribution Only
1	Net Operating Income Excluding Income Taxes		$1,756,519	$993,782	$316,747	$344,911	$2,265,816
2							
3	Synchronized interest expense:						
4	Rate base		26,155,564	26,155,564	25,884,748	25,537,707	25,537,707
5							
6	Rate base for interest compuation		26,155,564	26,155,564	25,884,748	25,537,707	25,537,707
7	Weighted Cost of debt		2.476%	2.476%	2.476%	2.476%	2.476%
8	Synchronized interest expense		647,719	647,719	641,012	632,418	632,418
9	Taxable income before depreciation tax adjustments		1,108,800	346,063	(324,266)	(287,508)	1,633,398
10							
11	Pennsylvania depreciation adjustment:						
12	Tax depreciation (using DDB method)		(2,466,799)	(2,466,799)	(2,176,619)	(2,195,614)	(2,195,614)
13	Book depreciation		1,335,247	1,335,247	1,844,192	1,939,404	1,939,404
14	Pennsylvania depreciation adjustment		(1,131,552)	(1,131,552)	(332,427)	(256,211)	(256,211)
15	Pennsylvania taxable income		(22,752)	(785,489)	(656,693)	(543,718)	1,377,187
16	Regulatory Pennsylvania income tax expense	7.49%	(1,704)	(58,833)	(49,186)	(40,725)	103,151
17							
18	Federal depreciation adjustment:						
19	Tax depreciation (using SL method)		(1,598,164)	(1,598,164)	(1,551,605)	(1,676,119)	(1,676,119)
20	Book depreciation		1,335,247	1,335,247	1,844,192	1,939,404	1,939,404
21	Federal depreciation adjustment		(262,917)	(262,917)	292,587	263,285	263,285
22							
23	Taxable income before depreciation tax adjustments		1,108,800	346,063	(324,266)	(287,508)	1,633,398
24	Federal depreciation adjustment		(262,917)	(262,917)	292,587	263,285	263,285
25	Pennsylvania income tax expense		1,704	58,833	49,186	40,725	(103,151)
26	Federal taxable income		847,587	141,979	17,508	16,502	1,793,532
27	Regulatory Federal income tax expense	21.00%	177,993	29,816	3,677	3,465	376,642
28							
29	Regulatory Total income tax expense		$176,289	($29,018)	($45,510)	($37,259)	$479,793
30							
31	Deferred Federal Income Tax expense (included in above):						
32	Tax depreciation (using SL method)		1,598,164	1,598,164	1,551,605	1,676,119	1,676,119
33	Tax depreciation (using DDB method)		2,466,799	2,466,799	2,176,619	2,195,614	2,195,614
34			868,635	868,635	625,014	519,496	519,496
35	Federal tax rate		21.00%	21.00%	21.00%	21.00%	21.00%
36	Deferred Federal income tax (credit)		$182,413	$182,413	$131,253	$109,094	$109,094
37	Combined statutory tax rate	26.92%					

Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026

Net Operating Income And Rates of Return
HY 2024, FTY 2025 and FPFTY 2026
Answer to 52 Pa. Code 53.52 c[1]
Support Sheet No. 5- Computation of Rate Base

Line	Description		HY 2024	FTY 2025	FPFTY 2026
1	**Utility Plant in Service**				
2	Assets	Sch. C3, line 23	$ 41,101,936	$ 42,831,436	$ 44,666,856
3	Less: Accumulated Depreciation	Sch. C3, line 23	(15,226,786)	(17,226,319)	(19,321,064)
4			25,875,150	25,605,116	25,345,792
5					
6	Less: Accumulated deferred income taxes (ADIT)	Line 32	96,455	19,318	(38,728)
7					
8	Less: Customer deposits	Sch. C2, line 52	(195,713)	(195,713)	(195,713)
9	Accrued Pension / OPEB Liability	Line 47	(303,994)	(303,994)	(303,994)
10	Materials & Supplies	Sch. C2, line 22	247,983	247,983	247,983
11			25,719,881	25,372,710	25,055,340
12	Cash Working Capital Allowance	Line 25	435,683	512,038	482,367
13	RATE BASE		$ 26,155,564	$ 25,884,748	$ 25,537,707
14					
15	**Cash Working Capital Allowance:**				
16	Operating Expenses	Sch. C1, line 23	$ 5,261,283	$ 6,384,021	$ 6,412,927
17					
18	Deductions:				
19	Taxes Oher Than Income	Sch. C1-3, line 7	420,575	423,522	594,586
20	Uncollectible accounts	Sch. C1-1, line 30	20,000	20,000	20,000
21	Depreciation Expense	Sch. C1, line 20	1,335,247	1,844,192	1,939,404
22	Total Deductions		1,775,822	2,287,714	2,553,989
23	Cash Operating Expenses		3,485,461	4,096,308	3,858,938
24	Cash Operating Expenses Ratio		1/8	1/8	1/8
25	Cash Working Capital Allowance (A plus B)		$ 435,683	$ 512,038	$ 482,367
26					
27	Regulatory Accumluated deferred income tax:				
28	Accumulated depreciation based on tax expense borne by ratepayers		26,630,508	28,182,113	29,858,231
29	Accumulated depreciation based on taxes paid by company		26,171,198	28,090,123	30,042,650
30	(Higher) depreciation taken by company		459,310	91,990	(184,419)
31	Federal tax rate		21.00%	21.00%	21.00%
32	Regulatory Accumluated deferred income tax (liability)		96,455	19,318	(38,728)
34	Excess deferred income tax:(EDIT)	NOT USED			
41					
42	Regulatoy (Liability) and Assets				
43	Accrued postretirement cost (Liability)		(185,579)	(185,579)	(185,579)
44	Regulatoy (Liability)		(230,379)	(230,379)	(230,379)
45	Regulatory Assets				
46	Deferred tax asset related to OPEB		111,964	111,964	111,964
47			(303,994)	(303,994)	(303,994)

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Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026
Expenses By Account and By Type
Year 2013, HY 2024, FTY 2025 and FPFTY 2026

Line	Account	#	Type	Annuals Totals, Detailed by Type 2023	2024	2025	2026	E&O 2025	Office 2025	Admin & Misc 2025	C&T Payroll 2025	Union Payroll 2025	Transportation 2025	E&O 2026	Office 2026	Admin & Misc 2026	C&T Payroll 2026	Union Payroll 2026	Transportation 2026	Annual Totals, By Account 2023	2024	2025	2026	Company Proposed E&O 2026	Office 2026	Admin & Misc 2026	C&T Payroll 2026	Union Payroll 2026	Transportation 2026
1	PPower-Power Purchases			8,108,800	6,587,193	7,834,837	9,111,330													8,108,800	6,587,193	7,834,837	9,111,330						
2	Total Power Purchased			8,108,800	6,587,193	7,834,837	9,111,330													8,108,800	6,587,193	7,834,837	9,111,330						
3																													
4	580.01-Oper Superv. Eng-Labor	580	Labor	-	4,043		-																						
5	580.02-Oper.Superv. Eng-OH	580	OH	-	4,078		-																						
6	580.03-Oper.Superv. Eng-Transp	580	Trans/Mat				-													-	8,121	-	-						
7	582.01-Station Exp-Labor	582	Labor				-																						
8	582.02-Station Exp-OH	582	Trans/Ma	-	-		-													-	-	-	-						
9	583.01-OH Line Exp-Labor	583	Labor	(2,379)	(1,766)	3,980	3,706					2,937	1,043					2,762	944									3,054	1,044
10	583.02-OH Line Exp-OH	583	OH	3,064	2,535	1,814	1,922					1,814						1,922											
11	583.05-OH Line Exp-Misc	583	Trans/Mat				-													686	770	5,794	5,628						
12	585.01-Street/Signal Light-Labor	585	Labor	-	127	178	165					131	47					123	42									136	46
13	585.02-Street/Signal Light-OH	585	OH	675	19	81	85					81						85											
14	585.04-Street/Signal Light-Matl	585	Trans/Mat				-													675	146	259	250						
15	586.01-Meter Exp-Labor	586	Labor	19,146	21,287	26,220	24,402	500			-	18,979	6,741	452			-	17,850	6,100					500			-	19,737	6,744
16	586.02-Meter Exp-OH	586	OH	14,498	15,697	11,725	12,422				-	11,725					-	12,422											
17	586.03-Meter Exp-Transp	586	Trans/Mat				-																						
18	586.05-Meter Exp-Misc	586	Other	-	-	500	500	500						500						33,644	36,983	38,445	37,324						
19	587.01-Cust Install Exp-Labor	587	Labor	-	109	178	165				-	131	47				-	123	42								-	136	46
20	587.02-Cust Install Exp-OH	587	OH	-	98	81	85				-	81					-	85											
21	587.04-Cust Install Exp-Matl	587	Trans/Mat				-													-	206	259	250						
22	588.00 Misc Distr Exps	588	Other	1,084	(1,388)	6,800	6,800	6,800						6,800															
23	588.01 Labor - Misc Distr Expens	588	Labor	37,840	29,489	61,875	57,895				34,092	20,501	7,282				32,024	19,282	6,589								35,409	21,320	7,285
24	588.02 OH - Misc Distr Exp	588	OH	48,793	40,264	62,211	62,486				49,545	12,666					49,068	13,418											
25	588.03-Misc Distr Exp-Transp	588	Trans/Mat				-																						
26	588.11 Labor - Gen'l Type Mfg - C	588	Labor	7,872	11,084	8,467	7,928				5,503	2,187	777				5,169	2,057	703								5,715	2,274	777
27	588.12 OH - Gen'l Type Mfg	588	OH	5,099	8,757	9,349	9,351				7,997	1,352					7,920	1,431											
28	588.13-Misc Dist Exp-Gen'l Mfg Ti	588	Trans/Mat				-																						
29	588.20-Misc Dist Exp-Outside Tra	588	Other	7,534	9,606	15,000	15,000	15,000						15,000															
30	588.21-Misc Dist Exp-Outside Tra	588	Labor	5,846	10,141	11,506	10,714				-	8,490	3,016				-	7,985	2,729								-	8,829	3,017
31	588.22-Misc Dist Exp-Outside Tra	588	OH	1,559	2,482	5,245	5,556				-	5,245					-	5,556											
32	588.23-Misc Dist Exp-Outside Tra	588	Trans/Ma	-	699		-																						
33	588.31 Labor - On Call - Standby	588	Labor	12,639	12,129	14,799	13,251					10,920	3,879					9,876	3,375									10,920	3,731
34	588.32-Misc Dist Exp-On Call Sta	588	OH	3,575	3,097	6,746	6,873					6,746						6,873											
35	588.40 Safety Mtgs & Training	588	Other	4,268	6,339		-																						
36	588.41 Labor - Safety Mtss & Tra	588	Labor	22,120	28,265	39,910	37,251				10,698	21,556	7,656				10,049	20,274	6,928								11,111	22,417	7,680
37	588.42 OH - Safety Mtgs & Trai	588	OH	12,442	12,981	38,515	39,156	9,650			15,547	13,318		9,650			15,397	14,109											
38	588.90 Misc Dist-Staking Dept-To	588	Other				-													170,671	173,944	280,422	272,260						
39	589.00-Distr rents	589	Other	30,717	32,950	35,300	35,300	35,300						35,300						30,717	32,950	35,300	35,300						
40																													
41	**Total operations**			236,392	253,121	360,478	351,012	67,750	-	-	123,381	138,860	30,487	67,702	-	-	119,627	136,233	27,450	236,392	253,121	360,478	351,012	500	-	-	52,236	88,823	30,352
42																													
43	590.01-Maint. Supv & Eng-Labor	590	Labor	37,403	41,204	41,076	38,585				41,076						38,585										42,663		
44	590.02-Maint. Supv & Eng-OH	590	OH	48,308	56,671	59,695	59,121				59,695						59,121												
45	590.03-Maint. Supv & Eng-Transp	590	Trans/Mat				-													85,710	97,875	100,771	97,706						
46	591.01-Maint of Structures-Labor	591	Labor	792	-		-																						
47	591.02-Maint of Structures-OH	591	Trans/Ma	1,056	-		-													1,848	-	-	-						
48	592.01-Maint of Station Equip-Lat	592	Labor	678	1,255	1,869	1,740					1,379	490					1,297	443									1,434	490
49	592.02-Maint of Station Equip-OH	592	OH	1,863	1,621	2,702	126,752	1,850				852		125,850				902											
50	592.03-Maint of Station Equip-Tra	592	Trans/Mat				-																						
51	592.04- Matl/Supp Inv-Maint Sta	592	Other				(110,119)							(110,119)															
52	592.11- Substation Inspect In-hou	592	Labor	3,156	334		-																						
53	592.00-Substation Insp-In House-	592	Other				-													5,697	3,210	4,571	18,373						
54	593.00 Maint OH Lines	593	Other				-																						
55	593.01 Labor - OH Line Maintenar	593	Labor	140,138	175,692	202,337	188,417					149,305	53,032					140,430	47,986									155,274	53,059
56	593.02 OH - OH Line Mainten	593	OH	126,049	129,933	101,742	107,224	9,500				92,242		9,500				97,724											
57	593.03-Maint of OH Lines-Transp	593	Trans/Mat				-																						
58	593.04 Matl/Supp Inv-Maint Ove	593	Trans/Ma	767	-		-																						
59	593.10 Maint OH Lines - Brush Cc	593	Other	407,770	444,468	480,457	480,457	480,457						480,457															
60	593.11 OH Line-Tree Trim-In-H	593	Labor	17,691	15,547	16,743	15,592					12,355	4,388					11,621	3,971									12,849	4,391
61	593.12-Tree Trim-In House-Trans	593	Trans/Mat			7,633	8,087					7,633						8,087											
62	593.13-Tree Trimming-In House-C	593	Labor				-																						
63	593.21-Overhead Line Inspection-	593	Trans/Ma	38,954	6,362	24,679	25,411				-	18,211	6,468				-	18,939	6,472										
64	593.22-OH Line Insp-Line Crew-C	593	OH	8,264	1,470	11,251	11,920				-	11,251					-	11,920											
65	593.30 Maint Of OH-Working Off	593	Other				-																						
66	593.31 Labor - Maint Lines - Worl	593	Labor	355	-		-																						
67	593.32 OH - Maint Lines - Work C	593	OH	(355)	-		-																						
68	593.40 Maint Of OH Lines - Meali	593	Other	919	359	1,500	1,500	1,500						1,500															
69	593.50-Maint O/H Line-Major Stor	593	Other	27,765	31,980		-																						
70	593.51 Labor - Maint Lines - Majo	593	Labor	30,707	26,331	53,377	49,169	20,000			-	24,629	8,748	18,088			-	23,165	7,916					20,000			-	25,614	8,753
71	593.52 OH Lines- Major	593	Other	6,092	4,524	15,216	16,120				-	15,216					-	16,120											
72	593.60 Maint Lines-Major Storm-I	593	Labor				-																						
73	593.80 Maint O/H - Testing-Tools	593	Other	24,438	26,984	40,500	40,500	40,500						40,500															
74	593.90 Maint-Special Equip-Repa	593	Other				-																						
75	593.91-Special Equip Insp-Labor	593	Labor	7,214	6,137	9,367	8,723					6,912	2,455					6,502	2,222									7,189	2,457
76	593.92-Special Equipment Inspect	593	Trans/Mat			4,270	4,524					4,270						4,524		836,769	869,788	969,072	957,644						
77	594.01-Maint of UG Lines-Labor	594	Labor	1,751	4,369	4,353	4,054				-	3,212	1,141				-	3,022	1,033								-	3,341	1,142
78	594.02-Maint of UG Lines-OH	594	OH	1,588	2,645	1,984	2,102				-	1,984					-	2,102											
79	594.03-Maint of UG Lines-Transp	594	Trans/Mat				-																						
80	594.04-Maint of UG Lines-Matl	594	Trans/Mat				-																						
81	594.05-Maint UG Lines- Misc	594	Other			-	-																						
82	594.11- UG Inspect In-hours	594	Labor	1,847	113	150	141					111	39					105	36									116	40
83	594.12- UG Inspect OH	594	OH			69	73					69						73											
84	594.90- Maint UG Lines PA ON	594	Other	23,250	23,079	33,500	33,500	33,500						33,500						28,436	30,206	40,056	39,870						
85	595.01-Maint of Line Xfrmrs-Labor	595	Labor	1,742	3,059	3,347	3,117					2,470	877					2,323	794									2,569	878
86	595.02-Maint of Line Xfrmrs-OH	595	OH	949	1,358	1,526	1,617					1,526						1,617											
87	595.03-Maint of Line Xfrmrs-Trans	595	Trans/Mat				-																						
88	595.05-Maint Line Xfrmrs-Misc	595	Other				-																						
89	595.80-Maint of Line Xfrmrs-Disp	595	Trans/Ma	2,987	10,115	3,000	3,000	3,000						3,000						5,677	14,532	7,873	7,734						
90	596.01-Maint of Street Lights-Lab	596	Labor	1,700	962	623	580					460	163					432	148									478	163
91	596.02-Maint of Street Lights-OH	596	OH	1,291	650	284	301					284						301											
92	596.04-Maint of Street Lights-Mat	596	Trans/Mat				-													2,991	1,612	907	881						
93	597.00-Maint of Meters	597	Labor	30,912	25,037		-																						
94	597.01-Maint of Meters-Labor	597	Labor	32,568	31,514	34,412	32,045					25,393	9,019					23,883	8,161									26,408	9,024
95	597.02-Maint of Meters-OH	597	OH	9,842	7,010	15,688	16,620					15,688						16,620											
96	597.03-Maint of Meters-Transp	597	Trans/Mat				-																						
97	597.04-Maint of Meters-Matl	597	Trans/Ma	(529)	8		-																						
98	597.05-Maint of Meters-Misc	597	Trans/Mat				-																						
99	597.41-Maintenance of Meters-TV	597	Labor			623	580					460	163					432	148									478	163
100	597.42-Maintenance of Meters-TI	597	OH			27,484	27,501	27,200				284		27,200				301											
101	597.44-Maint TWACS Meters	597	Other	2,674	937	-	-													75,467	64,505	78,208	76,746						
102																													
103	**Total Maint**			1,042,595	1,081,729	1,201,459	1,198,954	617,507	-	-	100,771	396,196	86,985	629,476	-	-	97,706	392,443	79,329	1,042,595	1,081,729	1,201,459	1,198,954	20,000	-	-	42,663	235,750	80,558
104																													
105	**Total Distr Exp**			1,278,988	1,334,849	1,561,937	1,549,966	685,257	-	-	224,153	535,056	117,471	697,179	-	-	217,333	528,676	106,779	1,278,988	1,334,849	1,561,937	1,549,966	20,500	-	-	94,899	324,573	110,910
106				-	-		-																						
107	**CustS ACCOUNTING & COLLECTING Exp**																												
108	902.01-Meter Reading Exp-Labor	902	Labor	10,767	12,359	10,936	10,184					8,070	2,866					7,591	2,594									8,393	2,868
109	902.02-Meter Reading Exp-OH	902	OH	9,042	9,416	4,986	5,283					4,986						5,283											
110	902.03-Meter Reading Exp-Trans	902	Trans/Mat				-													19,808	21,775	15,922	15,467						
111	903.00-Cust Rec & Col Exp	903	Other	5,411	6,868	5,000	5,000			5,000						5,000													
112	903.01-Cust Rec & Collect Exp-Li	903	Labor	201,641	203,082	215,355	208,407				213,345	1,483	527				206,535	1,395	477								228,366	1,543	527
113	903.02-Cust Rec & Collect Exp-O	903	OH	260,964	276,153	310,965	352,459				310,049	916					316,458	972											
114	903.03-Cust Rec & Collect Exp-Tr	903	Trans/Mat				-																						
115	903.29-Cust Rec Exp-Seminars-M	903	Other			500	500		500						500														
116	903.30-Cust Rec Exp-Postage	903	Other	40,256	43,390	43,375	43,375		43,375						43,375														
117	903.40-Cust Coll-Credit Check	903	Other	858	801	900	900		900						900														
118	903.45-Cust Coll-EGS Monthly Sy	903	Other	3,260	4,252	3,600	3,600		3,600						3,600														
119	903.50-Cust Rec Exp-Billing Supp	903	Other	496	1,153	3,200	3,200		3,200						3,200														
120	903.60-Cust Rec Exp-NISC Comp	903	Other	128,903	135,388	163,600	163,600	8,500	155,100					8,500	155,100														
121	903.81-Cust Rec Exp-Collect-Lab	903	Labor	69,880	70,302	75,899	73,379				73,281	1,932	686				70,942	1,817	621								78,440	2,009	686
122	903.82-Cust Rec Exp-Collectino-C	903	OH	88,320	92,349	107,690	109,963				106,497	1,193					108,698	1,265											
123	903.83-Cust Rec Exp-Collect-Trar	903	Trans/Mat				-																						
124	903.90-Cust Rec Exp-Delinq	903	Other			500	500		500						500														
125	903.91-Cust Rec Exp-Delino-Labo	903	Labor	36,011	36,526	39,266	37,573				27,351	8,792	3,123				26,478	8,269	2,826								29,277	9,143	3,124
126	903.92-Cust Rec Exp-Delinq-OH	903	OH	36,950	37,371	45,181	46,326				39,749	5,432					40,571	5,755											
127	903.05-Cust Rec Exp-Delinq-Misc	903	Other				-													872,949	907,634	1,015,031	1,048,782						
128	904.00-Uncollectable Accounts	904	Other	-	-	20,000	20,000		20,000						20,000					-	-	20,000	20,000						
129																													
130	**Total Cust accounting & collecting**			892,757	929,410	1,050,953	1,049,221	8,500	227,175	5,000	770,272	32,804	7,202	8,500	227,175	5,000	769,682	32,347	6,517	892,757	929,410	1,050,953	1,084,250	-	-	-	336,083	21,088	7,206
131						0																							
132	**SALES PROMOTION Exp**																												
133	908.00-Cust Assist-Exp	908	Other	295	-	1,000	1,000		1,000						1,000														
134	908.51-Cust Assist-Energy Audit-I	908	Labor	1,735	180	156	146					115	41					109	37									120	41
135	908.52-Cust Assist-Energy Audit-I	908	OH			71	76					71						76											
136	908.05-Cust Assist-Energy Audit-I	908	Other				-													2,030	180	1,227	1,222						
137	909.00-Cust Service Info-Misc	909	Other	314	800	16,000	6,000		16,000						6,000					314	800	16,000	6,000						

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Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026
Expenses By Account and By Type
Year 2013, HY 2024, FTY 2025 and FPFTY 2026

Line	Account	#	Type	Annuals Totals, Detailed by Type 2023	2024	2025	2026	E&O 2025	Office 2025	Admin & Misc 2025	C&T Payroll 2025	Union Payroll 2025	Transportation 2025	E&O 2026	Office 2026	Admin & Misc 2026	C&T Payroll 2026	Union Payroll 2026	Transportation 2026	Annual Totals, By Account 2023	2024	2025	2026	Company Proposed E&O 2026	Office 2026	Admin & Misc 2026	C&T Payroll 2026	Union Payroll 2026	Transportation 2026
138	913.00-Advertising Exp	913	Other	1,738	2,191	2,500	309		2,500						2,500					1,738	2,191	2,500	309						
139							-																						
140	**Total Sales Promotion Exp**			4,082	3,171	19,727	9,722	-	19,500	-	-	186	41	-	9,500	-	-	185	37	4,082	3,171	19,727	7,531	-	-	-	-	120	41
141							-																						
142	**ADMINISTRATIVE & Genl Exp**						-																						
143	920.00-A&G Salaries	920	Labor	22,250	11,954	9,000	8,140			9,000						8,140										9,000			
144	920.01-A&G Salaries-Labor	920	Labor	258,765	292,156	325,262	319,071				322,262		3,000				316,358	2,713									349,797		3,000
145	920.02-A&G Salaries-OH	920	OH	351,031	402,852	468,335	402,852				468,335						402,852												
146	920.03-A&G Salaries-Transp	920	Trans/Mat				-																						
147	920.40-A&G-President-CEO	920	Labor	5,377	6,176	12,000	10,853	12,000						10,853										12,000					
148	920.50-A&G-V-P Fin Adminis	920	Labor	8,392	26,510	17,600	13,586			17,600						13,586										15,000			
149	920.60-A&G-V-P Eng Oper	920	Labor	2,059	3,188	15,000	13,586	15,000						13,586										15,000					
150	920.70-A&G- Staff	920	Labor	4,766	15,985	22,700	20,530		22,700						20,530					652,639	757,901	869,897	788,577		22,700				
151	921.00-Off Supp & Exp	921	Other	9,054	12,730	11,540	11,540		5,540	6,000					5,540	6,000													
152	921.10-Off Supp & Exp-Utilities	921	Other	4,803	5,835	6,060	6,060			6,060						6,060													
153	921.40-Off Exp-Subs/Membership	921	Other	4,042	5,186	3,400	3,400		3,400						3,400														
154	921.50-Off Exp-Off Supp	921	Other	6,413	8,823	23,260	23,260		23,260						23,260														
155	921.60-Off Exp-WECO Telephone	921	Other	31,375	47,437	49,500	49,500	-		49,500				-		49,500													
156	921.70-Off Exp-Dissatch Telephe	921	Other	79,441	89,963	90,800	90,800	86,000		4,800				86,000		4,800													
157	921.90-Off Exp-Misc	921	Other	9,938	8,780	20,060	20,060		17,700	2,360					17,700	2,360													
158	921.99-Off Exp-Working Capital C	921	Other	(83,141)	(65,853)	(81,613)	(94,910)			(81,613)						(94,910)				61,925	112,900	123,007	109,710						
159	923.00-Outside Svc Empl	923	Other	26,301	24,421	29,325	29,325		3,925	25,400					3,925	25,400													
160	923.10-Outside Svc Empl-Auditors	923	Other	31,951	34,886	34,000	34,000			34,000						34,000													
161	923.20-Outside Svc Empl-Engineering	923	Other	75	610	5,000	5,000	5,000						5,000															
162	923.30-Outside Svc Empl-Attorney	923	Other	21,703	16,158	25,000	25,000			25,000						25,000													
163	923.99-Outside Services Employe	923	Other	7,859	61,040	61,200	61,200			61,200						61,200				87,889	137,115	154,525	154,525						
164	924.00-Property Insurance	924	Other	51,268	53,098	61,410	61,410			61,410						61,410				51,268	53,098	61,410	61,410						
165	925.00-Injuries & Damages	925	Other				-													-	-	-	-						
166	926.11-Employee Pen Ben-Health	926	OH	-	-		-																						
167	926.20-Empl Pen Ben-Postret He	926	OH				-																						
168	926.70-Employee Pen Ben-Life In	926	OH				-																						
169	926.99-Employee Pen Ben-SERP	926	OH				-													-	-	-	-						
170	928.00-Regulatory Commission Ex	928	Other	32,144	42,985	43,000	43,000			43,000						43,000													
171	928.01-Rate Case Exp	928	Other	36,222	-		66,236									66,236				68,366	42,985	43,000	109,236						
172	930.00-Directors Exp	930	Other	101,167	83,257	95,851	106,681			95,851						106,681													
173	930.11-Misc Gen Exp-GPS Mac	930	Other	-	-		-																						
174	930.20-Misc Gen Exp-GPS Mac	930	Labor	3,074	-	3,100	2,804	3,100						2,804										3,100					
175	930.21-Misc Gen Exp-GPS Map	930	Other				-																						
176	930.22-Misc Gen Exp-GPS Mapp	930	OH				-																						
177	930.24-Misc Gen Exp-GPS Mapp	930	Other				-																						
178	930.25-Misc Gen Exp-Covid Expe	930	Other	-	-		-																						
179	930.30-Misc Gen Exp- Misc	930	Other	1,113	1,147	800	768	800						800						105,355	84,404	99,751	110,252						
180	931.00-Rents	931	Other	2,442	3,611	2,200	2,200		2,200						2,200					2,442	3,611	2,200	2,200						
181	932.00-Maint of Genl Property	932	Other	48,827	40,021	86,976	43,790	11,500		75,476				5,790		38,000													
182	932.01-Maint of Genl Property-La	932	Labor	46,719	9,859	10,814	10,070					7,980	2,834					7,506	2,565									8,299	2,836
183	932.02-Maint of Genl Property-OH	932	OH			4,950	2,625					4,930						2,625											
184	932.10-Maint of Genl Property-Of	932	Other	11,518	6,205	11,000	5,538	11,000						5,538															
185	932.11-Maint Genl Proc-Off Bldg-	932	Labor	3,217	-		-																						
186	932.12-Maint Genl Prop-Off Bldg	932	OH				-																						
187	932.20-Maint Genl-Communicatio	932	Other	-	-	500	252	500						252															
188	932.21-Maint Genl-Comm Equip-L	932	Labor				-																						
189	932.22-Maint Genl-Comm Equip-C	932	OH				-																						
190	932.30-Maint Gen Property-Plant	932	Other	422	12,688	12,550	6,319	12,550			-			6,319			-												
191	932.31-Maint Gen Proc-Plant Bldi	932	Labor	630	1,505	1,564	1,457					1,154	410					1,086	371									1,201	410
192	932.32-Maint Gen Proc-Plant Bld	932	OH			713	381					713						381											
193	932.41-Maint Gen Proc-Aot Hous	932	Labor				-																						
194	932.42-Maint Gen Prop-Apt Hous	932	OH				-																						
195	932.70-Maint Gen Office Equip	932	Other	1,248	1,908	3,800	1,913		3,800						1,913														
196	932.05-Maint Genl Property- Misc	932	Other	-	-		-													112,580	72,186	132,847	72,345						
197						1,486,637	1,408,287	157,450	82,525	435,044	790,597	14,777	6,244	136,921	78,468	458,442	719,210	11,597	5,649					30,100	22,700	24,000	349,797	9,500	6,246
198	**Total Administrative & Genl Exp**			1,142,464	1,264,200	1,486,637	1,408,287	157,450	82,525	435,044	790,597	14,777	6,244	136,921	78,468	458,442	719,210	11,597	5,649	1,142,464	1,264,200	1,486,637	1,408,255	30,100	22,700	24,000	349,797	9,500	6,246
199	Detail, adjusted for WC Claim						0																						
200	**Total Operating Exp**			3,318,291	3,531,630	4,119,254	4,017,196	851,207	329,200	440,044	1,785,022	582,823	130,959	842,600	315,143	461,442	1,706,224	572,805	118,982	3,318,291	3,531,630	4,119,254	4,050,002	50,600	22,700	24,000	780,779	355,281	124,403
201	From OM			*3,318,291*	*3,531,630*	*4,119,254*	*4,232,740*													0	0	0	32,806						
202	Adjustments			r:\C\Users\hgorn\Documer	r:\C\Users\hgorn\Documents Laptop\CTE-2016\WS-2\[WS-2S WS- 2S Support\[WS12S OpBudget2025.xlsx]Assumptions Breakdown-All'!$G$57																								
203	Working Capital claim			83,141	65,853	81,613	94,910																						
204	Rate case Exp																												
205				3,401,431	3,597,484	4,200,867	4,112,106	851,207	329,200	440,044	1,785,022	582,823	130,959	842,600	315,143	461,442	1,706,224	572,805	118,982										
206	From OM																												
207	From C1-1			-	1,294,042																								
208	Difference			3,401,431	2,303,442																								
209																													
210																													
211	Labor		Labor	1,087,018	1,135,323	1,294,042	1,227,986	50,600	22,700	26,600	727,608	342,044	124,490	45,763	20,530	21,706	706,139	321,317	112,511										
212	OH		OH	1,033,810	1,109,508	1,301,063	1,411,131	48,200	-	-	1,057,414	195,449	-	172,200	-	-	1,000,085	203,817	-										
213	Trans/Mat		Trans/Ma	43,235	17,184	39,582	41,022	3,000	-	-	-	30,114	6,468	3,000	-	-	-	31,550	6,472										
214	Other		Other	1,154,228	1,269,615	1,484,587	1,369,883	749,407	306,500	413,444	-	15,216	-	621,637	294,613	439,737	-	16,120	-										
215	WC		WC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-										
216				3,318,291	3,531,630	4,119,254	4,050,002	851,207	329,200	440,044	1,785,022	582,823	130,959	842,600	315,143	461,442	1,706,224	572,805	118,982										

1,357,763 Company Proposed FPFTY Labor
1,335,323 Company 2024 Labor
1,227,966 OCA Proposed FPFTY Labor
(129,798) OCA Adjustment to Labor

120,805 Company Proposed Non-Labor Account 932
60,822 OCA Proposed Non-Labor Account 932
(59,983) OCA Adjustment to Account 932 Non-Labor Expense

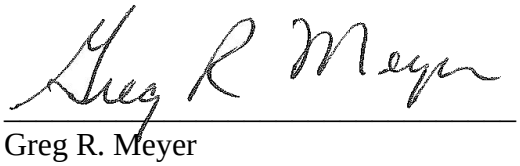
BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No. R-2025-3054392
	:	
Wellsboro Electric Company	:	

VERIFICATION

I, Greg R. Meyer, hereby state that the facts above set forth in my Rebuttal Testimony, OCA Statement 1R, are true and correct to the best of my knowledge, information, and belief and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa.C.S. § 4904 (relating to unsworn falsification to authorities).

DATED: August 13, 2025

Signature: 

Greg R. Meyer

Address: Brubaker & Associates, Inc.
16690 Swingley Ridge Road, Suite 140
Chesterfield, MO 63017

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
v.	)	**R-2025-3054394**
Citizens' Electric Company of Lewisburg, PA,	)	

Rebuttal Testimony of

Christopher C. Walters

OCA Statement 2R

On behalf of

Pennsylvania Office of Consumer Advocate

Date Served: August 13, 2025

BRUBAKER & ASSOCIATES, INC.

Project 11858

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
v.	)	**R-2025-3054394**
Citizens' Electric Company of Lewisburg, PA,	)	

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BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
v.	)	**R-2025-3054394**
Citizens' Electric Company of Lewisburg, PA,	)	

Rebuttal Testimony of Christopher C. Walters

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Christopher C. Walters. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q WHAT IS YOUR OCCUPATION?

A I am a consultant in the field of public utility regulation and a Principal with the firm of Brubaker & Associates, Inc. ("BAI"), energy, economic and regulatory consultants.

Q ARE YOU THE SAME CHRISTOPHER C. WALTERS WHO PREVIOUSLY FILED DIRECT TESTIMONY ON JULY 15, 2025, IN THIS PROCEEDING?

A Yes, I am.

Q ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?

A I am appearing on behalf of the Pennsylvania Office of Consumer Advocate ("OCA").

Q PLEASE GIVE A BRIEF OVERVIEW OF YOUR REBUTTAL TESTIMONY.

A The purpose of my Rebuttal Testimony in this proceeding is to address the recommendations relating to the recommended return on equity ("ROE") of 10.78% offered in the Direct Testimony of Bureau of Investigation & Enforcement ("I&E") witness Christopher Keller as well as the proxy ROE of 10.00% used in the testimony of Mr. Justin Farr on behalf of the Office of Small Business Advocate ("OSBA").

My silence on any particular issue should not be construed as tacit agreement or an endorsement of another party's position.

I. SUMMARY

Q PLEASE SUMMARIZE YOUR REBUTTAL TESTIMONY.

A My Rebuttal Testimony will discuss areas of disagreement with Mr. Keller and some of the errors that are present in Mr. Keller's analysis which have ultimately led him to his recommended ROE of 10.78%. I will demonstrate that Mr. Keller's recommendations are unsupported and, at times, are even contradicted by his own testimony. I conclude that Mr. Keller's recommended ROE and capital structure are excessive. Finally, I reiterate my recommendations including the Citizens' Electric Company of Lewisburg, PA ("Citizens" or "Company") be awarded an ROE of 9.50% and an equity ratio of 48.5%.

II. RESPONSE TO MR. KELLER

Q HAVE YOU REVIEWED MR. KELLER'S DIRECT TESTIMONY?

A Yes. Mr. Keller's Direct Testimony explains that he used a single constant growth Discounted Cash Flow ("DCF") model as his primary method to estimate Citizens' cost of common equity. He presents a Capital Asset Pricing Model ("CAPM") analysis but states that it is only a comparison and not part of his recommendation. Using a proxy group of electric utilities that operate in deregulated states, Mr. Keller calculated a spot dividend yield of roughly 4.04% and an average earnings growth rate of 6.92%. After he removes a 13.60% projected growth rate for Dominion Energy, his adjusted average growth rate is 6.74%. Applying these inputs in the constant growth DCF formula produced a recommended cost of equity of 10.78%. He then adopted Citizens' proposed capital structure and estimates that this 10.78% ROE yields an overall rate of return of about 7.76%.

Q IS THERE ANY OVERALL AGREEMENT BETWEEN YOU AND MR. KELLER?

A Yes. Both Mr. Keller and I reject several aspects of the Citizens' witness Mr. D'Ascendis' analysis. In particular, we agree that Mr. D'Ascendis' use of an Empirical CAPM ("ECAPM") is not a reasonable method for estimating ROE; that his proposed size-premium adjustment is inappropriate for regulated utilities because empirical evidence shows size premiums are not present in utilities; and that his management-performance adder (or "performance incentive") is not justified. We also

share concerns about the risk-free rate and market-risk premium assumptions embedded in Mr. D'Ascendis' CAPM.

Q PLEASE SUMMARIZE YOUR CONCERNS WITH MR. KELLER'S ANALYSIS AND RECOMMENDATIONS.

A My concerns with Mr. Keller's analysis are as follows:

- Similar to Mr. D'Ascendis, Mr. Keller's ROE recommendation of 10.78% would be the highest allowed ROE for an electric distribution utility since at least 2010.
- Mr. Keller's proxy group results and recommended ROE are severely disjointed from industry-wide norms for a distribution-only electric utility and even vertically integrated electric utilities and contradicts his own critique of inflated ROEs stemming from overreliance on CAPM and other market-based models; in my opinion, this shows error in his process of forming his opinion to recommend an ROE of 10.78%.
- Mr. Keller's constant growth DCF model is based on excessive growth rates, demonstrating error in judgment and necessitating the consideration of a multi-stage DCF model.
- Mr. Keller's recommended ROE is subject to significant biases and lacks thoroughness given his recommendation is based on the application of a single flawed model.

A. Mr. Keller's ROE Recommendation Exceeds Relevant Benchmarks

Q IS MR. KELLER'S RECOMMENDED ROE OF 10.78% CONSISTENT WITH RELEVANT BENCHMARKS?

A No. Mr. Keller's recommended ROE of 10.78% is inconsistent with and a deviation from all relevant benchmarks. According to compiled data from Regulatory Research Associates, a division of S&P Global, the average authorized ROE for electric distribution utilities since 2010 has not exceeded 10.0% in any given year during that

time. In Table CCW-1R, I have provided the annual average and maximum authorized ROE for each year since 2010 for both distribution and vertically integrated electric utilities.

TABLE CCW-1R

Historical Electric ROE Comparison

	Electric Distribution		Vertically Integrated	
Year	Average - %	Maximum - %	Average - %	Maximum - %
2010	9.98	10.30	10.42	11.90
2011	9.85	10.50	10.33	12.88
2012	9.75	10.40	10.10	10.50
2013	9.37	9.84	9.95	10.95
2014	9.49	9.75	9.94	10.40
2015	9.17	9.75	9.75	10.30
2016	9.31	9.90	9.77	10.55
2017	9.43	10.00	9.80	11.95
2018	9.38	10.00	9.68	10.00
2019	9.37	9.70	9.74	10.50
2020	9.10	9.70	9.55	10.02
2021	9.04	9.70	9.53	10.60
2022	9.11	10.00	9.75	10.80
2023	9.24	9.70	9.80	11.45
2024	9.53	9.76	9.84	10.50
2025	9.47	9.75	9.74	10.20
Annual Average	9.41	9.92	9.86	10.84

Source: Regulatory Research Associates.

Notably, since 2010, the annual average authorized ROE for distribution-only electric utilities has been roughly 9.41% and, in 2010, the average authorized ROE for electric distribution utilities was 9.98%, and that was the closest to 10.0% in recent history. Since 2023, the average authorized ROE for distribution-only electric utilities has ranged from 9.24% to 9.53%, and the year-to-date average in 2025 was just 9.47%. In fact, the highest authorized ROE to be awarded to a distribution-only electric utility

since 2010 was 10.50% awarded to Commonwealth Edison in Illinois in 2011 when the national average was 9.85% for electric distribution utilities.

Q DO YOU HAVE A RECOMMENDATION GIVEN THE ABOVE?

A Yes. Given that Mr. Keller's recommended 10.78% is far removed from any reasonable observable benchmark for an electric distribution utility like Citizens, I recommend that Mr. Keller's recommendation be rejected.

B. Mr. Keller's ROE Recommendation is Disjointed from Industry Norms

Q WHAT OTHER CONCERNS DO YOU HAVE AS IT RELATES TO MR. KELLER'S RECOMMENDED ROE OF 10.78%?

A Mr. Keller's recommended ROE of 10.78% is disconnected from prevailing industry norms, particularly for distribution-only electric utilities. While he attempts to account for deregulated market conditions by restricting his proxy group to companies operating in states with electric retail choice, his final ROE recommendation is inappropriately high for a distribution-only electric utility. In fact, Mr. Keller's 10.78% ROE would be the highest ROE awarded to a regulated electric distribution utility in the United States since at least 2010. As shown in Table CCW-1R, his recommendation even exceeds the average ROE authorized for vertically integrated electric utilities every year since at least 2010. Importantly, vertically integrated electric utilities are generally understood to face higher business and regulatory risks due to ownership of generation assets.

Q WHY IS IT PROBLEMATIC THAT MR. KELLER'S ROE EXCEEDS THOSE OF VERTICALLY INTEGRATED UTILITIES?

A Vertically integrated electric utilities are widely viewed as riskier than distribution-only utilities because they are exposed to fuel price volatility, environmental compliance costs, and capital-intensive generation investments. By contrast, distribution utilities operate with significantly lower business risk due to cost-of-service regulation and more predictable cash flows. An ROE for a distribution utility that exceeds the ROEs authorized for vertically integrated peers contradicts this fundamental risk distinction and suggests a flaw in the application or interpretation of Mr. Keller's modeling results.

Q DOES MR. KELLER'S ATTEMPT TO USE A DEREGULATED-ONLY PROXY GROUP JUSTIFY HIS HIGH ROE RECOMMENDATION?

A No. While Mr. Keller's effort to screen for deregulated utility companies may have been intended to better match the business risks faced by Citizens, the resulting 10.78% ROE cannot be reconciled with the actual decisions rendered by regulators nationwide for comparable electric distribution utilities. His recommended ROE of 10.78% is not only irregular in the context of recent ROE trends, but it also contradicts his own critique of inflated ROEs stemming from overreliance on CAPM and other market-based models. Indeed, despite claiming to rely primarily on the DCF model, Mr. Keller's recommended ROE reflects the upper end of estimates produced by models he himself characterizes as flawed or distorted in the current economic climate.

C. Mr. Keller's DCF Model is Based on Excessive Growth Rates

Q PLEASE SUMMARIZE MR. KELLER'S DCF MODEL.

A Mr. Keller performs a constant growth DCF analysis based on spot prices 52-week average as of May 14, 2025.[1] Mr. Keller assumes an average growth rate of 6.74% for his proxy group.[2] The indicated cost of equity for the spot stock price analysis is 10.77%, while the result for his 52-week stock price analysis is 10.79%. The midpoint of these two results is 10.78% and serve as the basis for his recommendation.[3]

Q PLEASE EXPLAIN THE SIMILARITIES BETWEEN YOUR CONSTANT GROWTH DCF ANALYSIS AND MR. KELLER'S CONSTANT GROWTH DCF ANALYSIS.

A Mr. Keller's proxy group growth rate (6.74%) is close to my proxy group's average growth rate of 6.87%. Our average constant growth DCF results are nearly identical.[4]

Q PLEASE SUMMARIZE YOUR PRIMARY CONCERN WITH MR. KELLER'S DCF ANALYSIS.

A My primary concern with Mr. Keller's DCF analysis is his assumed growth rate of 6.74% for his proxy group because it vastly exceeds the projected growth rate of the U.S. economy. As I discussed in my Direct Testimony, the consensus of research on the subject finds a utility's growth rate cannot exceed the growth rate of the economy

[1] I&E Exhibit No. 2, Schedule 7.
[2] *Id.*
[3] *Id.*
[4] The average constant growth DCF results presented in my Exhibit CCW-4 is 10.79%, or 1 basis point higher than Mr. Keller's average DCF result and ultimately his recommendation.

in which it provides services in perpetuity, which is the time period assumed by the DCF model. Given that Citizens provides distribution services in the United States, the projected long-term U.S. Gross Domestic Product ("GDP") growth rate is relevant.

Q WHAT IS THE PROJECTED LONG-TERM GROWTH RATE FOR THE U.S. ECONOMY?

A At the time of my analysis in my Direct Testimony, which is the same time of the analysis of Mr. Keller's Direct Testimony, the consensus for long-term GDP growth in the United States was 4.09%, which is 265 basis points lower than Mr. Keller's assumed average growth rate of 6.74% for his proxy group.

Q WHY IS THE GDP GROWTH PROJECTION A REASONABLE PROXY FOR THE MAXIMUM SUSTAINABLE LONG-TERM GROWTH RATE?

A The United State GDP growth projection is a reasonable upper limit, or proxy, for the maximum sustainable long-term growth rate in the DCF model because public utilities cannot indefinitely sustain a growth rate that exceeds the growth rate of the economy in which they sell services. A utilities' earnings and dividend growth are created by increased utility investment in its rate base. Examples of what can drive such investment are: service area economic growth, system reliability upgrades, or state and federal green energy initiatives. As such, the nominal U.S. GDP growth projection is a reasonable upper limit for utility sales growth, rate base growth, and earnings growth in the long-run.

Q DO YOU HAVE ANY FURTHER COMMENTS?

A Yes. Mr. Keller's use of a growth rate that is higher than the projected nominal U.S. GDP growth rate effectively says that Mr. Keller believes that utilities can indefinitely sustain a growth rate that exceeds the growth rate of the U.S. economy, in which the utility sells distribution services. However, Mr. Keller offers no explanation or data to show how a utility can indefinitely sustain a growth rate that exceeds the growth of the U.S. economy. Mr. Keller also fails to explain in his Direct Testimony what, if any, upper limit he would consider to be reasonable for his assumed growth rate for his proxy group. Given this flaw in his constant growth DCF analysis, it necessitates the consideration of a multi-stage DCF model to balance his result.

Q IS THE APPLICATION OF A MULTI-STAGE DCF MODEL USED IN PRACTICE?

A Yes. As I explained in my Direct Testimony, the multi-stage DCF model is widely used in practice. For example, the Chartered Financial Analyst ("CFA") Institute curriculum text states as follows:

> Multistage models are a staple valuation discipline of investment management firms using DCF valuation models.
>
> A survey of CFA Institute members with job responsibility for equity analysis indicates that, among respondents using a dividend discount model, two-stage and multistage models are used more often than the single-stage model (Stowe, Pinto, and Robinson 2018). Among analysts using a dividend discount model, 55% use a two-stage model, 11% use an H-model (a type of two-stage model), and 50% use a model with more than two stages (Stowe, Pinto, and Robinson 2018).[5]

[5]Chartered Financial Analyst Institute, 2023 CFA Program Level 2 Refresher Reading, Equity Valuation: Discounted Dividend Valuation, at page 30. [footnote omitted].

As Stowe *et al*. have revealed, the majority of equity analysts rely on multi-stage models more frequently than single-stage or constant growth models.

Q WHAT WOULD THE RESULTS OF A MULTI-STAGE DCF ANALYSIS BE BASED ON MR. KELLER'S INPUTS?

A Given Mr. Keller's proxy group growth rate (6.74%) is relatively close to my proxy group's average growth rate (6.87%), and our average constant growth DCF results are nearly identical,[6] the results of my multi-stage DCF analysis (8.62% and 8.39%) would be a close approximation.

Q HOW CAN THE MULTI-STAGE DCF ANALYSIS RESULT BE USED TO BALANCE THE RESULT OF MR. KELLER'S FLAWED DCF ANALYSIS?

A Assuming a multi-stage DCF result of 8.62%, the average of my multi-stage DCF analysis result and Mr. Keller's flawed constant growth DCF analysis results would be 9.7% [(10.78% + 8.62%) / 2]. This result is consistent with my recommended range 9.0% to 10.0%.

D. Mr. Keller's ROE Recommendation is Not Based on a Thorough Analysis

Q WHY IS MR. KELLER'S EXCLUSIVE RELIANCE ON A SINGLE CONSTANT-GROWTH DCF MODEL PROBLEMATIC?

A Although Mr. Keller claims to use the CAPM as a comparison of the results of his constant growth DCF analysis, Mr. Keller's exclusive reliance on the constant growth

[6]The average constant growth DCF results presented in my Exhibit CCW-4 is 10.79%, or 1 basis point higher than Mr. Keller's average DCF result and ultimately his recommendation.

DCF analysis is problematic because the cost of equity is not a directly observable figure; rather, it must be estimated using financial models that are based on assumptions and market expectations. No single model can be relied upon exclusively to estimate a fair and reasonable cost of equity because each model has its own strengths, limitations, and sensitivities to input assumptions. Mr. Keller's exclusive reliance on the constant growth DCF model is problematic because, other than being flawed, it ignores the insights that other well-established models, such as the sustainable growth DCF and multi-stage DCF analysis, or even the CAPM and the Risk Premium model, can provide.

By relying solely on a single model, Mr. Keller increases the risk of model-specific bias and fails to capture the full range of investor expectations. The constant growth DCF model, for instance, is highly sensitive to the assumed growth rate. As I discussed earlier in this testimony, Mr. Keller's analysis is flawed because it relies on growth rates that exceed the projected growth rate of the U.S. economy by a significant margin, which leads to inflated ROE estimates. Had Mr. Keller employed a multi-model approach, such as including a multi-stage DCF analysis, the CAPM and Risk Premium methods, all of which are widely used in regulatory proceedings, he could have cross-validated his constant growth DCF analysis results and mitigated the upward bias from his irregularly high growth assumptions.

Q WHY IS THE CONSIDERATION OF MULTIPLE MODELS IMPORTANT INFORMING AN UNBIASED OPINION?

A The consideration of multiple models is important in forming an unbiased opinion on a ROE recommendation because it is standard practice in the field of utility finance and

enhances the robustness and credibility of the resulting ROE recommendation. Ignoring these other models diminishes the reliability of Mr. Keller's recommendation and weakens the basis for his proposed ROE of 10.78%, which is well above national averages and recent Commission-authorized returns.

III. RESPONSE TO MR. FARR

Q HAVE YOU REVIEWED MR. FARR'S DIRECT TESTIMONY?

A Yes. Mr. Farr recommended several adjustments to Citizens' proposed revenue requirement. While he did not propose a specific total revenue requirement, Mr. Farr recommended a $269,644 reduction to Citizens' proposed $1.79 million increase. This reduction reflects his proposed use of a 10.00% proxy ROE, derived from the Pennsylvania Public Utility Commission's ("Commission") authorized ROE for Distribution System Improvement Charges ("DSIC"), even though he deferred a full ROE analysis to the OCA and I&E. Mr. Farr also opposed the Company's proposed 85-basis point size premium and 5-basis point performance adder, arguing that such upward adjustments are excessive and unsupported. He further recommended using the enacted 7.49% Pennsylvania corporate income tax rate for 2026 rather than the outdated 9.99% rate used by Citizens. Collectively, these adjustments would reduce the Company's requested rate increase from $1,794,525 to $1,524,881.

Q DO YOU AGREE WITH MR. FARR'S USE OF THE 10.00% DSIC ROE FROM THE COMMISSION'S QUARTERLY EARNINGS REPORT ("QER") AS A PROXY ROE IN THIS PROCEEDING?

A No, I do not agree with Mr. Farr's use of the 10.00% DSIC ROE from the Commission's QER as a proxy ROE for the Company. While Mr. Farr does not offer his own ROE recommendation, he assumes a 10.00% proxy ROE derived from the Commission's DSIC return published in its most recent QER. However, the Commission has expressly and repeatedly rejected the use of its DSIC ROE for purposes of establishing the cost of equity in base rate proceedings.

Q HAS THE COMMISSION ADDRESSED THIS ISSUE IN PRIOR CASES?

A Yes. In its May 8, 2025 Order in the Pike County Light & Power rate case (Docket Nos. R-2024-3052357 and R-2024-3052359), the Commission held that the DSIC ROE is "not relevant" to a base rate proceeding and distinguished it as an *industry-specific* figure determined quarterly, not a *company-specific* return derived from a fully developed evidentiary record. The Commission stated:

> We have previously found that the DSIC ROE is different from a ROE established in a base rate proceeding. We explained that the Commission determines the DSIC ROE on a quarterly basis and it is industry-specific, rather than a company-specific ROE set in a rate case.[7]

[7] *Pa. PUC v. Pike County Light & Power*, May 8, 2025 Order at page 28.

Q WHY IS MR. FARR'S RELIANCE ON THE DSIC ROE INAPPROPRIATE IN THIS CASE?

A Mr. Farr's opinion to use the DSIC ROE as a proxy ROE is unrelated to the Company's actual risks, financial structure, or cost of capital. He bypasses the entire cost of equity analysis process, including market-based models such as the DCF or CAPM, and relies instead on a figure that the Commission has determined is not suitable for use in base rate proceedings. As a result, the 10.00% proxy ROE Mr. Farr applies is arbitrary and flawed.

Q DOES MR. FARR PRESENT ANY INDEPENDENT ROE ANALYSES IN THIS PROCEEDING?

A No. Mr. Farr fails to present any independent ROE analyses in this proceeding. Instead, he explicitly defers to the analyses of the OCA and I&E, stating: "I do not have a recommendation for a specific ROE but rather defer to analysis and recommendations promulgated by the Office of Consumer Advocate ('OCA') and the Bureau of Investigation and Enforcement ('I&E')."[8]

As such, the OSBA has not independently developed a ROE recommendation and has not performed any market-based analyses to support its 10.00% proxy figure.

[8]OSBA St. No. 1 at page 10.

Q SHOULD MR. FARR'S DEFERRAL TO THE OCA'S OR I&E'S ROE ANALYSIS AND RECOMMENDED ROE BE GIVEN ANY WEIGHT?

A No. Mr. Farr's blind deferral to the OCA's or I&E's analyses and recommended ROE should be given no weight because he did not review or have knowledge about either my or I&E witness Keller's analyses and results prior to the submission of direct testimony. His blind deference to the OCA and I&E is arbitrary, containing no analysis or foundation.

Q SHOULD MR. FARR'S PROPOSED REVENUE REQUIREMENT REDUCTION BASED ON THE 10.00% ROE BE GIVEN ANY WEIGHT?

A No. Because Mr. Farr's proxy ROE is not grounded in a proper cost of equity analysis and is inconsistent with Commission precedent, the portion attributed to ROE of his proposed $269,644 downward adjustment to the Company's revenue requirement should be rejected.

IV. CONCLUSION

Q DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A Yes, it does.

542117

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No. R-2025-3054394
	:	R-2025-3054393
Citizens' Electric Company of Lewisburg, PA, Valley Energy, Inc., and Wellsboro Electric Company	:	R-2025-3054392

VERIFICATION

I, Christopher C. Walters, hereby state that the facts above set forth in my Rebuttal Testimony, OCA Statement No. 2R, are true and correct to the best of my knowledge, information, and belief and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa.C.S. § 4904 (relating to unsworn falsification to authorities).

DATED: August 13, 2025

Signature: */s/ Christopher C. Walters*
Christopher C. Walters

Address: Brubaker & Associates, Inc.
16690 Swingley Ridge Road
Suite 140
Chesterfield, MO 63017

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
v.	)	**R-2025-3054393**
Valley Energy, Inc.	)	

Rebuttal Testimony of

Christopher C. Walters

OCA Statement 2R

On behalf of

Pennsylvania Office of Consumer Advocate

Date Served: August 13, 2025

BRUBAKER & ASSOCIATES, INC.

Project 11858

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
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Rebuttal Testimony of Christopher C. Walters

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Christopher C. Walters. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q WHAT IS YOUR OCCUPATION?

A I am a consultant in the field of public utility regulation and a Principal with the firm of Brubaker & Associates, Inc. ("BAI"), energy, economic and regulatory consultants.

Q ARE YOU THE SAME CHRISTOPHER C. WALTERS WHO PREVIOUSLY FILED DIRECT TESTIMONY ON JULY 15, 2025, IN THIS PROCEEDING?

A Yes, I am.

Q ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?

A I am appearing on behalf of the Pennsylvania Office of Consumer Advocate ("OCA").

Q PLEASE GIVE A BRIEF OVERVIEW OF YOUR REBUTTAL TESTIMONY.

A The purpose of my Rebuttal Testimony in this proceeding is to address the recommendations relating to the recommended return on equity ("ROE") of 10.51% offered in the Direct Testimony of Bureau of Investigation & Enforcement ("I&E") witness D.C. Patel, as well as the proxy ROE of 10.15% used in the testimony of Mr. Justin Farr on behalf of the Office of Small Business Advocate ("OSBA").

My silence on any particular issue should not be construed as tacit agreement or an endorsement of another party's position.

I. SUMMARY

Q PLEASE SUMMARIZE YOUR REBUTTAL TESTIMONY.

A My Rebuttal Testimony will discuss areas of disagreement with Mr. Patel and some of the errors that are present in Mr. Patel's analysis which have ultimately led him to his recommended ROE of 10.51%. I will demonstrate that Mr. Patel's recommendations are unsupported and, at times, are even contradicted by his own testimony. I conclude that Mr. Patel's recommended ROE and capital structure are excessive and reiterate my recommendations including Valley Energy, Inc. ("Valley" or "Company") be awarded an ROE of 9.50% and an equity ratio of 48.5%.

II. RESPONSE TO MR. PATEL

Q HAVE YOU REVIEWED MR. PATEL'S DIRECT TESTIMONY?

A Yes. Mr. Patel's Direct Testimony explains that he used a single constant-growth Discounted Cash Flow ("DCF") model as his primary method to estimate Valley's cost

of common equity. He presents a Capital Asset Pricing Model ("CAPM") analysis but states that it is only a comparison and not part of his recommendation. Using a proxy group of gas utilities, Mr. Patel calculated a spot dividend yield of roughly 3.64% and an average earnings growth rate of 6.87%. Applying these inputs in the constant-growth DCF formula produced a recommended cost of equity of 10.51%. He then adopted Valley's proposed capital structure and estimates that this 10.51% ROE yields an overall rate of return of about 7.71%.

Q IS THERE ANY OVERALL AGREEMENT BETWEEN YOU AND MR. PATEL?

A Yes. Both Mr. Patel and I reject several aspects of the Valley witness Mr. D'Ascendis' analysis. In particular, we agree that Mr. D'Ascendis' use of an Empirical CAPM ("ECAPM") is not a reasonable method for estimating ROE; that his proposed size-premium adjustment is inappropriate for regulated utilities because empirical evidence shows size premiums are not present in utilities; and that his management-performance adder (or "performance incentive") is not justified. We also share concerns about the risk-free rate and market-risk premium assumptions embedded in Mr. D'Ascendis' CAPM.

Q PLEASE SUMMARIZE YOUR CONCERNS WITH MR. PATEL'S ANALYSIS AND RECOMMENDATIONS.

A My concerns with Mr. Patel's analysis are as follows:

- Similar to Mr. D'Ascendis, Mr. Patel's ROE recommendation of 10.51% would be the highest allowed ROE for a natural gas utility in the lower-48 since at least 2017.

- Mr. Patel's constant growth DCF model is based on excessive growth rates, demonstrating error in judgment and necessitating the consideration of a multi-stage DCF model.

- Mr. Patel's recommended ROE is subject to significant biases and lacks thoroughness given his recommendation is based on the application of a single flawed model.

A. Mr. Patel's ROE Recommendation Exceeds Relevant Benchmarks

Q IS MR. PATEL'S RECOMMENDED ROE OF 10.51% CONSISTENT WITH RELEVANT BENCHMARKS?

A No. Mr. Patel's recommended ROE of 10.51% is inconsistent with and a deviation from all relevant benchmarks. According to compiled data from Regulatory Research Associates, a division of S&P Global, the annual average authorized ROE for natural-gas utilities since 2024 has been roughly 9.70%, and only in 2010 did the industry-wide average briefly exceed 10%. In fact, since 2017 there has been only one gas-utility rate case in the lower-48 states with a ROE authorization above 10.5%. That case involved a 10.55% ROE for Atlanta Gas Light Company in 2017. Mr. Patel's 10.51% recommendation, therefore, sits at the very top of the observed range since then. In Table CCW-1R, I have provided the annual average and maximum authorized ROE for each year since 2010.

TABLE CCW-1R

Historical Authorized ROE Comparison

Year	Gas Distribution Average - %	Gas Distribution Maximum - %	Electric Distribution Average - %	Electric Distribution Maximum - %	Elec. Vert. Integrated Average - %	Elec. Vert. Integrated Maximum - %
2010	10.15	12.55	9.98	10.30	10.42	11.90
2011	9.91	10.50	9.85	10.50	10.33	12.88
2012	9.93	10.50	9.75	10.40	10.10	10.50
2013	9.68	10.25	9.37	9.84	9.95	10.95
2014	9.78	10.80	9.49	9.75	9.94	10.40
2015	9.60	10.30	9.17	9.75	9.75	10.30
2016	9.53	10.20	9.31	9.90	9.77	10.55
2017	9.73	11.88	9.43	10.00	9.80	11.95
2018	9.59	10.20	9.38	10.00	9.68	10.00
2019	9.73	10.25	9.37	9.70	9.74	10.50
2020	9.47	10.00	9.10	9.70	9.55	10.02
2021	9.56	10.24	9.04	9.70	9.53	10.60
2022	9.53	10.20	9.11	10.00	9.75	10.80
2023	9.60	10.50	9.24	9.70	9.80	11.45
2024	9.71	11.88	9.53	9.76	9.84	10.50
2025	9.72	9.90	9.47	9.75	9.74	10.20
Annual Average	9.70	10.63	9.41	9.92	9.86	10.84

Source: Regulatory Research Associates.
Note: The maximum gas ROEs for years 2010, 2017, and 2024 were set by single Alaska rate case decisions.

Importantly, the data shows that the highest average authorized ROE for gas utilities throughout the United States since 2010 was 10.15%. This data point is the only instance since 2010 where gas utility ROEs had an average in excess of 10.0%. Notably, even the highest average of 10.15% observed in 2010 is still 36 basis points below Mr. Patel's egregious recommendation.

Consequently, Mr. Patel's recommendation places Valley at the upper end of the spectrum and is inconsistent with industry norms.

Q DO YOU HAVE A RECOMMENDATION GIVEN THE ABOVE?

A Yes. Given that Mr. Patel's recommended 10.51% is far removed from any reasonable observable benchmark for a regulated gas distribution utility like Valley, I recommend that Mr. Patel's recommendation be rejected.

B. Mr. Patel's DCF Model is Based on Excessive Growth Rates

Q PLEASE SUMMARIZE MR. PATEL'S DCF MODEL.

A Mr. Patel performs a constant growth DCF analysis based on spot prices 52-week average as of May 28, 2025.[1] Mr. Patel assumes an average growth rate of 6.87% for his proxy group.[2] The indicated cost of equity for the spot stock price analysis is 10.39%, while the result for his 52-week stock price analysis is 10.62%. The midpoint of these two results is 10.51% and serve as the basis for his recommendation.[3]

Q PLEASE SUMMARIZE YOUR CONCERNS WITH MR. PATEL'S DCF ANALYSIS.

A My primary concern with Mr. Patel's DCF analysis is the assumed growth rate of 6.87%. As I discussed in my Direct Testimony, the consensus of research on the subject finds a utility's growth rate cannot exceed the growth rate of the economy in which it provides services in perpetuity, which is the time period assumed by the DCF model.

[1] I&E Exhibit No. 2, Schedule 6.
[2] *Id.*
[3] *Id.*

Q WHAT IS THE PROJECTED LONG-TERM GROWTH RATE FOR THE U.S. ECONOMY?

A At the time of my analysis in my Direct Testimony, which overlaps some of Mr. Patel's study period, the consensus for long-term GDP growth in the United States was 4.09%, a difference of 278 basis points relative to Mr. Patel's assumed average growth rate of 6.87% for his proxy group.

Q WHY IS THE GDP GROWTH PROJECTION A REASONABLE PROXY FOR THE MAXIMUM SUSTAINABLE LONG-TERM GROWTH RATE?

A The United State GDP growth projection is a reasonable upper limit, or proxy, for the maximum sustainable long-term growth rate in the DCF model because public utilities cannot indefinitely sustain a growth rate that exceeds the growth rate of the economy in which they sell services. A utilities' earnings and dividend growth are created by increased utility investment in its rate base. Examples of what can drive such investment are: service area economic growth, system reliability upgrades, or state and federal green energy initiatives. As such, the nominal U.S. GDP growth projection is a reasonable upper limit for utility sales growth, rate base growth, and earnings growth in the long-run.

Q DO YOU HAVE ANY FURTHER COMMENTS?

A Yes. Mr. Patel's use of a growth rate that is higher than the projected nominal U.S. GDP growth rate effectively says that Mr. Patel believes that utilities can indefinitely sustain a growth rate that exceeds the growth rate of the U.S. economy, in which the

utility sells distribution services. However, Mr. Patel offers no explanation or data to show how a utility can indefinitely sustain a growth rate that exceeds the growth of the U.S. economy. Mr. Patel also fails to explain in his Direct Testimony what, if any, upper limit he would consider to be reasonable for his assumed growth rate for his proxy group. Given this flaw in his constant growth DCF analysis, it necessitates the consideration of a multi-stage DCF model to balance his result.

Q IS THE APPLICATION OF A MULTI-STAGE DCF MODEL USED IN PRACTICE?

A Yes. As I explained in my Direct Testimony, the multi-stage DCF model is widely used in practice. For example, the Chartered Financial Analyst ("CFA") Institute curriculum text states as follows:

> Multistage models are a staple valuation discipline of investment management firms using DCF valuation models.
>
> A survey of CFA Institute members with job responsibility for equity analysis indicates that, among respondents using a dividend discount model, two-stage and multistage models are used more often than the single-stage model (Stowe, Pinto, and Robinson 2018). Among analysts using a dividend discount model, 55% use a two-stage model, 11% use an H-model (a type of two-stage model), and 50% use a model with more than two stages (Stowe, Pinto, and Robinson 2018).[4]

As Stowe *et al*. have revealed, the majority of equity analysts rely on multi-stage models more frequently than single-stage or constant growth models.

[4]Chartered Financial Analyst Institute, 2023 CFA Program Level 2 Refresher Reading, Equity Valuation: Discounted Dividend Valuation, at page 30. [footnote omitted].

Q WHAT WOULD THE RESULTS OF A MULTI-STAGE DCF ANALYSIS BE BASED ON MR. PATEL'S INPUTS?

A Given Mr. Patel's proxy group growth rate (6.87%) is identical to my proxy group's average growth rate, and our constant growth DCF results are relatively close,[5] the results of my multi-stage DCF analysis (8.62% and 8.39%) would be a close approximation.

Q HOW CAN THE MULTI-STAGE DCF ANALYSIS RESULT BE USED TO BALANCE THE RESULT OF MR. PATEL'S FLAWED DCF ANALYSIS?

A Assuming a multi-stage DCF result of 8.62%, the average of the collective DCF analyses would be 9.57% [(10.51% + 8.62%) / 2]. This result is consistent with my recommended ROE of 9.5%.

C. Mr. Patel's ROE Recommendation is not Based on a Thorough Analysis

Q WHY IS MR. PATEL'S EXCLUSIVE RELIANCE ON A SINGLE CONSTANT-GROWTH DCF MODEL PROBLEMATIC?

A Although Mr. Patel claims to use the CAPM as a comparison of the results of his constant growth DCF analysis, Mr. Patel's exclusive reliance on the constant growth DCF analysis is problematic because the cost of equity is not a directly observable figure; rather, it must be estimated using financial models that are based on assumptions and market expectations. No single model can be relied upon exclusively to estimate a

[5]The average and median constant growth DCF results presented in my Exhibit CCW-4 are 10.79% and 10.31%, respectively. The midpoint of those two numbers is 10.55%, or 4 basis points higher than Mr. Patel's average DCF result and ultimately his recommendation.

fair and reasonable cost of equity because each model has its own strengths, limitations, and sensitivities to input assumptions. Mr. Patel's exclusive reliance on the constant-growth DCF model is problematic because, other than being flawed, it ignores the insights that other well-established models, such as the sustainable growth DCF and multi-stage DCF analysis, or even the CAPM and the Risk Premium model, can provide.

By relying solely on a single model, Mr. Patel increases the risk of model-specific bias and fails to capture the full range of investor expectations. The constant growth DCF model, for instance, is highly sensitive to the assumed growth rate. As I discussed earlier in this testimony, Mr. Patel's analysis is flawed because it relies on growth rates that exceed the projected growth rate of the U.S. economy by a significant margin, which leads to inflated ROE estimates. Had Mr. Patel employed a multi-model approach, such as including a multi-stage DCF analysis, the CAPM and Risk Premium methods, all of which are widely used in regulatory proceedings, he could have cross-validated his constant growth DCF analysis results and mitigated the upward bias from his irregularly high growth assumptions.

Q HOW CAN THE MULTI-STAGE DCF ANALYSIS RESULT BE USED TO BALANCE THE RESULT OF MR. PATEL'S FLAWED DCF ANALYSIS?

A The consideration of multiple models is important in forming an unbiased opinion on a ROE recommendation because it is standard practice in the field of utility finance and enhances the robustness and credibility of the resulting ROE recommendation. Ignoring these other models diminishes the reliability of Mr. Patel's recommendation and weakens the basis for his proposed ROE of 10.51%, which is well above national

averages and recent Pennsylvania Public Utility Commission ("Commission") authorized returns.

III. RESPONSE TO MR. FARR

Q HAVE YOU REVIEWED MR. FARR'S DIRECT TESTIMONY?

A Yes. Mr. Farr recommended several adjustments to Valley's proposed revenue requirement. While he did not propose a specific total revenue requirement, Mr. Farr recommended a $286,940 reduction to Valley's proposed $1.6 million increase. This reduction reflects his proposed use of a 10.15% proxy ROE, derived from the Commission's authorized ROE for Distribution System Improvement Charges ("DSIC"), even though he deferred a full ROE analysis to the OCA and I&E. Mr. Farr also opposed the Company's proposed 100-basis point size premium and 5-basis point performance adder, arguing that such upward adjustments are excessive and unsupported. He further recommended using the enacted 7.49% Pennsylvania corporate income tax rate for 2026 rather than the outdated 9.99% rate used by Valley. Collectively, these adjustments would reduce the Company's requested rate increase from $1,626,099 to $1,339,159.

Q DO YOU AGREE WITH MR. FARR'S USE OF THE 10.15% DSIC ROE FROM THE COMMISSION'S QUARTERLY EARNINGS REPORT ("QER") AS A PROXY ROE IN THIS PROCEEDING?

A No, I do not. While Mr. Farr does not offer his own ROE recommendation, he assumes a 10.15% proxy ROE derived from the Commission's DSIC return published in its most

recent QER. However, the Commission has expressly and repeatedly rejected the use of its DSIC ROE for purposes of establishing the cost of equity in base rate proceedings.

Q HAS THE COMMISSION ADDRESSED THIS ISSUE IN PRIOR CASES?

A Yes. In its May 8, 2025 Order in the Pike County Light & Power rate case (Docket Nos. R-2024-3052357 and R-2024-3052359), the Commission held that the DSIC ROE is "not relevant" to a base rate proceeding and distinguished it as an *industry-specific* figure determined quarterly, not a *company-specific* return derived from a fully developed evidentiary record. The Commission stated:

> We have previously found that the DSIC ROE is different from a ROE established in a base rate proceeding. We explained that the Commission determines the DSIC ROE on a quarterly basis and it is industry-specific, rather than a company-specific ROE set in a rate case.[6]

Q WHY IS MR. FARR'S RELIANCE ON THE DSIC ROE INAPPROPRIATE IN THIS CASE?

A Mr. Farr's use of the DSIC ROE as a proxy introduces into evidence an ROE that is unrelated to the Company's actual risks, financial structure, or cost of capital. He bypasses the entire cost of equity analysis process, including market-based models such as the DCF or CAPM, and relies instead on a figure the Commission has determined is not suitable for use in base rate proceedings. As a result, the 10.15% proxy ROE Mr. Farr applies is arbitrary and unsupported by record evidence in this case.

[6] *Pa. PUC v. Pike County Light & Power*, May 8, 2025 Order at page 28.

Q DOES MR. FARR PRESENT ANY INDEPENDENT ROE ANALYSES IN THIS PROCEEDING?

A No. Mr. Farr explicitly defers to the analyses of the OCA and I&E, stating: "I do not have a recommendation for a specific ROE but rather defer to analysis and recommendations promulgated by the Office of Consumer Advocate ('OCA') and the Bureau of Investigation and Enforcement ('I&E')."[7]

As such, the OSBA has not independently developed a ROE recommendation and has not performed any market-based analyses to support its 10.15% proxy figure.

Q SHOULD MR. FARR'S PROPOSED REVENUE REQUIREMENT REDUCTION BASED ON THE 10.15% ROE BE GIVEN ANY WEIGHT?

A No. Because Mr. Farr's proxy ROE is not grounded in a proper cost of equity analysis and is inconsistent with Commission precedent, his proposed $185,644 downward adjustment to the Company's revenue requirement should be rejected in its entirety.

IV. CONCLUSION

Q DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A Yes, it does.

[7]OSBA St. No. 1 at page 10.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No. R-2025-3054394
	:	R-2025-3054393
Citizens' Electric Company of Lewisburg, PA, Valley Energy, Inc., and Wellsboro Electric Company	:	R-2025-3054392

VERIFICATION

I, Christopher C. Walters, hereby state that the facts above set forth in my Rebuttal Testimony, OCA Statement No. 2R, are true and correct to the best of my knowledge, information, and belief and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa.C.S. § 4904 (relating to unsworn falsification to authorities).

DATED: August 13, 2025

Signature: */s/ Christopher C. Walters*
Christopher C. Walters

Address: Brubaker & Associates, Inc.
16690 Swingley Ridge Road
Suite 140
Chesterfield, MO 63017

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Q ARE YOU THE SAME CHRISTOPHER C. WALTERS WHO PREVIOUSLY FILED DIRECT TESTIMONY ON JULY 15, 2025, IN THIS PROCEEDING?

A Yes, I am.

Q ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?

A I am appearing on behalf of the Pennsylvania Office of Consumer Advocate ("OCA").

Q PLEASE GIVE A BRIEF OVERVIEW OF YOUR REBUTTAL TESTIMONY.

A The purpose of my Rebuttal Testimony in this proceeding is to address the recommendations relating to the recommended return on equity ("ROE") of 10.78% offered in the Direct Testimony of Bureau of Investigation & Enforcement ("I&E") witness Christopher Keller as well as the proxy ROE of 10.00% used in the testimony of Mr. Justin Farr on behalf of the Office of Small Business Advocate ("OSBA").

My silence on any particular issue should not be construed as tacit agreement or an endorsement of another party's position.

I. SUMMARY

Q PLEASE SUMMARIZE YOUR REBUTTAL TESTIMONY.

A My Rebuttal Testimony will discuss areas of disagreement with Mr. Keller and some of the errors that are present in Mr. Keller's analysis which have ultimately led him to his recommended ROE of 10.78%. I will demonstrate that Mr. Keller's recommendations are unsupported and, at times, are even contradicted by his own testimony. I conclude that Mr. Keller's recommended ROE and capital structure are excessive. Finally, I reiterate my recommendations including the Wellsboro Electric Company ("Wellsboro" or "Company") be awarded an ROE of 9.50% and an equity ratio of 48.5%.

II. RESPONSE TO MR. KELLER

Q HAVE YOU REVIEWED MR. KELLER'S DIRECT TESTIMONY?

A Yes. Mr. Keller's Direct Testimony explains that he used a single constant growth Discounted Cash Flow ("DCF") model as his primary method to estimate Wellsboro's

cost of common equity. He presents a Capital Asset Pricing Model ("CAPM") analysis but states that it is only a comparison and not part of his recommendation. Using a proxy group of electric utilities that operate in deregulated states, Mr. Keller calculated a spot dividend yield of roughly 4.04% and an average earnings growth rate of 6.92%. After he removes a 13.60% projected growth rate for Dominion Energy, his adjusted average growth rate is 6.74%. Applying these inputs in the constant growth DCF formula produced a recommended cost of equity of 10.78%. He then adopted Wellsboro's proposed capital structure and estimates that this 10.78% ROE yields an overall rate of return of about 7.76%.

Q IS THERE ANY OVERALL AGREEMENT BETWEEN YOU AND MR. KELLER?

A Yes. Both Mr. Keller and I reject several aspects of the Wellsboro's witness Mr. D'Ascendis' analysis. In particular, we agree that Mr. D'Ascendis' use of an Empirical CAPM ("ECAPM") is not a reasonable method for estimating ROE; that his proposed size-premium adjustment is inappropriate for regulated utilities because empirical evidence shows size premiums are not present in utilities; and that his management-performance adder (or "performance incentive") is not justified. We also share concerns about the risk-free rate and market-risk premium assumptions embedded in Mr. D'Ascendis' CAPM.

Q PLEASE SUMMARIZE YOUR CONCERNS WITH MR. KELLER'S ANALYSIS AND RECOMMENDATIONS.

A My concerns with Mr. Keller's analysis are as follows:

- Similar to Mr. D'Ascendis, Mr. Keller's ROE recommendation of 10.78% would be the highest allowed ROE for an electric distribution utility since at least 2010.

- Mr. Keller's proxy group results and recommended ROE are severely disjointed from industry-wide norms for a distribution-only electric utility and even vertically integrated electric utilities and contradicts his own critique of inflated ROEs stemming from overreliance on CAPM and other market-based models; in my opinion, this shows error in his process of forming his opinion to recommend an ROE of 10.78%.

- Mr. Keller's constant growth DCF model is based on excessive growth rates, demonstrating error in judgment and necessitating the consideration of a multi-stage DCF model.

- Mr. Keller's recommended ROE is subject to significant biases and lacks thoroughness given his recommendation is based on the application of a single flawed model.

A. Mr. Keller's ROE Recommendation Exceeds Relevant Benchmarks

Q IS MR. KELLER'S RECOMMENDED ROE OF 10.78% CONSISTENT WITH RELEVANT BENCHMARKS?

A No. Mr. Keller's recommended ROE of 10.78% is inconsistent with and a deviation from all relevant benchmarks. According to compiled data from Regulatory Research Associates, a division of S&P Global, the average authorized ROE for electric distribution utilities since 2010 has not exceeded 10.0% in any given year during that time. In Table CCW-1R, I have provided the annual average and maximum authorized ROE for each year since 2010 for both distribution and vertically integrated electric utilities.

TABLE CCW-1R

Historical Electric ROE Comparison

	Electric Distribution		Vertically Integrated	
Year	Average - %	Maximum - %	Average - %	Maximum - %
2010	9.98	10.30	10.42	11.90
2011	9.85	10.50	10.33	12.88
2012	9.75	10.40	10.10	10.50
2013	9.37	9.84	9.95	10.95
2014	9.49	9.75	9.94	10.40
2015	9.17	9.75	9.75	10.30
2016	9.31	9.90	9.77	10.55
2017	9.43	10.00	9.80	11.95
2018	9.38	10.00	9.68	10.00
2019	9.37	9.70	9.74	10.50
2020	9.10	9.70	9.55	10.02
2021	9.04	9.70	9.53	10.60
2022	9.11	10.00	9.75	10.80
2023	9.24	9.70	9.80	11.45
2024	9.53	9.76	9.84	10.50
2025	9.47	9.75	9.74	10.20
Annual Average	9.41	9.92	9.86	10.84

Source: Regulatory Research Associates.

Notably, since 2010, the annual average authorized ROE for distribution-only electric utilities has been roughly 9.41% and, in 2010, the average authorized ROE for electric distribution utilities was 9.98%, and that was the closest to 10.0% in recent history. Since 2023, the average authorized ROE for distribution-only electric utilities has ranged from 9.24% to 9.53%, and the year-to-date average in 2025 was just 9.47%. In fact, the highest authorized ROE to be awarded to a distribution-only electric utility since 2010 was 10.50% awarded to Commonwealth Edison in Illinois in 2011 when the national average was 9.85% for electric distribution utilities.

Q DO YOU HAVE A RECOMMENDATION GIVEN THE ABOVE?

A Yes. Given that Mr. Keller's recommended 10.78% is far removed from any reasonable observable benchmark for an electric distribution utility like Wellsboro, I recommend that Mr. Keller's recommendation be rejected.

B. Mr. Keller's ROE Recommendation is Disjointed from Industry Norms

Q WHAT OTHER CONCERNS DO YOU HAVE AS IT RELATES TO MR. KELLER'S RECOMMENDED ROE OF 10.78%?

A Mr. Keller's recommended ROE of 10.78% is disconnected from prevailing industry norms, particularly for distribution-only electric utilities. While he attempts to account for deregulated market conditions by restricting his proxy group to companies operating in states with electric retail choice, his final ROE recommendation is inappropriately high for a distribution-only electric utility. In fact, Mr. Keller's 10.78% ROE would be the highest ROE awarded to a regulated electric distribution utility in the United States since at least 2010. As shown in Table CCW-1R, his recommendation even exceeds the average ROE authorized for vertically integrated electric utilities every year since at least 2010. Importantly, vertically integrated electric utilities are generally understood to face higher business and regulatory risks due to ownership of generation assets.

Q WHY IS IT PROBLEMATIC THAT MR. KELLER'S ROE EXCEEDS THOSE OF VERTICALLY INTEGRATED UTILITIES?

A Vertically integrated electric utilities are widely viewed as riskier than distribution-only utilities because they are exposed to fuel price volatility, environmental compliance costs, and capital-intensive generation investments. By contrast, distribution utilities operate with significantly lower business risk due to cost-of-service regulation and more predictable cash flows. An ROE for a distribution utility that exceeds the ROEs authorized for vertically integrated peers contradicts this fundamental risk distinction and suggests a flaw in the application or interpretation of Mr. Keller's modeling results.

Q DOES MR. KELLER'S ATTEMPT TO USE A DEREGULATED-ONLY PROXY GROUP JUSTIFY HIS HIGH ROE RECOMMENDATION?

A No. While Mr. Keller's effort to screen for deregulated utility companies may have been intended to better match the business risks faced by Wellsboro, the resulting 10.78% ROE cannot be reconciled with the actual decisions rendered by regulators nationwide for comparable electric distribution utilities. His recommended ROE of 10.78% is not only irregular in the context of recent ROE trends, but it also contradicts his own critique of inflated ROEs stemming from overreliance on CAPM and other market-based models. Indeed, despite claiming to rely primarily on the DCF model, Mr. Keller's recommended ROE reflects the upper end of estimates produced by models he himself characterizes as flawed or distorted in the current economic climate.

C. Mr. Keller's DCF Model is Based on Excessive Growth Rates

Q PLEASE SUMMARIZE MR. KELLER'S DCF MODEL.

A Mr. Keller performs a constant growth DCF analysis based on spot prices 52-week average as of May 14, 2025.[1] Mr. Keller assumes an average growth rate of 6.74% for his proxy group.[2] The indicated cost of equity for the spot stock price analysis is 10.77%, while the result for his 52-week stock price analysis is 10.79%. The midpoint of these two results is 10.78% and serve as the basis for his recommendation.[3]

Q PLEASE EXPLAIN THE SIMILARITIES BETWEEN YOUR CONSTANT GROWTH DCF ANALYSIS AND MR. KELLER'S CONSTANT GROWTH DCF ANALYSIS.

A Mr. Keller's proxy group growth rate (6.74%) is close to my proxy group's average growth rate of 6.87%. Our average constant growth DCF results are nearly identical.[4]

Q PLEASE SUMMARIZE YOUR PRIMARY CONCERN WITH MR. KELLER'S DCF ANALYSIS.

A My primary concern with Mr. Keller's DCF analysis is his assumed growth rate of 6.74% for his proxy group because it vastly exceeds the projected growth rate of the U.S. economy. As I discussed in my Direct Testimony, the consensus of research on the subject finds a utility's growth rate cannot exceed the growth rate of the economy

[1] I&E Exhibit No. 2, Schedule 7.
[2] *Id.*
[3] *Id.*
[4] The average constant growth DCF results presented in my Exhibit CCW-4 is 10.79%, or 1 basis point higher than Mr. Keller's average DCF result and ultimately his recommendation.

in which it provides services in perpetuity, which is the time period assumed by the DCF model. Given that Wellsboro provides distribution services in the United States, the projected long-term U.S. Gross Domestic Product ("GDP") growth rate is relevant.

Q WHAT IS THE PROJECTED LONG-TERM GROWTH RATE FOR THE U.S. ECONOMY?

A At the time of my analysis in my Direct Testimony, which is the same time of the analysis of Mr. Keller's Direct Testimony, the consensus for long-term GDP growth in the United States was 4.09%, which is 265 basis points lower than Mr. Keller's assumed average growth rate of 6.74% for his proxy group.

Q WHY IS THE GDP GROWTH PROJECTION A REASONABLE PROXY FOR THE MAXIMUM SUSTAINABLE LONG-TERM GROWTH RATE?

A The United State GDP growth projection is a reasonable upper limit, or proxy, for the maximum sustainable long-term growth rate in the DCF model because public utilities cannot indefinitely sustain a growth rate that exceeds the growth rate of the economy in which they sell services. A utilities' earnings and dividend growth are created by increased utility investment in its rate base. Examples of what can drive such investment are: service area economic growth, system reliability upgrades, or state and federal green energy initiatives. As such, the nominal U.S. GDP growth projection is a reasonable upper limit for utility sales growth, rate base growth, and earnings growth in the long-run.

Q DO YOU HAVE ANY FURTHER COMMENTS?

A Yes. Mr. Keller's use of a growth rate that is higher than the projected nominal U.S. GDP growth rate effectively says that Mr. Keller believes that utilities can indefinitely sustain a growth rate that exceeds the growth rate of the U.S. economy, in which the utility sells distribution services. However, Mr. Keller offers no explanation or data to show how a utility can indefinitely sustain a growth rate that exceeds the growth of the U.S. economy. Mr. Keller also fails to explain in his Direct Testimony what, if any, upper limit he would consider to be reasonable for his assumed growth rate for his proxy group. Given this flaw in his constant growth DCF analysis, it necessitates the consideration of a multi-stage DCF model to balance his result.

Q IS THE APPLICATION OF A MULTI-STAGE DCF MODEL USED IN PRACTICE?

A Yes. As I explained in my Direct Testimony, the multi-stage DCF model is widely used in practice. For example, the Chartered Financial Analyst ("CFA") Institute curriculum text states as follows:

> Multistage models are a staple valuation discipline of investment management firms using DCF valuation models.
>
> A survey of CFA Institute members with job responsibility for equity analysis indicates that, among respondents using a dividend discount model, two-stage and multistage models are used more often than the single-stage model (Stowe, Pinto, and Robinson 2018). Among analysts using a dividend discount model, 55% use a two-stage model, 11% use an H-model (a type of two-stage model), and 50% use a model with more than two stages (Stowe, Pinto, and Robinson 2018).[5]

[5]Chartered Financial Analyst Institute, 2023 CFA Program Level 2 Refresher Reading, Equity Valuation: Discounted Dividend Valuation, at page 30. [footnote omitted].

As Stowe *et al*. have revealed, the majority of equity analysts rely on multi-stage models more frequently than single-stage or constant growth models.

Q WHAT WOULD THE RESULTS OF A MULTI-STAGE DCF ANALYSIS BE BASED ON MR. KELLER'S INPUTS?

A Given Mr. Keller's proxy group growth rate (6.74%) is relatively close to my proxy group's average growth rate (6.87%), and our average constant growth DCF results are nearly identical,[6] the results of my multi-stage DCF analysis (8.62% and 8.39%) would be a close approximation.

Q HOW CAN THE MULTI-STAGE DCF ANALYSIS RESULT BE USED TO BALANCE THE RESULT OF MR. KELLER'S FLAWED DCF ANALYSIS?

A Assuming a multi-stage DCF result of 8.62%, the average of my multi-stage DCF analysis result and Mr. Keller's flawed constant growth DCF analysis results would be 9.7% [(10.78% + 8.62%) / 2]. This result is consistent with my recommended range 9.0% to 10.0%.

D. Mr. Keller's ROE Recommendation is Not Based on a Thorough Analysis

Q WHY IS MR. KELLER'S EXCLUSIVE RELIANCE ON A SINGLE CONSTANT-GROWTH DCF MODEL PROBLEMATIC?

A Although Mr. Keller claims to use the CAPM as a comparison of the results of his constant growth DCF analysis, Mr. Keller's exclusive reliance on the constant growth

[6]The average constant growth DCF results presented in my Exhibit CCW-4 is 10.79%, or 1 basis point higher than Mr. Keller's average DCF result and ultimately his recommendation.

DCF analysis is problematic because the cost of equity is not a directly observable figure; rather, it must be estimated using financial models that are based on assumptions and market expectations. No single model can be relied upon exclusively to estimate a fair and reasonable cost of equity because each model has its own strengths, limitations, and sensitivities to input assumptions. Mr. Keller's exclusive reliance on the constant growth DCF model is problematic because, other than being flawed, it ignores the insights that other well-established models, such as the sustainable growth DCF and multi-stage DCF analysis, or even the CAPM and the Risk Premium model, can provide.

By relying solely on a single model, Mr. Keller increases the risk of model-specific bias and fails to capture the full range of investor expectations. The constant growth DCF model, for instance, is highly sensitive to the assumed growth rate. As I discussed earlier in this testimony, Mr. Keller's analysis is flawed because it relies on growth rates that exceed the projected growth rate of the U.S. economy by a significant margin, which leads to inflated ROE estimates. Had Mr. Keller employed a multi-model approach, such as including a multi-stage DCF analysis, the CAPM and Risk Premium methods, all of which are widely used in regulatory proceedings, he could have cross-validated his constant growth DCF analysis results and mitigated the upward bias from his irregularly high growth assumptions.

Q WHY IS THE CONSIDERATION OF MULTIPLE MODELS IMPORTANT INFORMING AN UNBIASED OPINION?

A The consideration of multiple models is important in forming an unbiased opinion on a ROE recommendation because it is standard practice in the field of utility finance and

enhances the robustness and credibility of the resulting ROE recommendation. Ignoring these other models diminishes the reliability of Mr. Keller's recommendation and weakens the basis for his proposed ROE of 10.78%, which is well above national averages and recent Commission-authorized returns.

III. RESPONSE TO MR. FARR

Q HAVE YOU REVIEWED MR. FARR'S DIRECT TESTIMONY?

A Yes. Mr. Farr recommended several adjustments to Wellsboro's proposed revenue requirement. While he did not propose a specific total revenue requirement, Mr. Farr recommended a $386,239 reduction to Wellsboro's proposed $2.9 million increase. This reduction reflects his proposed use of a 10.00% proxy ROE, derived from the Pennsylvania Public Utility Commission's ("Commission") authorized ROE for Distribution System Improvement Charges ("DSIC"), even though he deferred a full ROE analysis to the OCA and I&E. Mr. Farr also opposed the Company's proposed 85-basis point size premium and 5-basis point performance adder, arguing that such upward adjustments are excessive and unsupported. He further recommended using the enacted 7.49% Pennsylvania corporate income tax rate for 2026 rather than the outdated 9.99% rate used by Wellsboro. Collectively, these adjustments would reduce the Company's requested rate increase from $2,899,388 to $2,513,149.

Q DO YOU AGREE WITH MR. FARR'S USE OF THE 10.00% DSIC ROE FROM THE COMMISSION'S QUARTERLY EARNINGS REPORT ("QER") AS A PROXY ROE IN THIS PROCEEDING?

A No, I do not agree with Mr. Farr's use of the 10.00% DSIC ROE from the Commission's QER as a proxy ROE for the Company. While Mr. Farr does not offer his own ROE recommendation, he assumes a 10.00% proxy ROE derived from the Commission's DSIC return published in its most recent QER. However, the Commission has expressly and repeatedly rejected the use of its DSIC ROE for purposes of establishing the cost of equity in base rate proceedings.

Q HAS THE COMMISSION ADDRESSED THIS ISSUE IN PRIOR CASES?

A Yes. In its May 8, 2025 Order in the Pike County Light & Power rate case (Docket Nos. R-2024-3052357 and R-2024-3052359), the Commission held that the DSIC ROE is "not relevant" to a base rate proceeding and distinguished it as an *industry-specific* figure determined quarterly, not a *company-specific* return derived from a fully developed evidentiary record. The Commission stated:

> We have previously found that the DSIC ROE is different from a ROE established in a base rate proceeding. We explained that the Commission determines the DSIC ROE on a quarterly basis and it is industry-specific, rather than a company-specific ROE set in a rate case.[7]

[7] *Pa. PUC v. Pike County Light & Power*, May 8, 2025 Order at page 28.

Q WHY IS MR. FARR'S RELIANCE ON THE DSIC ROE INAPPROPRIATE IN THIS CASE?

A Mr. Farr's opinion to use the DSIC ROE as a proxy ROE is unrelated to the Company's actual risks, financial structure, or cost of capital. He bypasses the entire cost of equity analysis process, including market-based models such as the DCF or CAPM, and relies instead on a figure that the Commission has determined is not suitable for use in base rate proceedings. As a result, the 10.00% proxy ROE Mr. Farr applies is arbitrary and flawed.

Q DOES MR. FARR PRESENT ANY INDEPENDENT ROE ANALYSES IN THIS PROCEEDING?

A No. Mr. Farr fails to present any independent ROE analyses in this proceeding. Instead, he explicitly defers to the analyses of the OCA and I&E, stating: "I do not have a recommendation for a specific ROE but rather defer to analysis and recommendations promulgated by the Office of Consumer Advocate ('OCA') and the Bureau of Investigation and Enforcement ('I&E')."[8]

As such, the OSBA has not independently developed a ROE recommendation and has not performed any market-based analyses to support its 10.00% proxy figure.

[8]OSBA St. No. 1 at page 10.

Q SHOULD MR. FARR'S DEFERRAL TO THE OCA'S OR I&E'S ROE ANALYSIS AND RECOMMENDED ROE BE GIVEN ANY WEIGHT?

A No. Mr. Farr's blind deferral to the OCA's or I&E's analyses and recommended ROE should be given no weight because he did not review or have knowledge about either my or I&E witness Keller's analyses and results prior to the submission of direct testimony. His blind deference to the OCA and I&E is arbitrary, containing no analysis or foundation.

Q SHOULD MR. FARR'S PROPOSED REVENUE REQUIREMENT REDUCTION BASED ON THE 10.00% ROE BE GIVEN ANY WEIGHT?

A No. Because Mr. Farr's proxy ROE is not grounded in a proper cost of equity analysis and is inconsistent with Commission precedent, the portion attributed to ROE of his proposed $386,239 downward adjustment to the Company's revenue requirement should be rejected.

IV. CONCLUSION

Q DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A Yes, it does.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No. R-2025-3054394
	:	R-2025-3054393
Citizens' Electric Company of Lewisburg, PA, Valley Energy, Inc., and Wellsboro Electric Company	:	R-2025-3054392

VERIFICATION

I, Christopher C. Walters, hereby state that the facts above set forth in my Rebuttal Testimony, OCA Statement No. 2R, are true and correct to the best of my knowledge, information, and belief and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa.C.S. § 4904 (relating to unsworn falsification to authorities).

DATED: August 13, 2025

Signature: */s/ Christopher C. Walters*
Christopher C. Walters

Address: Brubaker & Associates, Inc.
16690 Swingley Ridge Road
Suite 140
Chesterfield, MO 63017

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	Docket No.: R-2025-3054394
v.	:	
	:	
Citizens' Electric Company of Lewisburg	:	

REBUTTAL TESTIMONY

OF

Michael Deupree

On behalf of the

PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

OCA Statement 3R

Date Served: August 13, 2025

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS?

A. My name is Michael W. Deupree. My business address is 5800 One Perkins Place Drive, Suite 5-F, Baton Rouge, Louisiana, 70808.

Q. HAVE YOU PREVIOUSLY FILED TESTIMONY IN THIS PROCEEDING?

A. Yes. I filed direct testimony in this proceeding on July 15, 2025, on behalf of the Pennsylvania Office of Consumer Advocate ("OCA").

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to respond to elements of the direct testimony of Ethan H. Cline on behalf of the Bureau of Investigation and Enforcement ("I&E"). Specifically, I will respond to I&E's presentation of Citizens' Electric Company of Lewisburg ("Citizens" or the "Company") customer cost analysis.

II. CUSTOMER COST ANALYSIS

Q. DID I&E PREPARE A CUSTOMER COST ANALYSIS FOR SOME COMPANY RATE CLASSES?

A. Yes. I&E in its Direct Testimony presents the results of a customer cost analysis that shows that the Company's proposed customer charge for residential service ("RS"), commercial space heating ("SH"), general light and power-1 ("GLP-1"), and general light and power-3 ("GLP-3") rate classes are less than cost per customer to provide customer-related activities such as meter reading, customer billing and accounting, and customer service and information expenses.[1]

[1] Direct Testimony of Ethan H. Cline at 8.

Q. DID YOU INCLUDE AN ANALYSIS OF CUSTOMER-RELATED COSTS IN YOUR DIRECT TESTIMONY?

A. Yes. Contrary to I&E's findings, I find that each of the four rate classes listed are currently fully recovering customer-related costs through the existing customer charge, and that, therefore, the Company's proposed increase in customer charges is not necessary.[2]

Q. CAN YOU RECONCILE I&E'S CUSTOMER COST ANALYSIS RESULTS TO YOUR OWN?

A. Yes. I&E's customer cost analysis results come directly from the Company's allocated cost of service ("ACOS") analysis.[3] However, this analysis assumes the Company's requested rate of return on rate base ("ROR") of 8.49 percent in calculating the required return on customer-related rate base such as services, meters, and line transformers.[4] The Company's requested ROR is dependent on the Commission's finding of a just and reasonable ROR at the end of this proceeding and therefore is unknown at the current juncture. Therefore, for my analysis of customer-related costs, I used the Company's estimated ROR under current rates of 1.46 percent for the fully-projected future test year ("FPFTY").

Q. DO YOU BELIEVE THAT IT IS CORRECT FOR THE COMMISSION TO RELY ON THE COMPANY'S ROR UNDER CURRENT RATES FOR AN ANALYSIS OF CUSTOMER-RELATED COSTS?

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[2] Direct Testimony of Michael W. Deupree at 31, Table 11.

[3] *See*, Direct Testimony of Howard S. Gorman at Exhibit HSG-1, Schedule E-1C.

[4] *Id.*

A. Yes. The Company's forecasted ROR of 1.46 percent during the FPFTY assumes no change in rates, and, therefore, is not subject to the Commission's decision of just and reasonable rates in the current proceeding.

Q. HAVE YOU PREPARED AN ALTERNATIVE CUSTOMER COST ANALYSIS USING AN ROR OTHER THAN THE COMPANY'S ACHIEVED ROR OF 1.46 PERCENT?

A. Yes. Table 1 below presents the results of an alternative customer cost analysis assuming a ROR of 7.44 percent, consistent with OCA Witness Walters' proposed return on equity of 9.50 percent.[5]

Table 1: Analysis of Company Customer-Related Costs at OCA's Proposed ROR

Line No.	Description	Residential Service (RS)	Commercial and Industrial Service: Space Heating (SH)	General L&P (GLP-1)	General L&P (GLP-3)
1	Customer-Related Costs per Company's ACOS				
2	Class Functionalized Customer Billing Expenses	$ 1,248,583	$ 978	$ 278,990	$ 58,613
3	Number of Bills	72,612	36	13,644	504
4	**Monthly Customer-Related Costs/Customer**	**$ 17.20**	**$ 27.15**	**$ 20.45**	**$ 116.30**
5	Customer Charge Revenue at Current Rates				
6	Customer Charge Revenue at Current Rates	$ 951,217	$ 727	$ 218,304	$ 27,720
7	Number of Bills	72,612	36	13,644	504
8	**Monthly Customer Charge Revenue/Customer**	**$ 13.10**	**$ 20.19**	**$ 16.00**	**$ 55.00**
9	**Relationship of Customer Charge Revenues to Customer-Related Costs**	**76.18%**	**74.37%**	**78.25%**	**47.29%**

Source: Company's Response to OCA-I-1, Attachment A (Schedule E)

[5] Direct Testimony of Christopher C. Walters at 3:3-7.

Q. USING THE OCA's PROPOSED PRE-TAX ROR OF 7.44 PERCENT, WHAT DOES YOUR ALTERNATIVE CUSTOMER COST ANALYSIS FIND?

A. This alternative analysis finds that RS customers currently recover more than 76 percent of customer-related costs through the existing customer charge. Likewise, SH and GLP-1 customers currently recover more than 74 and 78 percent, respectively, of customer-related costs through the existing customer charge. Only the GLP-3 class' current customer charge fails to recover a significant portion of customer-related costs, recovering approximately 47 percent of customer-related costs.

Q. DO THESE RESULTS INDICATE ANY PRESSING NEED TO INCREASE MONTHLY CUSTOMER CHARGE RATES?

A. No. Even under this alternative analysis of customer-related costs, the RS and most of Citizens' commercial service rate classes currently cover the substantial portion of their customer-related costs through the existing monthly customer charge. The only potential exception to this finding is the GLP-3 rate class, which covers larger commercial customers with monthly billing demand in excess of 50 kW.[6]

III. CONCLUSIONS AND RECOMMENDATIONS

Q. HAVE YOUR RECOMMENDATIONS PRESENTED IN YOUR DIRECT TESTIMONY CHANGED AFTER REVIEWING INTERVENING PARTIES DIRECT TESTIMONIES?

[6] Notably, the level of customer charges for large commercial customers is not as meaningful as it is for residential and small commercial customers as large commercial customers pay a greater percentage of monthly bill through relatively fixed monthly demand charges.

A. No. I continue to recommend the Commission reject Citizens' proposed increases in customer charges because they disproportionately impact low-income customers and reduce customer incentives to reduce usage, contrary to public goals of promoting energy efficiency. Furthermore, Citizens' existing residential and small commercial customer charges are already higher than the regional average of peer investor-owned utilities, and the proposed increase would make the charges the among the highest of its peers. Finally, a correct analysis of customer-related costs from Citizens' ACOS finds that all residential and commercial rate classes are currently recovering *all* customer-related costs through monthly customer charges, and even an alternative analysis of customer-related costs from Citizens' ACOS finds that the RS and most commercial rate classes are currently recovering a very substantial portion of customer-related costs through monthly customer charges.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No. R-2025-3054394
	:	
Citizens' Electric Co. of Lewisburg, PA	:	

VERIFICATION

I, Michael W. Deupree, hereby state that the facts above set forth in my Rebuttal Testimony, OCA Statement No. 3R, are true and correct to the best of my knowledge, information, and belief and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa.C.S. § 4904 (relating to unsworn falsification to authorities).

DATED: August 13, 2025

Signature: /s/ Michael W. Deupree
Michael W. Deupree

Address: Acadian Consulting Group
5800 One Perkins Place Drive
Suite 5-F
Baton Rouge, LA 70808

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	Docket No.: R-2025-3054392
v.	:	
	:	
Wellsboro Electric Company	:	

REBUTTAL TESTIMONY

OF

Michael Deupree

On behalf of the

PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

OCA Statement 3R

Date Served: August 13, 2025

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS?

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A. Yes. I filed direct testimony in this proceeding on July 15, 2025, on behalf of the Pennsylvania Office of Consumer Advocate ("OCA").

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to respond to elements of the direct testimony of Ethan H. Cline on behalf of the Bureau of Investigation and Enforcement ("I&E"). Specifically, I will respond to I&E's presentation of Wellsboro Electric Company ("Wellsboro" or the "Company") customer cost analysis.

II. CUSTOMER COST ANALYSIS

Q. DID I&E PREPARE A CUSTOMER COST ANALYSIS FOR SOME COMPANY RATE CLASSES?

A. Yes. I&E in its Direct Testimony presents the results of a customer cost analysis that shows that the Company's proposed customer charge for residential service ("RS") and residential service-all electric ("RSAE"), non-residential service ("NRS") and non-residential service-heating ("NRH") rate classes are less than cost per customer to provide customer-related activities such as meter reading, customer billing and accounting, and customer service and information expenses.[1]

[1] Direct Testimony of Ethan H. Cline at 9.

Q. DID YOU INCLUDE AN ANALYSIS OF CUSTOMER-RELATED COSTS IN YOUR DIRECT TESTIMONY?

A. Yes. Simlar to I&E's findings, I find that commercial service ("CS"), commercial service-heating ("CSH"), and industrial service ("IS") customers are currently fully recovering customer-related costs through the existing customer charge.[2] However, I find that RS, RSAE, NRS, and NRH customers are currently recovering a substantial portion of customer-related costs through the existing customer charge.[3] I therefore find that the Company's proposed increase in customer charges is not necessary.[4]

Q. CAN YOU RECONCILE I&E'S CUSTOMER COST ANALYSIS RESULTS TO YOUR OWN?

A. Yes. I&E's customer cost analysis results come directly from the Company's allocated cost of service ("ACOS") analysis.[5] However, this analysis assumes the Company's requested rate of return on rate base ("ROR") of 8.18 percent in calculating the required return on customer-related rate base such as services, meters, and line transformers.[6] The Company's requested ROR is dependent on the Commission's finding of a just and reasonable ROR at the end of this proceeding and therefore is unknown at the current juncture. Therefore, for my analysis of customer-related costs, I used the Company's estimated ROR under current rates of 1.46 percent for the fully-projected future test year ("FPFTY").

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[2] Direct Testimony of Michael W. Deupree at 31, Table 11.

[3] *Id.*

[4] *Id.* at 32:16-19.

[5] *See*, Direct Testimony of Howard S. Gorman at Exhibit HSG-1, Schedule E-1C.

[6] *Id.*

Q. DO YOU BELIEVE THAT IT IS CORRECT FOR THE COMMISSION TO RELY ON THE COMPANY'S ROR DURING UNDER CURRENT RATES FOR AN ANALYSIS OF CUSTOMER-RELATED COSTS?

A. Yes. The Company's forecasted ROR of 0.68 percent during FPFTY assumes no change in rates, and, therefore, is not subject to the Commission's decision of just and reasonable rates in the current proceeding.

Q. HAVE YOU PREPARED AN ALTERNATIVE CUSTOMER COST ANALYSIS USING AN ROR OTHER THAN THE COMPANY'S ACHIEVED ROR OF 0.68 PERCENT?

A. Yes. Table 1 below presents the results of an alternative customer cost analysis assuming a ROR of 7.13 percent, consistent with OCA Witness Walters' proposed return on equity of 9.50 percent.[7]

Table 1: Analysis of Company Customer-Related Costs at OCA's Proposed ROR

Line No.	Description	Residential Service		Commercial and Industrial Service				
		Residential (RS)	All Electric (RSAE)	Non-Residential (NRS)	Non-Res. Heating (NRH)	Commercial (CS)	Comm. Heating (CSH)	Industrial (IS)
1	Customer-Related Costs per Company's ACOS							
2	Class Functionalized Customer Billing Expenses	$1,075,688	$ 6,081	$ 195,616	$ 208	$ 121,425	$ 310	$ 11,241
3	Number of Bills	61,910	350	11,258	12	4,704	12	160
4	**Monthly Customer-Related Costs/Customer**	**$ 17.38**	**$ 17.37**	**$ 17.38**	**$ 17.37**	**$ 25.81**	**$ 25.81**	**$ 70.25**
5	Customer Charge Revenue at Current Rates							
6	Customer Charge Revenue at Current Rates	$ 741,480	$ 4,200	$ 136,106	$ 147	$ 149,132	$ 550	$ 13,600
7	Number of Bills	61,910	350	11,258	12	4,704	12	160
8	**Monthly Customer Charge Revenue/Customer**	**$ 11.98**	**$ 12.00**	**$ 12.09**	**$ 12.25**	**$ 31.70**	**$ 45.83**	**$ 85.00**
9	**Relationship of Customer Charge Revenues to Customer-Related Costs**	**68.93%**	**69.07%**	**69.58%**	**70.50%**	**122.82%**	**177.55%**	**120.99%**

Source: Company's Response to OCA-I-1, Attachment A (Schedule E)

Q. USING THE OCA's PROPOSED PRE-TAX ROR OF 7.13 PERCENT, WHAT DOES YOUR ALTERNATIVE CUSTOMER COST ANALYSIS FIND?

[7] Direct Testimony of Christopher C. Walters at 3:2-4.

A. This alternate analysis finds that RS and RSAE customers currently recover approximately 69 percent of customer-related costs through the existing customer charge. Likewise, NRS and NRH customers currently recover approximately 70 percent of customer-related costs through the existing customer charge. Larger commercial and industrial customers are currently recovering more than current customer-related costs through the existing customer charge.

Q. DO THESE RESULTS INDICATE ANY PRESSING NEED TO INCREASE MONTHLY CUSTOMER CHARGE RATES?

A. No. Even under this alternative analysis of customer-related costs, all Company residential and commercial service rate classes cover the majority of their customer-related costs through monthly customer charges. The lowest, the RS class, recovers nearly 69 percent of its customer-related costs through its monthly customer charge.

III. CONCLUSIONS AND RECOMMENDATIONS

Q. HAVE YOUR RECOMMENDATIONS PRESENTED IN YOUR DIRECT TESTIMONY CHANGED AFTER REVIEWING INTERVENING PARTIES DIRECT TESTIMONIES?

A. No. I continue to recommend the Commission reject Wellsboro's proposed increases in customer charges because they disproportionately impact low-income customers and reduce customer incentives to reduce usage, contrary to public goals of promoting energy efficiency. Furthermore, Wellsboro's existing residential customer charge is the third highest in the region and the proposed increase would make the charge the highest among regional peer investor-owned utilities. Finally, a correct analysis of customer-related costs from Wellsboro's ACOS finds that all residential and commercial

rate classes are currently recovering *nearly all* customer-related costs through monthly customer charges.

Q. DO YOU CONTINUE TO SUPPORT YOUR ALTERNATIVE RECOMMENDATION IF THE COMMISSION DECIDES AN INCREASE IN MONTHLY CUSTOMER CHARGES IS WARRANTED?

A. Yes. I continue to recommend the Commission limit its increase in Wellsboro monthly customer charges to only that required to bring the Company's customer charges in line with Citizens' Electric Company, if the Commission decides an increase in monthly customer charges is warranted. This would limit the increase in residential customer charge to $13.10 per month.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No. R-2025-3054392
	:	
Wellsboro Electric Company	:	

VERIFICATION

I, Michael W. Deupree, hereby state that the facts above set forth in my Rebuttal Testimony, OCA Statement No. 3R, are true and correct to the best of my knowledge, information, and belief and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa.C.S. § 4904 (relating to unsworn falsification to authorities).

DATED: August 13, 2025

Signature: /s/ Michael W. Deupree
Michael W. Deupree

Address: Acadian Consulting Group
5800 One Perkins Place Drive
Suite 5-F
Baton Rouge, LA 70808

OCA STATEMENT 5R

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	**)**	
v.	**)**	
Citizens' Electric Company of Lewisburg, PA	**)**	**Docket No. R-2025-3054394**
	)	
	)	

REBUTTAL TESTIMONY

OF

ZACH TETI

ON BEHALF OF THE

PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

August 13, 2025

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OCA Exhibit ZT-1 – Curriculum Vitae of Zach Teti

OCA Exhibit ZT-2 – Company Response to Interrogatory SP-II-5

OCA Exhibit ZT-3 – Billing Demand Proposal Summary Table

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND BUSINESS DESCRIPTION.

A. My name is Zach Teti. I am a Senior Regulatory Analyst at the Pennsylvania Office of Consumer Advocate ("OCA"). My office is located at 555 Walnut St, Harrisburg, PA 17101. The OCA is a state agency that represents the interests of Pennsylvania utility consumers before the Pennsylvania Public Utility Commission ("PUC"), federal regulatory agencies, and state and federal courts. The OCA was created by the Pennsylvania General Assembly in 1976 and is an independent office within the Office of Attorney General.

Q. PLEASE STATE YOUR EDUCATIONAL BACKGROUND.

A. I received a B.A. degree in Economics from Millersville University (Millersville, PA) in 2013 and an M.S. in Energy Economics from Pennsylvania State University (University Park, PA) in 2021.

Q. WHAT IS YOUR PROFESSIONAL BACKGROUND?

A. I have twelve years of experience in the banking and energy industries, most recently specializing in organized wholesale and retail electricity markets. My background comprises energy market design and analysis; econometric research in an academic setting; and financial planning, analysis, and control in a banking setting. I was employed as a Senior Regulatory Analyst serving as a representative of the NEPOOL Markets Committee between 2021 and 2024, analyzing wholesale market design and its impact on default service procurement of electricity. In this position, I also wrote energy policy recommendations and helped with implementation of rulemaking ordered by the Federal Energy Regulatory Commission ("FERC"), such as FERC Order 2222 which aimed to better enable distributed energy resources (DERs) to

participate in the electricity markets run by regional grid operators.[1] I joined the OCA as a Senior Regulatory Analyst in April 2025.

Q. ON WHOSE BEHALF ARE YOU OFFERING THIS TESTIMONY?

A. I am offering this testimony on behalf of the OCA. My testimony is intended to address issues from the standpoint of residential customers of electricity. My comments also impact sizable customer-generators; that is, customers with distributed generation resources with output capacity that exceeds 400 kilowatts ("kW"), are interconnected to the electric distribution system, and participate in net metering.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY IN THIS PROCEEDING?

A. I am responding to the Direct Testimony of Brett Nolt, Solar Projects' Statement No. 1, submitted on behalf of Kelly Road Solar, LLC, Lancaster Avenue Solar, LLC, and Twilight Renewables, LLC (collectively, the "Solar Projects"). My rebuttal testimony addresses certain elements of the proposed Billing Demand methodology of Citizens' Electric Company of Lewisburg, PA ("Citizens" or "Company") submitted to take effect in late 2025 or early 2026. The Company and Solar Projects have provided comments on specific issues that I will address including: (1) the importance of efficient procurement of the Company's default service passed through Generation Supply Service Rate-1 ("GSSR-1"); (2) the concern of a risk premium noted in a recent PUC Opinion and Order; and (3) the fairness of the rate of compensation for energy produced by customer-generators.

Q. HOW IS THE REMAINDER OF YOUR REBUTTAL TESTIMONY ORGANIZED?

[1] https://www.ferc.gov/ferc-order-no-2222-explainer-facilitating-participation-electricity-markets-distributed-energy

A. Section I is an introduction. Section II presents a summary of the Company's proposed Billing Demand methodology. Section III presents a summary of the Solar Projects' witness Nolt's Direct Testimony. Section IV, the final section of my Rebuttal Testimony, presents my discussion of the Company's proposal, responds to Mr. Nolt, and provides my recommendations concerning the Company's proposed Billing Demand methodology.

Q. DO YOU HAVE ANY APPENDICES OR EXHIBITS TO YOUR TESTIMONY?

A. Yes. Attached to my testimony as Appendix A is my CV. Also attached are Exhibit ZT-2 (Company's response to Interrogatory SP-II-5) and Exhibit ZT-3 (Billing Demand Proposal Summary Table).

Q. ARE YOU RECOMMENDING THAT THE COMPANY'S PROPOSED BILLING DEMAND METHODOLOGY BE APPROVED BY THE PUC?

A. Yes, I am. The overall default service supply portfolio and the specific default service procured on behalf of residential customers would benefit from the Company's proposed Billing Demand methodology.

Q. WHY ARE YOU RECOMMENDING THAT THE COMPANY'S PROPOSED BILLING DEMAND METHODOLOGY BE APPROVED?

A. In my review of (1) the Company's response to SP-II-5 (which is attached to my testimony as Exhibit ZT-2), and (2) the Direct Testimony of Brett Nolt on behalf of the Solar Projects, I found two themes to be most salient. First, the top priority in this matter should be to strive for fairness across customers and customer classes. In the Company's response to SP-II-5, the Company outlines the effect of a streamlined approach to default service procurement (albeit a somewhat abstract outline) arising from this proposed Billing Demand methodology. The analysis illustrates a fair

outcome for customers which will be explained in the next section. Second, Solar Projects may be overstating the impact of the proposed Billing Demand methodology on customer-generator compensation. The proposed Billing Demand methodology accomplishes fairness by improving the procurement process for default service and simultaneously compensating customer-generators at a "full retail value for all energy produced" that does not corrupt the efficiency of the procurement process.[2] For these reasons, I am recommending that the Company's proposed Billing Demand methodology be approved by the PUC.

Q. ARE YOU MAKING ANY ADDITIONAL RECOMMENDATIONS?

A. Yes. As just stated, Solar Projects may be overstating the impact of the proposed Billing Demand methodology on compensation for energy produced by customer-generators. In this regulatory proceeding and prior to any accepted tariff change, clarity should be reached on this subject. This topic provokes the complicated value proposition between (1) load reduction and its effect on PJM costs (and which customer class should be the recipient of these reduced costs while paying local customer-generators at a full retail rate), (2) compensating local customers-generators at a retail rate that consists of individual or multiple wholesale market components (even though they are not contributing to resource adequacy or reducing transmission cost allocation), or (3) direct wholesale market participation and effectively stripping customer-generators out of the retail market and procurement scope.

II. SUMMARY OF THE COMPANY'S BILLING DEMAND PROPOSAL

Q. HOW DOES THE COMPANY PROPOSE TO DEFINE BILLING DEMAND IN THIS PROCEEDING?

[2] Citizens' Tariff, Rider B – Net Metering p. 66

A. The Company proposes to add a new definition of "Billing Demand" in the Definitions section of the Tariff as follows: "Billing Demand shall reflect the Customer's use of the distribution system, which will be the greater of Gross Generator Rating (kW(AC)) as stated in the generator interconnection application or the maximum demand of the customer during any 15-minute period during the current month."[3]

Q. PLEASE DESCRIBE THE COMPANY'S PROPOSAL REGARDING BILLING DEMAND.

A. The Company further proposes a change to Paragraph 26(a) of the Tariff re: "Determination of Billing Demand," as follows: "Billing Demand shall reflect the Customer's maximum use of the distribution system during the 15-minute period of maximum use for the month. This shall be the maximum energy supplied by the Company to the Customer's meter during the applicable period or, for customer-generators that qualify for Rider B – Net Metering, the greater of the maximum energy supplied by the Company to the meter or the nameplate generator capacity indicated on the application to interconnect."[4]

Q. DID THE COMPANY ADDRESS ITS TARIFF CHANGES IN TESTIMONY?

A. Yes. In Citizens Statement No. 4, Direct Testimony of Company President Nathan Johnson, at pages 17-18,[5] Mr. Johnson explained that in the recent *UGI Electric* decision at Docket No. P-2004-3049343[6] the PUC indicated that customer-generators can be classified for generation purposes according to their peak electricity imported from the electric distribution company ("EDC") or exported to the EDC. Based on this decision, the

[3] Citizens' Rate Case Filing, p. 23

[4] *Id.*, p. 29

[5] Direct Testimony and Exhibits of Nathan Johnson, pp. 17-18

[6] *Petition of UGI Utilities, Inc-Electric Division for Approval of a Default Service Plan for the Period of June 1, 2025 though May 31, 2029*¸ Docket No. P-2004-3049343, et al (*UGI Electric*).

Company proposes to clarify in its tariff that customer-generator's net power flow from or onto the Company's distribution system will be used to establish the distribution charges for the account and eligibility for the Generation Supply Service Rate ("GSSR")-1 or GSSR-2. For customers with Billing Demands over 400 kW, the annual cash out will be a weighted average locational marginal price ("LMP").[7]

Q. ACCORDING TO MR. JOHNSON, WHY IS THE PROPOSAL APPROPRIATE?

A. Mr. Johnson explained that it is appropriate to use the net power flow from or onto the Company's distribution system because using these measures provides an accurate reflection of the Customer's use of the distribution system. From a distribution perspective, Mr. Johnson testified that the EDC must plan the same for a customer that is exporting 400 kW to Citizens' as it does for a customer that is receiving 400 kW from Citizens'. Mr. Johnson testified that the Company's planning for a customer's export of power to Citizens' system is more complicated because of potential variability, voltage sags/surges and other issues. Mr. Johnson testified that it is equitable to charge a customer exporting 400 kW to [the Company]] similar to how [they] charge a customer that uses or imports 400 kW. Mr. Johnson noted that in the recent *UGI Electric* Order, the Commission determined that [it] is appropriate to treat these customers similarly for generation supply services. For Citizens', this will ensure that [they] apply a uniform definition of "billing demand", which is used in [their] distribution rate schedules and the GSSR-1 and GSSR-2 Riders.[8]

[7] Direct Testimony and Exhibits of Nathan Johnson, pp. 17-18
[8] *Id.*

III. SUMMARY OF THE SOLAR PARTIES' RESPONSE

Q. PLEASE SUMMARIZE MR. NOLT'S DIRECT TESTIMONY.

A. Mr. Nolt opposes the Company's proposal to add a new definition of Billing Demand to the tariff for two reasons. First, he testified that the tariff change will institute a new demand charge in GLP-1 Rate Class for power being sent to the EDC system by customer-generators that will be approximately 126% higher than the current tariff (varying on a case-by-case basis) with no demonstration of increased costs by Citizens. Next, he testified that the tariff change will impact the default service procurement class in which the Solar Projects are classified and thus change the rate of their compensation. Under the current tariff, the Solar Projects are in GSSR-1 because demand for the five of the six projects of the Solar Projects is essentially zero as they are measured purely on the basis of what these customers receive from Citizens and not by the power they export. With the Company's proposed Billing Demand methodology, the above 400kW threshold would move the Solar Projects to GSSR-2, which Mr. Nolt argues is akin to a wholesale rate. He testified that Solar Projects would suffer irreparable harm as a result because the compensation method for net metering will change.[9]

IV. DISCUSSION AND RECCOMMENDATIONS

Q. DID YOU PREPARE A TABLE THAT OUTLINES THE IMPACT OF THE COMPANY'S BILLING DEMAND PROPOSAL ON RATE SCHEDULES AND SUPPLY RATES.

A. Yes. Please see Exhibit ZT-3.

[9] Direct Testimony of Brett Nolt, pp 3-9.

Q. PLEASE COMMENT ON THIS TABLE SHOWN IN EXHIBIT ZT-3.

A. GSSR-1 and GSSR-2 are applied to customers that take default service. For all RS customers, the generation charge is GSSR-1. RS customers pay at a GSSR-1 rate if they are net buyers and receive GSSR-1 if they are net sellers. For GLP-1 and GLP-3 customers, the service rate is determined by Billing Demand. Customers with monthly Billing Demands under 400 kW for each of the prior 12 months will be applied to the GSSR-1. Customers with a monthly Billing Demand of 400 kW or more during any month in the last 12 months will be applied to the GSSR-2. GSSR-1 is procurement-based. GSSR-1 is based on "Purchased Power Costs for the compliance period incurred by the Company to acquire generation supply."[10] GSSR-2 is market-based with multiple components. An example of a component is:

> *"GSSR-2 Energy Charge per kWh: The product of the actual real-time PJM West Hub Locational Marginal Prices ("LMPs") for each hour of the billing month expressed in cents per kWh (including the Distribution Loss Adjustment), times the customer's actual energy use during each hour of the billing month."*[11]

While the table illustrates that GSSR-1 can be applied to both RS and GLP-1 service schedules, the proposed delineation of service rate by Billing Demand for GLP-1 customers is created to procure an efficient quantity of supply for the bulk of customers via DSP suppliers in GSSR-1. This approach ringfences similarly situated customers apart from large customers and virtually commercial customers with generation that exceeds 400 kW.

Q. WHICH INTEROGATORY BETWEEN THE SOLAR PARTIES AND THE COMPANY BEST ADDRESSES THE IMPACT OF THE BILLING DEMAND PROPOSAL?

[10] Citizens' Rate Case Filing, p. 33
[11] Citizens' Rate Case Filing, p. 34

A. Interrogatory SP-II-5 and the Company's response thereto best addresses the impact of the Billing Demand proposal. It is attached to my testimony as Exhibit ZT-2. The interrogatory asks: "Please reference Citizens' St. No. 4, p. 17. Has Citizens conducted any studies or analyses of the effects of this tariff change on Citizens' default procurement of electricity based on its Default Service Plan ("DSP")? If yes, please provide all studies or analyses related to the same."

Q. PLEASE BRIEFLY DESCRIBE THE ANALYSIS DONE BY THE COMPANY.

A. In SP-II-5 Attachment A, the Company utilizes a numerical example to compare two scenarios. The first scenario entitled "Energy Purchase through Wholesale Supplier" reflects the proposed Billing Demand methodology which would effectively separate residential customers from sizable customer-generators. The second scenario entitled "Energy Purchase through Net Metered Export" reflects the status quo incorporation of sizable customer-generators in default service procurement under the GSSR-1. The comparison of these two scenarios illustrates that these customer-generators cannot be used to satisfy capacity requirements (due to findings in SP-II-5 Attachment B) and that PJM costs will be incurred in both scenarios (with and without generation from customer-generators).[12] In the first scenario, customers in essence "get what they paid for" which is cost-effective; that is, residential customers pay for the energy, capacity, and transmission that serves them. Paying only for what serves them is cost-effective. If expected output from local customer-generators could be taken into account to meet

[12] Citizens' Response to SP-II-5 at p. 2: "For nearly half of the past decade's PJM Capacity and Transmission Peak hours, SPV output from either model was 20% or less of rated capacity, demonstrating the limited ability of net-metered SPV to mitigate PJM costs."

capacity obligations, then there could be a reduction in PJM costs due to this accredited value, but that is not how it currently works as outlined by the Company.[13]

A. Importance of Efficient Procurement of the Default Service Served on the GSSR-1

Q. PLEASE EXPLAIN THE IMPORTANCE OF EFFICIENT PROCUREMENT OF DEFAULT SERVICE PASSED THROUGH GSSR-1.

A. Utilities must meet their statutory responsibilities by procuring a default service portfolio that is designed to ensure service at the least cost over time.[14] To achieve this, utilities ensure reliable electricity supply by engaging in prudently procured load supply contracts in a streamlined manner, which requires a clear understanding of forecasted load for a somewhat nuanced base of customers. That is, getting the quantity correct is key for the efficient procurement of default service supply that will be passed through to customers at GSSR-1. Implementation of the proposed Billing Demand methodology should reduce the uncertainty of output from large customer-generators (output capacity > 400 kW), helping with the efficiency of this procurement. By shifting large customer-generators into the existing rate of GSSR-2, the task of efficient default service procurement for the bulk of customers becomes more achievable. Again, I agree with the Citizens model provided in response to SP-II-5. The model reflects the difference between efficient and inefficient procurement of the company's DSP for residential customers.

[13] Citizens response to this topic on August 4, 2025: "The Company does not believe it is appropriate to incorporate any capacity or transmission impact into its analysis, however, because net-metered generation does not guarantee those savings and is economically disincentivized to export during peak demand periods. Please note that a customer generator on the GSSR-2 rate would see the benefit of a zero transmission and/or capacity obligation if it successfully offsets its on-site consumption during the relevant PJM peaks." In other words, this benefit appears to be capped at zero and seemingly cannot be negative (i.e., compensated as if contributing to resource adequacy or reducing transmission cost allocation). The OCA will send interrogatories to further clarify.

[14] 52 Pa. Code § 54.185. Default service programs and periods of service.

Q. PLEASE SUMMARIZE.

A. DSP suppliers will serve load and incur similar PJM costs with or without generation from local customer-generators. In default service procurement, it is important to procure the correct quantity of electricity to avoid incurring excessive costs.[15] Again, I agree with the Citizens model provided in response to SP-II-5, which reflects the effect of a straightforward load forecast used in procurement from wholesale suppliers passed through at GSSR-1. Excessive costs are mitigated by the Company's proposed Billing Demand methodology.

B. Extension of the Risk Premium Concern in PUC's *UGI Electric* Opinion and Order

Q. PLEASE PROVIDE THE RELEVANT PORITONS OF THE PUC'S RECENT *UGI ELECTRIC* DECISION (P-2024-3049343) RELATED TO RISK PREMIUMS DRIVEN BY CUSTOMER-GENERATOR UNCERTAINTY.

A. From the PUC's Opinion and Order:

> The Company determined that if large customer-generators were to be included in the GSR-1 group, then: (1) their output would decrease GSR-1 group load and tranche size; (2) there is substantial question as to the level of output and timing of when these projects will become operational; and (3) these large customer-generators have the ability to leave default service at any time and participate in the wholesale market, thereby creating an attrition risk if projects opt to leave GSR-1 service and shop their output elsewhere. **UGI argued that each of these factors would substantially increase risk for wholesale suppliers, causing higher bid premiums and likely reducing the number of competitive bidders.**[16]

[15] Refer to PJM Manual 18 7.5 Daily Unforced Capacity Obligations for these roles and responsibilities,
[16] PA PUC Opinion and Order, p. 23 (emphasis added).

Q. DOES CITIZENS OFFER ANY SIMILAR REMARKS?

A. Yes. From Citizens' Response to SP-II-5, "…net-metered customer-generators directly benefit from the price inflation that they cause in a compounding fashion that increases as more net-metered generation is installed."[17]

Q. DO YOU SHARE THIS CONCERN?

A. Yes, I do share this concern.

Q. IS THE EFFECT OF THIS RISK PREMIUM INCORPORATED IN CITIZENS' ANALYSIS OFFERED IN RESPONSE TO SP-II-5?

A. No. While the Company did not show this effect in their analysis, the Company and I share the concern about the risk premiums associated with customer-generator uncertainty described in the above excerpt of the PUC's Opinion and Order. In the above remark, the Company expresses a comparable concern: that a large customer-generator stands to benefit from "price inflation that they cause in a compounding fashion." I take this statement to mean that the large customer-generator (output capacity > 400 kW) stands to benefit from higher prices caused by the risk premiums added to DSP suppliers to address their risks caused by unknown output quantities and attrition risk of large customer-generators.

Q. WILL THE PROPOSED BILLING DEMAND METHODOLOGY MITIGATE THE NEED FOR THIS RISK PREMIUM?

A. Yes. The proposed Billing Demand methodology should reduce over time the need for suppliers to include this risk premium in their offers when participating in default service procurement auctions to be passed through GSSR-1.

[17] Citizens' Response to SP-II-5, p. 2

C. Solar Projects' Concern About the Rate for Compensation of Customer-Generators

Q. WHY ARE THE SOLAR PROJECTS CONCERNED WITH THE PROPOSED BILLING DEMAND PROPOSAL?

A. In the proposed Billing Demand methodology, net metering compensation for large customer-generators (output capacity > 400 kW) at a more advantageous rate will be discontinued.

Q. WHICH QUESTION RAISED BY MR. NOLT ADDRESSES THE IMPACT OF THE BILLING DEMAND PROPOSAL AS TO COMPENSATION?

A. "What are the effects on net metered solar projects over 400kW that primarily provide power for offsite usage (either virtual net metering from a customer site to a different site operated by that same customer due to siting constraints, or simply selling power to citizens) in the GLP-1 rate class?"[18]

Q. WHAT WAS MR. NOLT'S ANSWER?

A. "The tariff would immediately re-classify any solar project rated over 400kWAC from GSSR-1 (a retail rate averaging 8.565 cents/ kWh the last 10 years) down to GSSR-2 (a wholesale LMP rate of and average of 3.238 cents per kWh). From an operational perspective, based on data from 5/18/24 - 5/18/25, using a PA solar array overlaid to LMP pricing. The energy revenue will decrease by 62%."

Q. ARE THERE OTHER PORTIONS OF MR. NOLT'S TESTIMONY THAT INDICATE SOLAR PROJECTS ARE CONCERNED WITH COMPENSATION AT GSSR-2?

A. Yes. Please see the excerpt below.

[18] Direct Testimony of Brett Nolt, p. 3

Q. HOW IS THE RATE THAT CUSTOMERS WILL BE CHARGED FOR ENERGY IN THE GSSR 2 TO BE CALCULATED?

A. Hourly RTP Energy Charge (This is the LMP) will include the following:

- *Capacity Charge*
- *Transmission Charge*
- *RTEP Charge*
- *Administrative Charge (this is the costs incurred by the company and its wholesale supplier to manage energy procurement and delivery)*
- *Gross Receipts Tax*

Q. WILL THIS METHODOLOGY BE THE SAME METHODOLOGY APPLIED TO CUSTOMERS WHO GENERATE ENERGY IN EXCESS OF WHAT THAN THEY CONSUME IN A YEAR?

A. No, customer generators will be paid only at the LMP for excess generation.

Q. DO YOU AGREE WITH MR. NOLT'S ASSESSMENT AND STATEMENT?

A. In comparing this answer to the point of view shared by Mr. Johnson in testimony and interrogatory responses, I find this to be a difficult topic to interpret with (1) differing views of local customer-generator value as it relates to capacity and transmission costs and (2) use of unclear evidence which is outside of the tariff. [19,20] By statutory mandate, customer-generators must be compensated at a retail value and this is the aim of the Company according to Rider B in the Company's Tariff:

> The customer-generator will receive a credit for each kilowatt-hour received by the Company up to the total amount of electricity delivered to the Customer during the billing period at the full retail rate, consistent with Commission regulations. On an annual basis, the Company will compensate the customer-generator for kilowatt-hours received from the customer-generator in excess of

[19] When asked about the assertion that net exports will not be compensated as capacity or for reducing transmission cost allocation, Mr. Nolt responded: "Based on a discovery question response from Nate Johnson SP-I-4 it was stated that solar generation is only paid at LMP. Capacity and Transmission (among other items) are not paid out for solar production kWh, even though solar production in real time does not use the transmission system and does have a capacity value. It differs from how users are charged in the GSSR-2 class."

[20] Citizens response to this topic on August 4, 2025: "The Company does not believe it is appropriate to incorporate any capacity or transmission impact into its analysis, however, because net-metered generation does not guarantee those savings and is economically disincentivized to export during peak demand periods. Please note that a customer generator on the GSSR-2 rate would see the benefit of a zero transmission and/or capacity obligation if it successfully offsets its on-site consumption during the relevant PJM peaks."

> the kilowatt hours delivered by Company to the customer-generator during the preceding year at the **"full retail value for all energy produced"** consistent with Commission regulations. The customer-generator is responsible for the customer charge, demand charge and other applicable charges under the applicable Rate Schedule.[21]

Q. WHY DO YOU RAISE THIS AS AN ISSUE?

A. Mr. Nolt may be overstating the impact of the proposed Billing Demand methodology on customer-generator compensation; meanwhile, Mr. Nolt's interpretations of Mr. Johnson's statements are understandable, but not supported by the tariff in my view. Additional clarity on this issue would be helpful, and I intend to ask the Company for more information. SP-I-1 Attachment A was an effective way to illustrate theoretical billing for a GSSR-2 customer with net load (*i.e.*, the customer receives more from the Company than it supplies to the Company). Obtaining a similar, theoretical workbook which would reflect the functioning of GSSR-2 billing/compensation to a customer-generator with net export (*i.e.*, the customer supplies more to the Company than the customer receives from the Company) and a negative (or zero) contribution to peak load for capacity and transmission charges would be helpful.

Q. WHAT ELSE MIGHT HELP WITH THIS ISSUE?

A. The Company and Mr. Nolt should focus on the tariff and ensure that the language of Rider B – Net Metering, p. 66 is clear that a customer-generator that is a net exporter to the system will receive a credit that includes "all charges of the appropriate rate schedule" as applied to the net kWhs of electricity that the customer-generator supplied to the Company. This very same clear language appears for net load customer-generators in paragraph 2 of Rider B.[22] Next, in the GSSR-2 Rider, while all components of a retail rate are listed, that is the energy charge, capacity charge, transmission charge, RTEP charge, e-factor, and administrative charge, greater clarity

[21] Citizens' Tariff, Rider B – Net Metering, p. 66 (emphasis added).
[22] *Id.*

on how the Company determines certain values within each charge when a customer-generator is a net exporter could be helpful. For example, in the GSSR-2 Capacity Charge, how does the Company determine a customer's fixed peak load capacity obligation (especially a customer that is a net exporter during this determination)? The tariff states "in accordance with the applicable PJM Agreements" which I believe could use more clarity.[23] I intend to seek further discovery on these points.

Q. WILL THE COMPANY'S PROPOSED BILLING DEMAND METHODOLOGY AFFECT RESIDENTIAL CUSTOMERS WITH DER?

A. No, not substantially. A vast majority of residential customers with DER have DER systems with output capacity of much less than 400 kW (most are order(s) of magnitude smaller) and accordingly they will remain in the GSSR-1 classification.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

[23] Citizens' Tariff, p. 39

OCA STATEMENT 5R

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	**)**	
v.	**)**	
Citizens' Electric Company of Lewisburg, PA	**)**	**Docket No. R-2025-3054394**
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EXHIBITS TO THE

REBUTTAL TESTIMONY

OF

ZACH TETI

ON BEHALF OF THE

PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

August 13, 2025

CURRICULUM VITAE OF ZACH TETI

PROFESSIONAL EXPERIENCE

Pennsylvania Office of Consumer Advocate • Harrisburg, PA • April 2025-Present • Senior Regulatory Analyst
Customized Energy Solutions • Philadelphia, PA • April 2024-September 2024 (Contract) • Compliance Analyst
Avangrid • Orange, CT • May 2021-April 2024 • Regulatory Analyst – FERC, ISO New England & New York ISO
Penn State University • University Park, PA • August 2019-May 2021 • Research Assistant – Energy Economics
TD Bank • Mount Laurel, NJ • February 2018-July 2019 • Assistant Vice President – Retail Lending Financial Analysis
JP Morgan Chase • Newark, DE • July 2013-February 2018
Budgeting, Forecasting and Analysis - Associate – Consumer Banking Technology • July 2017-February 2018
Financial Control – Associate & Analyst – International Trade Finance • July 2013-July 2017
Lancaster County Workforce Investment Board • Lancaster, PA • December 2012-May 2013 • Research Intern

EDUCATION & OTHER UNDERTAKINGS

Penn State University • University Park, PA • May 2021 • MS in Energy Economics
Millersville University • Millersville, PA • May 2013 • BA in Quantitative Economics, minor in Statistics
Curator for the Global Shapers Philadelphia Hub – World Economic Forum Initiative • September 2017-May 2021

COMPANY RESPONSE TO INTERROGATORY SP-II-5

SP-II-5

Please reference Citizens' St. No. 4, p. 17. Has Citizens conducted any studies or analyses of the effects of this tariff change on Citizens' default procurement of electricity based on its Default Service Plan ("DSP")? If yes, please provide all studies or analyses related to the same.

Response Provided By:
Nathan Johnson, President & CEO

Date: June 30, 2025 (original)
July 14, 2025 (revised)

Response:

July 14, 2025 Revisions:
The Company has revised the attachments ("SP-II-5 Attachment A" and "SP-II-5 Attachment B") provided with the original response to SP-II-5, and made revisions to the response below, highlighted in yellow after identifying a data error related to the AC-to-DC ratio of the model PV systems used.

Original Response with July 14, 2025 Revision Incorporated:

Yes, the Company has analyzed the impact of net metered energy on default service costs in two different ways:

1) The direct cost of purchased net-metered energy compared to the cost of purchasing the same volume of energy through the DSP.

2) The potential for net-metered generation to mitigate PJM Capacity, Transmission, and RTEP costs.

The purchase cost analysis can be found in the attachment titled "SP-II-5 Attachment A (REV)." It contains several comparisons, summarized in the table below:

Comparison	Description	Result
400kW	400kW$_{AC}$ Roof Mount SPV w/ no offset load, standard PVWatts® roof-mount parameters	~$27,000 increase in GSSR-1 costs annually.
Ex + Prop >400kW	Expected net-metered export purchases of existing and proposed systems with ≥400kW rated output capacity	~$88,000 increase in GSSR-1 costs annually.

3000kW	3MW$_{AC}$ Rack Mounted Tracking (w/ Backtracking) SPV, premium panels, standard PVWatts® parameters	~$230,000 increase in GSSR-1 costs annually.

The analysis of PJM cost mitigation can be found in the attachment titled "SP-II-5 Attachment B (REV)." It contains a ten year history of PJM Capacity and Transmission peak hours and hourly outputs from the same PVWatts® studies used in Attachment A (REV). For nearly half of the past decade's PJM Capacity and Transmission Peak hours, SPV output from either model was 20% or less of rated capacity, demonstrating the limited ability of net-metered SPV to mitigate PJM costs.

Additionally, while no quantitative analysis has been performed, basic market principles suggest that as the total volume of energy purchased decreases, the price-per-unit will increase. In essence, as more energy is purchased from net-metered exports, less is purchased through the DSP wholesale contract. This lowers the 'buying power' of the DSP while concentrating non- volumetric (Company and supplier admin costs, Capacity, Transmission, and RTEP) costs across a smaller total quantity purchased, increasing the cost per MWh of default supply.

Finally, as purchased net-metered energy creates net under collection of GSSR costs under the existing structure (where the customer generator receives the GSSR-1 price regardless of the generator's size), the resulting reconciliation in future periods through the E-factor inflates the cost of default supply which, in turn, inflates the purchased cost of future-period net-metered energy purchases. In short, net-metered customer-generators directly benefit from the price inflation that they cause in a compounding fashion that increases as more net-metered generation is installed.

The Company concludes from its analysis that 1) net-metered generation exports result in a significant increase to default supply costs and 2) its proposed tariff change will mitigate these increases by shifting large exporters to the GSSR-2 rate and corresponding reimbursement formula.

BILLING DEMAND PROPOSAL SUMMARY TABLE

	APPLICATION OF SCHEDULE	NET MONTHLY DISTRIBUTION RATE	GENERATION SUPPLY RATES
RS	Service supplied in accordance with Company's Residential Service Requirements contained in Rule 31, in Company's Rules and Regulations.[1]	$16.50 Customer Charge 4.506 cents per kWh for all kWh	GSSR-1[2]
GLP-1	This rate schedule is for small general light and power service at secondary voltage or at a higher available voltage at the option of the Customer.	$21.00 Customer Charge $4.52 per kilowatt for all kilowatts of the Billing Demand 1.164 cents per kWh for all kWh	GSSR-1 or GSSR-2[3, 4]
GLP-3	General light and power service for not less than 50 kilowatts of Billing Demand from available lines of three phase 230 volts or at a higher available voltage at the option of the Customer.	$100.00 Customer Charge $6.91 per kilowatt for all kilowatts of the Billing Demand 1.221 cents per kWh for 30 kWh per kilowatt of the Billing Demand 0.133 cents per kWh for all additional kWh	GSSR-1 or GSSR-2
MBL	This schedule applies to street lighting controlled by Company when proper underground cables and lighting standards are available in the Borough of Lewisburg, Pennsylvania.	$6.72 for each meter $6.97 for each light post connected to the meter	GSSR-1
OL	Outdoor dusk to dawn lighting service to any customer when such service can be supplied from existing overhead or underground secondary supply lines.	Other	Other

Notes:

1. RULE 31. RESIDENTIAL SERVICE REQUIREMENTS
   (a) Company's Residential Service, Schedule RS, except as otherwise provided herein, applies to the supply of single-phase electric service through one meter to a single private dwelling unit and its appurtenant detached buildings such as a garage, stable, barn, etc. A separate dwelling unit shall consist of three or more rooms having separate bathroom, kitchen and living room.
   (b) The schedule applies to service for:
      (1) A separate dwelling unit in an apartment house, but not the halls, basement, or other portions of such building common to more than one such unit.
      (2) A private dwelling in which space is only occasionally used in connection with the conduct of a business or profession by a person residing therein.
2. For all RS customers, the generation charge is GSSR-1.
3. Customers with monthly Billing Demands under 400 kW for each of the prior 12 months will be applied to the GSSR-1. Customers with a monthly Billing Demand of 400 kW or more during any month in the last 12 months will be applied to the GSSR-2.
4. GSSR-1 and GSSR-2 are applied to customers that take Default Service. For GLP-1, GLP-3 customers, the service rate is determined by Billing Demand (see Note 3).
   (a) GSSR-1 is procurement-based on "Purchased Power Costs for the compliance period incurred by the Company to acquire generation supply."

(b) GSSR-2 is more direct, or market-based: (example of a component: "GSSR-2 Energy Charge per kWh: The product of the actual real-time PJM West Hub Locational Marginal Prices ("LMPs") for each hour of the billing month expressed in cents per kWh (including the Distribution Loss Adjustment), times the customer's actual energy use during each hour of the billing month."

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No. R-2025-3054394
	:	
Citizens' Electric Co. of Lewisburg, PA	:	

VERIFICATION

I, Zachary F. Teti, hereby state that the facts above set forth in my Rebuttal Testimony, OCA Statement No. 5R, are true and correct to the best of my knowledge, information, and belief and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa.C.S. § 4904 (relating to unsworn falsification to authorities).

DATED: August 13, 2025

Signature: */s/ Zachary F. Teti*
Zachary F. Teti

Address: Office of Consumer Advocate
555 Walnut Street
Harrisburg, PA 17101

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
v.	)	**R-2025-3054394**
Citizens' Electric Company of Lewisburg, PA	)	

Surrebuttal Testimony of

Greg R. Meyer

OCA Statement 1SR

On behalf of

Pennsylvania Office of Consumer Advocate

Date Served: August 28, 2025

BRUBAKER & ASSOCIATES, INC.

Project 11858

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
v.	)	**R-2025-3054394**
Citizens' Electric Company of Lewisburg, PA	)	

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BEFORE THE
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Pennsylvania Public Utility Commission	)	
v.	)	**R-2025-3054394**
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Surrebuttal Testimony of Greg R. Meyer

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Greg R. Meyer. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q ARE YOU THE SAME GREG R. MEYER WHO PREVIOUSLY FILED DIRECT TESTIMONY ON JULY 15, 2025 AND REBUTTAL TESTIMONY ON AUGUST 13, 2025, IN THIS PROCEEDING?

A Yes, I am.

Q ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?

A I am appearing on behalf of the Pennsylvania Office of Consumer Advocate ("OCA").

Q PLEASE GIVE A BRIEF OVERVIEW OF YOUR SURREBUTTAL TESTIMONY.

A My Surrebuttal Testimony will address the following issues:

- I recommend the Pennsylvania Public Utility Commission ("Commission") not recognize a regulatory asset for the unrecovered rate case expense.
- I continue to support a revenue adjustment for Citizens' Electric Company of Lewisburg, PA ("Citizens").
- I support a Citizens labor adjustment.
- I recommend the Commission adjust Accounts 593 and 920 expenses.
- I recommend the Commission adjust Citizens' expenses to remove lobbying activities.
- I support an adjustment to uncollectible expense.

My silence regarding any issue should not be construed as an endorsement of or acquiescence to positions advanced by Citizens.

RATE CASE EXPENSE REGULATORY ASSET

Q IS CITIZENS CONTINUING TO REQUEST A REGULATORY ASSET FOR THE RECOVERY OF RATE CASE EXPENSE?

A Yes, and I am still opposed to granting recovery on the unamortized rate case expense balance. I am proposing, similar to the witnesses for the Bureau of Investigation and Enforcement and the Pennsylvania Office of Small Business Advocate, that rate case expense be normalized over a certain rate case interval. By normalizing rate case expense over a rate case interval there is no need to establish a regulatory asset.

Q CITIZENS ARGUES THAT THE UNAMORTIZED BALANCE IS REQUIRED TO COMPENSATE CITIZENS' SHAREHOLDERS FOR PROVIDING FUNDS NECESSARY TO FILE A RATE CASE AND RECOVER THOSE EXPENSES OVER A MULTI-YEAR PERIOD.[1] PLEASE COMMENT.

A What Citizens fails to recognize is that there are benefits to Citizens' shareholders from filing a rate case. In filing a rate case, Citizens' shareholders are given an opportunity to have all of its operations reviewed and just and reasonable rates established to collect its cost of service. This review includes a detailed analysis of current market conditions to establish a reasonable rate of return. Given these benefits to Citizens' shareholders, it is entirely fair to normalize rate case expense and deny the establishment of a regulatory asset.

Q IN ITS REBUTTAL TESTIMONY, CITIZENS ARGUES THAT THE UNAMORTIZED BALANCE OF RATE CASE EXPENSE IS SIMILAR TO THE INCLUSION OF MATERIALS AND SUPPLIES.[2] DO YOU AGREE?

A No. I do not think the arguments by Citizens trying to compare the ratemaking treatment of materials and supplies to the recovery of rate case expense is persuasive. Including materials and supplies in rate base recognizes that a utility should include a certain level of materials and supplies in its inventory to timely make repairs to the utility system to maintain reliable service. Given this expenditure of funds, it is necessary to provide a return on those inventory levels. That contrasts with the recovery of a recurring expense

[1] *See* the Rebuttal Testimony of Howard Gorman at page 6, lines 2-5.
[2] *Ibid.,* lines 6-8.

(not annually) for filing a rate case. Rate case expense recovery should be spread out over the rate case interval. This results in an even recovery of rate case expense from Citizens' ratepayers and assigns some of the benefits of rate case expenses to shareholders if they indeed prefunded those costs with shareholder funds.

RATE REVENUES

Q IS CITIZENS STILL SUPPORTING A FIVE-YEAR AVERAGE USAGE PER CUSTOMER TO ANNUALIZE REVENUES?

A Yes. Citizens continues to argue that usage per customer has decreased and, therefore, the use of a five-year average usage methodology is appropriate. Citizens' witness Howard Gorman states the following:

> As shown in Table HSG-3 below, the major rate classes have each shown marked declines in annual kWh usage per customer in recent periods. In fact, the 2023 and 2024 actual numbers are well below the 5-year averages that were used in the Company's forecast.[3]

Q ARE YOU AWARE OF ANY DATA THAT COULD EXPLAIN THE REASON WHY 2023 AND 2024 USAGE HAS DECLINED?

A Yes. First let me explain that Citizens' rate classes are affected by winter weather. I have included Table GRM-SR1 (Citizens) that shows the historic usage for the Residential class from 2020-2024.

[3] *Ibid.,* at page 8, lines 2-5.

Table GRM-SR1 (Citizens)

Historical Monthly Usage

Month	2020	2021	2022	2023	2024
	(1)	(2)	(3)	(4)	(5)
January	9,799,772	10,403,845	10,033,795	10,434,514	9,326,803
February	9,639,089	11,159,231	12,451,098	9,574,263	9,611,387
March	7,951,952	8,859,619	8,549,760	7,832,689	7,494,805
April	7,098,046	6,688,720	7,443,921	6,750,083	6,769,432
May	6,317,409	5,460,233	5,717,775	5,168,066	5,134,716
June	5,678,091	5,827,965	5,548,259	5,045,620	5,526,480
July	6,686,627	6,489,233	6,376,805	5,905,329	6,716,368
August	7,631,571	6,717,882	7,168,264	6,512,217	6,806,209
September	6,419,184	6,728,662	6,361,446	6,122,476	5,667,038
October	4,936,964	4,900,850	5,073,428	4,930,746	4,785,266
November	6,151,722	6,200,250	6,187,734	6,002,347	5,566,791
December	8,029,584	8,335,509	8,773,308	8,171,977	8,317,039
Total	86,340,011	87,771,999	89,685,593	82,450,327	81,722,334

Source:
[1]Company Response to OCA Data Request 2-25 Attachment A

As can be seen from the table above, the four highest usage months are January, February, March, and December. Clearly this supports the theory that the Residential class is winter weather usage sensitive.

Q IS THERE A STANDARD MEASUREMENT TO ACCOUNT FOR WINTER WEATHER-SENSITIVE CUSTOMERS' USAGE?

A Yes. Heating Degree Days ("HDD") are a standard measurement of winter weather intensity. The theory behind HDD is the colder the weather in the winter, customers will use more electricity for space heating their homes. Colder winter weather translates

into higher HDDs for that year. I have prepared Table GRM-SR2 (Citizens) below that shows the annual HDDs ranked lowest to highest for the last 25 years dating back to 2000.

Table GRM-SR2 (Citizens)

Heating Degree Days

Year	HDD 65	Rank
2000	6,086	17
2001	5,735	8
2002	5,836	11
2003	3,532	1
2004	6,000	15
2005	6,161	19
2006	5,362	4
2007	5,936	14
2008	6,186	21
2009	6,161	20
2010	5,792	9
2011	5,852	12
2012	5,303	2
2013	6,300	24
2014	6,733	25
2015	6,225	23
2016	5,903	13
2017	5,810	10
2018	6,202	22
2019	6,016	16
2020	5,656	7
2021	5,586	6
2022	6,090	18
2023	5,303	2
2024	5,386	5
5 Year Ave	5,604	
10 Year Ave	5,818	
15 Year Ave	5,877	
20 Year Ave	5,898	
25 Year Ave	5,806	

Source:

National Centers for Environmental Information climate data for Station USC00364976 (LEWISBURG, PA US).

As can be seen from the table, the HDDs for 2023 and 2024 are significantly lower than the other 20 years. In fact, except for an uncharacteristic HDD total in 2003, 2023 and 2024 would have had the 1st and 4th lowest HDD totals recorded dating back to 2000. Establishing customer usage from a five-year average that includes these abnormal winter weather patterns will understate revenues going forward. I, therefore, continue to support a ten-year average usage for annualizing revenues.

LABOR

Q HAVE YOU READ CITIZENS' REBUTTAL TESTIMONY ADDRESSING LABOR EXPENSES?

A Yes. I have read the Rebuttal Testimony of Citizens' witness Nathan Johnson discussing payroll increases.

Q WHAT LEVEL OF PAYROLL INCREASE IS CITIZENS SEEKING IN THIS RATE CASE?

A Citizens is proposing to increase Operation and Maintenance ("O&M") payroll expense by $199,788 from 2024 to 2026 Fully Projected Future Test Year ("FPFTY") of approximately 19.6%.

Q DID CITIZENS PROVIDE ANY REASONS FOR THE PROPOSED INCREASE IN PAYROLL EXPENSE?

A Yes, Mr. Johnson explains that two hires are to replace retiring line technicians following 2026. Mr. Johnson goes on to explain the two hires are apprentices for the

line technicians and the apprenticeship takes four to five years to complete. During this four-to-five-year period, Citizens' workforce is actually overstaffed as the apprenticeships are working while the line technicians have not retired. Mr. Johnson further states that several of Citizens' positions required adjustments to better reflect market conditions.

Q HAVE YOU ANALYZED CITIZENS' WORKFORCE TO DETERMINE IF CITIZENS' WAGES ARE COMPETITIVE WITH THE MARKET.

A I have looked at two different workforce metrics. First, I looked at the employee levels at Citizens since 2020. Second, I analyzed the employee tenure of Citizens' employees.

Q PLEASE DESCRIBE THE LEVEL OF EMPLOYEES AT CITIZENS SINCE 2020.

A I have prepared Table GRM-SR3 (Citizens) that shows the annual level of employees at Citizens.

Table GRM-SR3 (Citizens)

Employee Levels

Year	Employee Count
2020	16
2021	18
2022	19
2023	18
2024	18
FTY	19
FPFTY	20

Source:
2020 to 2024 from annual reports;
TYs from OCA 7-12

As the table above reveals, the number of employees on Citizens' workforce is steady and shows a two person increase in 2025-2026. I assume the two-person increase is the increase in employees to replace the line technicians expected to retire following 2026. The steady workforce numbers suggest that Citizens does not have problems attracting employees to work for them.

Q PLEASE DISCUSS CITIZENS' EMPLOYEE TENURE ANALYSIS.

A In Response to OCA Data Request 7-16, Citizens reported that the average Citizens' employee tenure was 12.8 years. Excluding a brand-new hire with approximately 10 months experience raises the Citizens' employee tenure to 13.5 years. This level of tenure is an important metric in that it indicates that Citizens' employees view positively their total compensation package to work for Citizens. Having an average tenure of

12.8-13.5 years does not indicate dissatisfaction with the wages paid to Citizens' employees. I have summarized this response in Table GRM-SR4 (Citizens) below.

Table GRM-SR4 (Citizens)

Employee Tenure

Employee	Tenure
4003	32
4006	39
4010	32
4012	3
4015	7
4018	9
4021	7
4024	22
4025	22
4029	18
4033	10
4034	10
4035	6
4036	6
4037	4
4038	4
4039	2
4040	1
Average	12.8
Average (No 4040)	13.5

Source:

Company Response to OCA Data Request 7-16.

Q DO YOU HAVE ANY FURTHER INFORMATION ABOUT WAGE INCREASES GRANTED TO CITIZENS' EMPLOYEES OVER THE YEARS?

A Yes, I have compiled Table GRM-SR5 (Citizens) below that shows the wage increase information that Citizens includes in its annual reports to the Commission.

Table GRM-SR5 (Citizens)

Wage Scale Changes

Year	Wage Change
2009	3.5% COLA effective 1/1/2009, and merit increase throughout the year averaging 0.75%, Estimated annual effect $44,000.
2010	No COLA increases this year merit increase this year averaging 1.3%. estimated annual effect $14,560.
2011	4% COLA effective 01/12 and merit increases throughout the year averaging 1.67%, Estimated annual effect $63,000.
2012	3% COLA effective 01/12 and merit increases throughout the year averaging 1.8%. The labor decreased $22,000. This net labor decrease is a result of staff reduction due to retirement.
2013	3% COLA effective 01/2013 and merit increases throughout the year averaging 1.3%. Labor increased $47,000.
2014	3% COLA effective 01/2014 and merit increases throughout the year increased labor $65,000.
2015	3% COLA effective 01/2015 and merit increases throughout the year increased labor $70,941.
2016	3% COLA effective 01/2016 and merit increases throughout the year increased labor $91,173.
2017	3% COLA effective 01/2017. Merit increases throughout the year increased labor $22,268.
2018	3% COLA effective 01/2018, merit increases throughout the year, and additional staffing to replace retiring personnel increased labor $120,448.
2019	3% COLA effective 01/2019, merit increases throughout the year, and additional staffing to replace retiring personnel increase labor $17,151.70.
2020	3% COLA effective 1/2020, merit increases throughout the year increased labor $272.
2021	3% COLA effective 1/2021, merit increases throughout the year increased labor $7,817.
2022	4.5% COLA effective 1/2022, merit increases throughout the year increased labor $85,671.
2023	Six percent COLA effective 1/1/2023, merit increases throughout the year increased labor $129,027.
2024	Four percent COLA effective 1/1/2024, merit increases throughout the year increased labor $43,095.

Source:
[1] 2009 to 2024 annual reports to the Pennsylvania Public Utility Commission

The table above reveals that since 2009 the predominant wage increase granted to Citizens' employees has been 3% with additional merit increases above the 3%. I would also note that the average wage increase over those years as reported by Citizens is approximately $50,000.

Q DO YOU CONTINUE TO SUPPORT THE 4% WAGE INCREASE YOU APPLIED TO THE CITIZENS' WAGES?

A Yes, and I would also recognize the two employees who are to be hired as apprenticeship employees.

NON-LABOR ADJUSTMENT TO
MAINTENANCE OF OVERHEAD LINES – ACCOUNT 593

Q HAVE YOU REVIEWED THE REBUTTAL TESTIMONY OF CITIZENS' WITNESS NATHAN JOHNSON REGARDING YOUR ADJUSTMENT TO THE NON-LABOR PORTION OF MAINTENANCE OF OVERHEAD LINES?

A Yes, I have. Mr. Johnson notes the activities that make up the projected 57.5% increase over the Historic Test Year ("HTY") 2024 cost.[4] He also provides examples of how Citizens proposes to hold down costs.[5]

Q HOW DO YOU RESPOND?

A When we are looking at a projected increase of this magnitude ($240,947 greater than HTY 2024) one should expect concern for cost control, especially given that the risks

[4] *See* the Rebuttal Testimony of Nathan Johnson at pages 7-8.
[5] *Ibid.*, at page 9.

to Citizens' overhead lines are not new or sudden. All electric utilities incur these types of costs and have for many years. It would be normal to expect some growth in these costs, but the level proposed by Citizens is far beyond what we have seen in the past. From 2020 to 2024 we only saw $83,680 growth in costs – a compound annual growth rate of 5.73%.[6] Based on this pattern, the projected increases proposed by Citizens of 20.19% and 31.07% are staggering and not appropriate for inclusion in expense. I still support a non-labor expense of $468,197 for this account, a reduction to Citizens' expense of $191,571.

NON-LABOR ADJUSTMENT TO ADMINISTRATIVE AND GENERAL ("A&G") SALARIES – ACCOUNT 920

Q HAVE YOU REVIEWED THE REBUTTAL TESTIMONY OF CITIZENS' WITNESS KATHY STAUDER AS IT RELATES TO YOUR ADJUSTMENT TO THE A&G SALARIES ACCOUNT?

A Yes, I have. Ms. Stauder notes that these cost increases represent benefit costs that follow salaries and that $20,508 of the $88,472 increase over the HTY 2024 relates to the overlapping of positions.[7]

Q HOW DO YOU RESPOND?

A I have previously discussed my concerns with the substantial increase that Citizens has projected to labor expense. To the extent that these non-labor charges are driven by

[6]Data from Exhibit (HSG-1), Schedule C from last case and the present case. Summarized in Table GRM-7 (Citizens) on page 17 of my Direct Testimony.

[7]*See* the Rebuttal Testimony of Kathy Stauder at page 7, lines 5-10.

Citizens' inflated labor projections, I would also oppose building in inflated estimates for these costs.

As it concerns the building in an additional cost for having two people in Ms. Stauder's position at the same time, I maintain that this is a cost best borne by the shareholders. These are costs that do not reflect normal conditions. When we encounter non-normal conditions in operations in test years, the appropriate response is to normalize the cost, either by removing the non-normal cost, or in cases of unexpected and extremely large costs, proposing a normalizing adjustment to spread those costs over multiple years. This does not appear to meet the criteria for spreading over multiple periods and, so, my recommendation is that these costs are inappropriate for including in the revenue requirement. Customers should not be forced to pay for two people to fill the role at the same time. For these reasons, I remain steadfast in my position that the appropriate level of non-labor A&G Salaries expense is $404,145 and that Citizens' expense be reduced by $61,739.

LOBBYING

Q HAVE YOU REVIEWED THE REBUTTAL TESTIMONY OF KATHY STAUDER RELATED TO LOBBYING?

A Yes, I have. Ms. Stauder claims that only $38 represents the lobbying portion of the Energy Association of Pennsylvania ("EAP").[8]

[8] *Ibid.*, at page 5, lines 2-4.

Q HOW DO YOU RESPOND?

A A review of the organization's webpage clearly emphasizes EAP's lobbying and advocacy roles. Often trade organizations like EAP use the Internal Revenue Service's ("IRS") definition of lobbying that is much more narrowly defined and would tend to exclude advocacy from the definition. EAP appears to emphasize its benefits to utilities, rather than customers. On the "Who We Are" page of the EAP website, the organization states:

> "With roots dating back to 1908, the Energy Association of Pennsylvania is well-established as the voice of Pennsylvania's electric and natural gas utilities. The Association is an advocate for its members on policy issues before the General Assembly, the Public Utility Commission, and various other state governmental agencies."[9]

This type of advocacy should be borne by the shareholders who are clearly the beneficiaries of the EAP's work. I remain convinced that the full amount of the EAP membership should be excluded.

UNCOLLECTIBLES

Q HAVE YOU REVIEWED THE REBUTTAL TESTIMONY OF HOWARD GORMAN REGARDING UNCOLLECTIBLES?

A Yes, I have. Mr. Gorman asserts that I found a trend in uncollectibles rates when I compared revenues with net write-offs.[10] He then goes on to say that the 0.167% rate used by Citizens "is a reasonable continuation of this trend."[11]

[9] https://www.energypa.org/who-we-are/ last accessed August 23, 2025.
[10] *See* the Rebuttal Testimony of Howard Gorman at page 8, lines 15-16.
[11] *Ibid.*, at page 9, line 1.

Q DO YOU AGREE WITH MR. GORMAN?

A Reviewing my Table GRM-5 (Citizens), I do not see any such trend that could be extrapolated to support a 0.167% uncollectibles rate. The numbers that I showed fluctuated up and down and no real trend exits. I, therefore, opted to normalize by using a five-year average to develop a reasonable expected rate of uncollectibles. The level supported by Citizens exceeds anything we have seen in recent history and should not be adopted.

CONCLUSION

Q DOES THIS CONCLUDE YOUR SURREBUTTAL TESTIMONY?

A Yes, it does.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No. R-2025-3054394
	:	
Citizens' Electric Co. of Lewisburg, PA	:	

VERIFICATION

I, Greg R. Meyer, hereby state that the facts above set forth in my Surrebuttal Testimony, OCA Statement No. 1SR, are true and correct to the best of my knowledge, information, and belief and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa.C.S. § 4904 (relating to unsworn falsification to authorities).

DATED: August 28, 2025

Signature: /s/ Greg R. Meyer
Greg R. Meyer

Address: Brubaker Associates Inc.
16690 Swingley Ridge Road, Suite 140
Chesterfield, MO 63017

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
v.	)	**R-2025-3054393**
Valley Energy, Inc.	)	

Surrebuttal Testimony of

Greg R. Meyer

OCA Statement 1SR

On behalf of

Pennsylvania Office of Consumer Advocate

Date Served: August 28, 2025

BRUBAKER & ASSOCIATES, INC.

Project 11858

BEFORE THE
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BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
v.	)	**R-2025-3054393**
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Surrebuttal Testimony of Greg R. Meyer

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Greg R. Meyer. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q ARE YOU THE SAME GREG R. MEYER WHO PREVIOUSLY FILED DIRECT TESTIMONY ON JULY 15, 2025 AND REBUTTAL TESTIMONY ON AUGUST 13, 2025, IN THIS PROCEEDING?

A Yes, I am.

Q ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?

A I am appearing on behalf of the Pennsylvania Office of Consumer Advocate ("OCA").

Q PLEASE GIVE A BRIEF OVERVIEW OF YOUR SURREBUTTAL TESTIMONY.

A My Surrebuttal Testimony will address the following issues:

- I recommend a depreciation expense adjustment.

- I recommend the Pennsylvania Public Utility Commission ("Commission") not recognize a regulatory asset for the unrecovered rate case expense.
- I support a Valley Energy, Inc. ("Valley") labor adjustment.
- I recommend the Commission adjust Account 880's expense level.

My silence regarding any issue should not be construed as an endorsement of or acquiescence to positions advanced by Valley.

DEPRECIATION EXPENSE

Q HAS VALLEY AGREED TO A CHANGE IN ITS ANNUALIZED DEPRECIATION EXPENSE BASED ON YOUR DIRECT TESTIMONY?

A Yes. Valley has reduced its annualized depreciation expense to eliminate depreciation expense for Account 391 – Office Furniture & Equipment.

Q DOES THIS CHANGE REMOVE ALL ISSUES YOU HAVE IDENTIFIED IN YOUR DIRECT TESTIMONY WITH VALLEY'S ANNUALIZED DEPRECIATION EXPENSE?

A No. I continue to support a depreciation change for Account 396 – Power Operated Equipment.

Q PLEASE EXPLAIN WHY YOU ARE RECOMMENDING A DEPRECIATION RATE CHANGE FOR ACCOUNT 396.

A At the end of the 2026 Fully Projected Future Test Year ("FPFTY"), Account 396 net book value will be negative $199. A negative net book value indicates that assets contained in Account 396 have been fully depreciated. Any future depreciation expense

charged to this account will only increase the negative net plant value assuming no new plant investment is made in Account 396. I would note that annual depreciation expense for Account 396 is $58,744 according to Valley. To address this negative net plant value issue, I am proposing a new depreciation rate for Account 396.

Q HOW DID VALLEY RESPOND TO YOUR PROPOSED CHANGE IN DEPRECIATION EXPENSE FOR ACCOUNT 396?

A Valley is opposed to changing the deprecation rate for Account 396. Valley presents the following arguments for why the deprecation rate for Account 396 should not be changed:

> "He [Mr. Meyer] did not present a depreciation study to support extending the depreciable life of this item."[1]

> "…ignores any capital spending the Company will do to replace this fully depreciated equipment."[2]

Q PLEASE DISCUSS THE ARGUMENT THAT YOU DID NOT PRESENT A DEPRECIATION STUDY.

A I assume the Valley witness is referring to the fact that I did not specifically perform a depreciation study for Account 396. That is correct since I merely took the 2026 depreciation expense for this account and spread it over the three-year rate case interval proposed by Valley. I would contend that a depreciation study was not necessary for that adjustment. However, I have since incorporated Valley's argument about plant additions and I will recommend a new depreciation rate.

[1] *See* the Rebuttal Testimony of Howard S. Gorman at page 7, lines 14-15.
[2] *Ibid*., lines 17-18.

Q PLEASE DISCUSS THE CONCERN RAISED BY MR. GORMAN CONCERNING NEW PLANT ADDITIONS.

A I agree that my original position did not recognize plant additions during the time the new rates will be in effect for this rate case because Valley did not propose any additions for 2025 or 2026. I have since developed a new scenario to support a new depreciation rate that includes annual plant additions.

Q PLEASE DISCUSS YOUR NEW ANALYSIS BASED ON MR. GORMAN'S REBUTTAL TESTIMONY.

A Before I address plant additions as raised by Mr. Gorman, I would like to show what the impact would be on the net plant value in Account 396 during the rate case interval if the depreciation rate (11.76%) is not changed.

I have prepared Table GRM-SR1 (Valley) that shows what the net plant value would be if no plant additions occurred during the three-year rate case interval.

Table GRM-SR1 (Valley)

Account 396 Scenario 1

Year	Ending Plant[1] (1)	Accumulated Depreciation Reserve[2] (2)	Plant Additions (3)	Depreciation Expense[3] (4)	Net Plant (5) = (1) - (2)
				11.76%	
2024	$ 499,528	$ 382,238	$ -	$ 48,647	$ 117,290
2025	$ 499,528	$ 440,982	$ -	$ 58,744	$ 58,546
2026	$ 499,528	$ 499,727	$ -	$ 58,744	$ (199)
2027	$ 499,528	$ 558,471	$ -	$ 58,744	$ (58,943)
2028	$ 499,528	$ 617,216	$ -	$ 58,744	$ (117,688)

Sources and Notes:

[1]2024 value from Company Schedule C3; following values are calculated as the previous ending plant plus the additions in Column 3.

[2]2024 value from Company Schedule C3; following values are calculated as the previous accumulated depreciation reserve plus that year's depreciation expense.

[3]2024 value from Company Schedule C3; following values are calculated as ending plant of previous year x the depreciation rate from similar accounts on Company Schedule C3 + a half year convention for additions in that year.

As can be seen from Table GRM-SR1 (Valley) above, the net plant value decreases from a negative $199 in 2026 to a negative $117,688 in 2028.

Q WHAT IMPACT WOULD PLANT ADDITIONS HAVE ON THIS ANALYSIS AND WHAT LEVEL OF PLANT ADDITIONS ARE YOU PROPOSING?

A I have prepared Table GRM-SR2 (Valley) that shows the historic plant additions/retirements for Account 396 dating back to 2015.

Table GRM-SR2 (Valley)

Account 396 Plant

Year	Additions	Retirements
2015	$ 74,195	$ -
2016	$ 1,214	$ -
2017	$ -	$ -
2018	$ -	$ -
2019	$ 110,377	$ 37,348
2020	$ 72,220	$ -
2021	$ 1,284	$ -
2022	$ -	$ -
2023	$ 51,721	$ -
2024	$ 28,666	$ -
Average	$ 33,968	$ 3,735

Source:
Valley Energy Annual Reports from 2015 to 2024.

As can be seen from Table GRM-SR2 (Valley) above, the total plant additions for Account 396 are approximately $400,000 since 2015. I have calculated a ten-year average of $33,968 annual plant additions.

Including those annual plant additions in the analysis still reveals that a negative net plant balance would occur at the end of the three-year rate case interval proposed by Valley. I have prepared Table GRM-SR3 (Valley) to show the effects on Account 396's net plant balance with plant additions and the current depreciation rate of 11.76%.

Table GRM-SR3 (Valley)

Account 396 Scenario 2

Year	Ending Plant[1] (1)	Accumulated Depreciation Reserve[2] (2)	Plant Additions[3] (3)	Depreciation Expense[4] (4)	Net Plant (5) = (1) - (2)
				11.76%	
2024	$ 499,528	$ 382,238	$ -	$ 48,647	$ 117,290
2025	$ 499,528	$ 440,982	$ -	$ 58,744	$ 58,546
2026	$ 499,528	$ 499,727	$ -	$ 58,744	$ (199)
2027	$ 533,496	$ 560,469	$ 33,968	$ 60,742	$ (26,973)
2028	$ 567,463	$ 625,205	$ 33,968	$ 64,736	$ (57,742)

Sources and Notes:

[1]2024 value from Company Schedule C3; following values are calculated as the previous ending plant plus the additions in Column 3.

[2]2024 value from Company Schedule C3; following values are calculated as the previous accumulated depreciation reserve plus that year's depreciation expense.

[3]Plant Additions are the 10 year average of plant additions for Account 396 per Valley Energy's annual reports from 2015 to 2024. See Table GRM-SR2 (Valley) for details.

[4]2024 value from Company Schedule C3; following values are calculated as ending plant of previous year x the depreciation rate from Company Schedule C3 + a half year convention for additions in that year.

As can be seen from Table GRM-SR3 (Valley) above, the negative net plant balance ($57,742) still exists with the budgeted plant additions of $33,968 for both 2027 and 2028. The negative net plant balance is still excessive, even assuming plant additions in 2027 and 2028, and the depreciation rate for Account 396 should be modified.

Q WHAT DEPRECIATION RATE DO YOU RECOMMEND FOR ACCOUNT 396 FOR PURPOSES OF THIS RATE CASE?

A I recommend a deprecation rate of 6.67% for Account 396.

Q WHAT IS THE BASIS FOR YOUR RECOMMENDATION?

A A depreciation rate of 6.67% is a common depreciation rate for Valley Administrative and General plant accounts.[3]

Q HAVE YOU PERFORMED AN ANALYSIS ON WHAT A DEPRECIATION RATE OF 6.67% WOULD HAVE ON THE NET PLANT BALANCE OF ACCOUNT 396?

A I have prepared a similar analysis that I have previously prepared and included as Tables GRM-SR1 and SR3 (Valley). I am including the results of that analysis in Table GRM-SR4 (Valley).

[3] *See* Exhibit_(HSG-1), Schedule C3, page 2.

Table GRM-SR4 (Valley)

Account 396 Scenario 3

Year	Ending Plant[1] (1)	Accumulated Depreciation Reserve[2] (2)	Plant Additions[3] (3)	Depreciation Expense[4] (4)	Net Plant (5) = (1) - (2)
				6.67%	
2024	$ 499,528	$ 382,238	$ -	$ 48,647	$ 117,290
2025	$ 499,528	$ 440,982	$ -	$ 58,744	$ 58,546
2026	$ 499,528	$ 474,301	$ -	$ 33,319	$ 25,227
2027	$ 533,496	$ 508,752	$ 33,968	$ 34,451	$ 24,743
2028	$ 567,463	$ 545,469	$ 33,968	$ 36,717	$ 21,994

Sources and Notes:

[1]2024 value from Company Schedule C3; following values are calculated as the previous ending plant plus the additions in Column 3.

[2]2024 value from Company Schedule C3; following values are calculated as the previous accumulated depreciation reserve plus that year's depreciation expense.

[3]Plant Additions are the 10 year average of plant additions for Account 396 per Valley Energy's annual reports from 2015 to 2024. See Table GRM-SR2 (Valley) for details.

[4]2024 and 2025 values from Company Schedule C3; following values are calculated as ending plant of previous year x the depreciation rate from similar accounts on Company Schedule C3 + a half year convention for additions in that year.

Table GRM-SR4 (Valley) above shows that by using a deprecation rate of 6.67% for Account 396, there will be an approximate positive net plant value of $21,994 at the end of the rate case interval proposed by Valley.

I would note that a positive net plant value of $21,994 still reflects the collection of a significant portion of the plant additions in those two years ($45,942 or 68%) in

between rate cases.[4] I would contend that a lesser depreciation rate could be justified for Account 396.

RATE CASE EXPENSE REGULATORY ASSET

Q IS VALLEY CONTINUING TO REQUEST A REGULATORY ASSET FOR THE RECOVERY OF RATE CASE EXPENSE?

A Yes, and I am still opposed to granting recovery on the unamortized rate case expense balance. I am proposing, similar to the witnesses for the Bureau of Investigation and Enforcement and the Pennsylvania Office of Small Business Advocate, that rate case expense be normalized over a certain rate case interval. By normalizing rate case expense over a rate case interval there is no need to establish a regulatory asset.

Q VALLEY ARGUES THAT THE UNAMORTIZED BALANCE IS REQUIRED TO COMPENSATE VALLEY'S SHAREHOLDERS FOR PROVIDING FUNDS NECESSARY TO FILE A RATE CASE AND RECOVER THOSE EXPENSES OVER A MULTI-YEAR PERIOD.[5] PLEASE COMMENT.

A What Valley fails to recognize is that there are benefits to Valley's shareholders from filing a rate case. In filing a rate case, Valley's shareholders are given an opportunity to have all of its operations reviewed and just and reasonable rates established to collect its cost of service. This review includes a detailed analysis of current market conditions to establish a reasonable rate of return. Given these benefits to Valley's shareholders,

[4] ($33,968 + $33,968 of plant additions) - $21,994 of remaining net plant = $45,942 already collected portion of additions.

[5] *See* the Rebuttal Testimony of Howard Gorman at page 4, lines 20-23.

it is entirely fair to normalize rate case expense and deny the establishment of a regulatory asset.

Q IN ITS REBUTTAL TESTIMONY, VALLEY ARGUES THAT THE UNAMORTIZED BALANCE OF RATE CASE EXPENSE IS SIMILAR TO THE INCLUSION OF MATERIALS AND SUPPLIES.[6] DO YOU AGREE?

A No. I do not think the arguments by Valley trying to compare the ratemaking treatment of materials and supplies to the recovery of rate case expense is persuasive. Including materials and supplies in rate base recognizes that a utility should include a certain level of materials and supplies in its inventory to timely make repairs to the utility system to maintain reliable service. Given this expenditure of funds, it is necessary to provide a return on those inventory levels. That contrasts with the recovery of a recurring expense (not annually) for filing a rate case. Rate case expense recovery should be spread out over the rate case interval. This results in an even recovery of rate case expense from Valley's ratepayers and assigns some of the benefits of rate case expenses to shareholders if they indeed prefunded those costs with shareholder's funds.

[6] *Ibid.,* at page 5, lines 1-5.

DISTRIBUTION EXPENSES – ACCOUNT 880

Q HAVE YOU REVIEWED THE REBUTTAL TESTIMONY OF VALLEY WITNESS EDWARD E. ROGERS AS IT RELATES TO YOUR ADJUSTMENT TO EXPENSES IN ACCOUNT 880 – OTHER DISTRIBUTION EXPENSES?

A Yes, I have. Mr. Rogers makes several claims in support of the forecasted expense levels for this account, stating that the "[h]istorical expense levels do not reflect the actual expenses that are now attributable to this account for the FTY and FPFTY."[7]

Q PLEASE DESCRIBE THE HISTORICAL EXPENSE LEVELS THAT YOU FOUND.

A In my Direct Testimony on Table GRM-3 (Valley), I showed that from 2010 through 2023, expense in this account ranged from a low of $1,855 (2013) to a high of $7,250 (2023).[8] In 2024, Valley suddenly began charging labor and overhead to this account.[9] This caused the expense level to balloon to $114,706, more than 1,400% growth. Valley expects that this will dip to $70,685 in the FPFTY 2026.

Q PLEASE ADDRESS MR. ROGERS' EXPLANATION OF WHY HISTORICAL EXPENSE DOESN'T REFLECT CURRENT OPERATIONS.

A Mr. Rogers first notes that Valley has started booking its Environmental Systems Research Institute, Inc. ("ESRI") software subscription and its Department of

[7] *See* the Rebuttal Testimony of Edward E. Rogers at page 10, lines 3-4.
[8] *See* the Direct Testimony of Greg R. Meyer at page 9, Table GRM-3 (Valley).
[9] *See* Exhibit_(ER-4R) attached to the Rebuttal Testimony of Edward E. Rogers.

Transportation training into a different account.[10] This would have the effect of reducing the overall expense, not provide justification for increasing it.

Mr. Rogers then states that Valley began charging expense related to training and evaluation into the account.[11] Of the $73,441 in non-direct labor charges to this account booked in 2024, this training platform represents a mere 7%, or $5,089. From there, Valley escalates the cost of this platform by 3% per year.

Mr. Rogers then notes that there is an additional Operational Qualification platform that will require additional labor and, thus, additional overhead.[12] It should be pointed out that my adjustment to Account 880 left the directly charged labor forecast alone because I addressed labor charges separately. What concerns me here is that the overheads that are being included represent a massive departure from the past and are greater than even the labor cost that Valley is projecting for this account.

Q ARE YOU IN ANY WAY ADJUSTING YOUR POSITION IN RESPONSE TO THE ADDITIONAL INFORMATION PROVIDED?

A Yes, slightly. Instead of limiting the non-direct labor cost to the 2023 expense level of $7,250, I am increasing my recommended expense to $8,582. This is to account for the new training software expense and the training supplies identified in Exhibit_(ER-4R). This represents a reduction of $34,121 to the non-direct labor portion of this account. As a reminder, I am not addressing the direct labor in this adjustment as it is handled in a separate adjustment.

[10] *See* the Rebuttal Testimony of Edward E. Rogers at page 10, lines 7-9.
[11] *Ibid*., lines 10-12.
[12] *Ibid*., lines 13-22.

INJURIES AND DAMAGES EXPENSES – ACCOUNT 925

Q HAVE YOU REVIEWED THE TESTIMONY OF VALLEY WITNESS JAMIE BEALE?

A Yes, Ms. Beale states that Valley is "comfortable accepting the reduction" that I proposed in my Direct Testimony.[13] This adjustment reduces Valley's Injuries and Damages expense by $30,981.

LABOR

Q HAVE YOU READ VALLEY'S REBUTTAL TESTIMONY ADDRESSING LABOR EXPENSES?

A Yes. I have read the Rebuttal Testimony of Valley's witness Edward E. Rogers discussing payroll increases.

Q WHAT LEVEL OF PAYROLL INCREASE IS VALLEY SEEKING IN THIS RATE CASE?

A Valley is proposing to increase Operation and Maintenance ("O&M") payroll expense by $113,582 from 2024 to 2026 FPFTY of approximately 10.0%.

[13] *See* the Rebuttal Testimony of Jamie Beale at page 3, lines 6-7.

Q HAVE YOU ANALYZED VALLEY'S WORKFORCE TO DETERMINE IF VALLEY'S WAGES ARE COMPETITIVE WITH THE MARKET?

A I have looked at two different workforce metrics. First, I looked at the employee levels at Valley since 2020. Second, I analyzed the historical average wage increases for Valley's employees.

Q PLEASE DESCRIBE THE LEVEL OF EMPLOYEES AT VALLEY SINCE 2020.

A I have prepared Table GRM-SR5 (Valley) below that shows the annual level of employees at Valley.

Table GRM-SR5 (Valley)

Employee Levels

Year	Employee Count
2020	31
2021	31
2022	31
2023	30
2024	31

Source:
2020 to 2024 from annual reports.

As the table above reveals, the number of employees on Valley's workforce is steady at 31 employees, except in 2023. The steady workforce numbers, as well as the ability to get back up to 31 employees, suggest that Valley does not have problems attracting employees to work for them.

Q WHAT FURTHER INFORMATION DO YOU HAVE ABOUT WAGE INCREASES GRANTED TO VALLEY'S EMPLOYEES OVER THE YEARS?

A I have compiled Table GRM-SR6 (Valley) below that shows the wage increase information that Valley includes in its annual reports to the Commission.

Table GRM-SR6 (Valley)

Wage Scale Changes

Year	Wage Change
2009	3.5% cost of living
2010	Rate increase effective December 1, 2010. Increase was in place for 1 month during 2010 year.
2011	4% wage adjustment
2012	3% wage adjustment
2013	3% wage adjustment
2014	3% wage adjustment
2015	3% wage adjustment
2016	3% wage adjustment
2017	3% wage adjustment
2018	3% wage adjustment
2019	3% wage adjustment
2020	3% wage adjustment
2021	3% wage adjustment
2022	4.5% wage adjustment
2023	6% wage adjustment
2024	4% wage adjustment

Source:

[1] 2009 to 2024 annual reports to the Pennsylvania Public Utility Commission

The table above reveals that since 2009 the predominant wage increase granted to Valley's employees has been 3%.

Q DO YOU CONTINUE TO SUPPORT THE 4% WAGE INCREASE YOU APPLIED TO THE VALLEY'S WAGES?

A Yes.

CONCLUSION

Q DOES THIS CONCLUDE YOUR SURREBUTTAL TESTIMONY?

A Yes, it does.

543168

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No. R-2025-3054393
	:	
Valley Energy, Inc.	:	
	:	

VERIFICATION

I, Greg R. Meyer, hereby state that the facts above set forth in my Surrebuttal Testimony, OCA Statement No. 1SR, are true and correct to the best of my knowledge, information, and belief and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa.C.S. § 4904 (relating to unsworn falsification to authorities).

DATED: August 28, 2025

Signature: */s/ Greg R. Meyer*
Greg R. Meyer

Address: Brubaker & Associates, Inc.
16690 Swingley Ridge Road
Suite 140
Chesterfield, MO 63017

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
v.	)	**R-2025-3054392**
Wellsboro Electric Company	)	

Surrebuttal Testimony of

Greg R. Meyer

OCA Statement 1SR

On behalf of

Pennsylvania Office of Consumer Advocate

Date Served: August 28, 2025

BRUBAKER & ASSOCIATES, INC.

Project 11858

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
v.	)	**R-2025-3054392**
Wellsboro Electric Company	)	

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BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
v.	)	**R-2025-3054392**
Wellsboro Electric Company	)	

Surrebuttal Testimony of Greg R. Meyer

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Greg R. Meyer. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q ARE YOU THE SAME GREG R. MEYER WHO PREVIOUSLY FILED DIRECT TESTIMONY ON JULY 15, 2025 AND REBUTTAL TESTIMONY ON AUGUST 13, 2025, IN THIS PROCEEDING?

A Yes, I am.

Q ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?

A I am appearing on behalf of the Pennsylvania Office of Consumer Advocate ("OCA").

Q PLEASE GIVE A BRIEF OVERVIEW OF YOUR SURREBUTTAL TESTIMONY.

A My Surrebuttal Testimony will address the following issues:

- I recommend the Pennsylvania Public Utility Commission ("Commission") not recognize a regulatory asset for the unrecovered rate case expense.
- I continue to support a revenue adjustment for Wellsboro Electric Company ("Wellsboro").
- I support a labor adjustment.
- I recommend the Commission adjust Accounts 920 and 932 expenses.
- I support an adjustment for sponsorships and lobbying.

My silence regarding any issue should not be construed as an endorsement of or acquiescence to positions advanced by Wellsboro.

RATE CASE EXPENSE REGULATORY ASSET

Q IS WELLSBORO CONTINUING TO REQUEST A REGULATORY ASSET FOR THE RECOVERY OF RATE CASE EXPENSE?

A Yes, and I am still opposed to granting recovery on the unamortized rate case expense balance. I am proposing, similar to the witnesses for the Bureau of Investigation and Enforcement and the Pennsylvania Office of Small Business Advocate, that rate case expense be normalized over a certain rate case interval. By normalizing rate case expense over a rate case interval there is no need to establish a regulatory asset.

Q WELLSBORO ARGUES THAT THE UNAMORTIZED BALANCE IS REQUIRED TO COMPENSATE WELLSBORO'S SHAREHOLDERS FOR PROVIDING FUNDS NECESSARY TO FILE A RATE CASE AND RECOVER THOSE EXPENSES OVER A MULTI-YEAR PERIOD.[1] PLEASE COMMENT.

A What Wellsboro fails to recognize is that there are benefits to Wellsboro's shareholders from filing a rate case. In filing a rate case, Wellsboro's shareholders are given an opportunity to have all of its operations reviewed and just and reasonable rates established to collect its cost of service. This review includes a detailed analysis of current market conditions to establish a reasonable rate of return. Given these benefits to Wellsboro's shareholders, it is entirely fair to normalize rate case expense and deny the establishment of a regulatory asset.

Q IN ITS REBUTTAL TESTIMONY, WELLSBORO ARGUES THAT THE UNAMORTIZED BALANCE OF RATE CASE EXPENSE IS SIMILAR TO THE INCLUSION OF MATERIALS AND SUPPLIES.[2] DO YOU AGREE?

A No. I do not think the arguments by Wellsboro trying to compare the ratemaking treatment of materials and supplies to the recovery of rate case expense is persuasive. Including materials and supplies in rate base recognizes that a utility should include a certain level of materials and supplies in its inventory to timely make repairs to the utility system to maintain reliable service. Given this expenditure of funds, it is necessary to provide a return on those inventory levels. That contrasts with the recovery

[1] *See* the Rebuttal Testimony of Howard Gorman at page 5, lines 10-13.
[2] *Ibid.,* lines 14-18.

of a recurring expense (not annually) for filing a rate case. Rate case expense recovery should be spread out over the rate case interval. This results in an even recovery of rate case expense from Wellsboro's ratepayers and assigns some of the benefits of rate case expenses to shareholders if they indeed prefunded those costs with shareholder funds.

RATE REVENUES

Q IS WELLSBORO STILL SUPPORTING A FIVE-YEAR AVERAGE USAGE PER CUSTOMER TO ANNUALIZE REVENUES?

A Yes. Wellsboro continues to argue that usage per customer has decreased and, therefore, the use of a five-year average usage methodology is appropriate. Wellsboro's witness Howard Gorman states the following:

> Second and of paramount importance, as shown in Table HSG-2 below, these classes have shown marked declines in annual kWh usage per customer in recent periods. In fact, the 2023 and 2024 numbers are well below the 5-year averages.[3]

Q DO YOU STILL SUPPORT A 10-YEAR AVERAGE USAGE PER CUSTOMER FOR THE COMMERCIAL AND INDUSTRIAL RATE CLASSES?

A Yes, I do. In the statement from Mr. Gorman that I quoted, he acknowledges that 2023 and 2024 were abnormal. So, two of the five years in his average are not normal. Therefore, I believe it is appropriate to look at usage per customer over a longer term to reduce the influence of these two abnormal years.

[3] *Ibid.,* at page 7, lines 17-19.

LABOR

Q HAVE YOU READ WELLSBORO'S REBUTTAL TESTIMONY ADDRESSING LABOR EXPENSES?

A Yes. I have read the Rebuttal Testimony of Wellsboro's witness Byron Farnsworth, Jr. discussing payroll increases.

Q WHAT LEVEL OF PAYROLL INCREASE IS WELLSBORO SEEKING IN THIS RATE CASE?

A Wellsboro is proposing to increase Operation and Maintenance ("O&M") payroll expense by $222,440 from 2024 to 2026 Fully Projected Future Test Year ("FPFTY"), or approximately 19.6%.

Q HAVE YOU ANALYZED WELLSBORO'S WORKFORCE TO DETERMINE IF WELLSBORO'S WAGES ARE COMPETITIVE WITH THE MARKET.

A I have looked at two different workforce metrics. First, I looked at the employee levels at Wellsboro since 2020. Second, I analyzed the employee tenure of Wellsboro's employees.

Q PLEASE DESCRIBE THE LEVEL OF EMPLOYEES AT WELLSBORO SINCE 2020.

A I have prepared Table GRM-SR1 (Wellsboro) that shows the annual level of employees at Wellsboro.

Table GRM-SR1 (Wellsboro)

Employee Levels

Year	Employee Count
2020	13
2021	16
2022	16
2023	17
2024	17
FTY	17
FPFTY	17

Source:
2020 to 2024 from annual reports;
TYs from OCA 7-12

As the table above reveals, the number of employees on Wellsboro's workforce is steady. The steady workforce numbers suggest that Wellsboro does not have problems attracting employees to work for them.

Q PLEASE DISCUSS WELLSBORO'S EMPLOYEE TENURE ANALYSIS.

A In Response to OCA Data Request 7-16, Wellsboro reported that the average Wellsboro's employee tenure was 11.6 years. This level of tenure is an important metric in that it indicates that Wellsboro's employees view positively their total compensation package to work for Wellsboro. Having an average tenure of 11.6 years does not indicate dissatisfaction with the wages paid to Wellsboro's employees. I have summarized this in Table GRM-SR2 (Wellsboro).

Table GRM-SR2 (Wellsboro)

Employee Tenure

Employee	Tenure
1	36
2	34
3	24
4	21
5	16
6	11
7	9
8	8
9	7
10	6
11	5
12	4
13	4
14	4
15	4
16	3
17	2
Average	11.6

Source:

Company Response to OCA Data Request 7-16.

Q DO YOU HAVE ANY FURTHER INFORMATION ABOUT WAGE INCREASES GRANTED TO WELLSBORO'S EMPLOYEES OVER THE YEARS?

A Yes, I have compiled Table GRM-SR3 (Wellsboro) that shows the wage increase information that Wellsboro provided to OCA Data Request 7-13.

Table GRM-SR3 (Wellsboro)

Average Wage Rate Increase

Year	Non-Union	Union
2020	3.00%	3.00%
2021	3.00%	3.00%
2022	4.50%	4.50%
2023	6.00%	6.50%
2024	4.00%	5.50%
2025	3.00%	4.00%
2026	3.00%	4.00%

Source:
Company Response to OCA Data Request 7-13.

The table reveals that since 2020 the average wage increase granted to Wellsboro's non-union employees has been 4.1% and 4.5% for union employees. One can also see that for 2025 and 2026, Wellsboro is projecting only 3% per year for non-union employees and 4% for its union workforce.

Q DO YOU CONTINUE TO SUPPORT THE 4% WAGE INCREASE YOU APPLIED TO WELLSBORO'S WAGES?

A Yes.

NON-LABOR CHARGES TO ADMINISTRATIVE AND GENERAL ("A&G") SALARIES – ACCOUNT 920

Q HAVE YOU REVIEWED THE REBUTTAL TESTIMONY OF JILL CAMPBELL RELATED TO YOUR ADJUSTMENT TO THE NON-LABOR PORTION OF A&G SALARIES – ACCOUNT 920?

A Yes, I have. Ms. Campbell notes that Wellsboro allocates more overhead than direct payroll and that this supports, in part, professional development for staff and management.[4] She does not provide a detailed breakdown and her answers are more general in nature, claiming that costs today will potentially provide benefits that customers will eventually see in rates later.[5] This does not provide adequate support for the increases that I noted in my Direct Testimony. I maintain that the benefits alleged are aspirational and may never materialize, while the costs have little to no real support. Therefore, I maintain that these costs should be excluded from revenue requirement.

NON-LABOR CHARGES TO MAINTENANCE OF GENERAL PROPERTY – ACCOUNT 932

Q HAVE YOU REVIEWED THE REBUTTAL TESTIMONY OF JILL CAMPBELL RELATED TO YOUR ADJUSTMENT TO THE NON-LABOR PORTION OF MAINTENANCE OF GENERAL PROPERTY – ACCOUNT 932?

A Yes, I have. In her testimony, she proffers the same general statements that were provided in Response to Data Request I&E-RE-20-D that I included in my Direct

[4] *See* the Rebuttal Testimony of Jill Campbell at page 5, lines 10-16.
[5] *Ibid.*, lines 18-21.

Testimony regarding changes to costs due to the completion of construction. She also mentions an error in Wellsboro's estimate of IT-related costs.[6] This error of $40,240 in the FPFTY represents over two thirds of the amount that I proposed to remove in my Direct Testimony ($59,983). As no study or bids have been provided to support Wellsboro's estimates, I am convinced that my position to remove $59,983 from expense for this account is appropriate.

SPONSORSHIPS AND LOBBYING

Q HAVE YOU REVIEWED THE REBUTTAL TESTIMONY OF BYRON FARNSWORTH, JR. AS IT RELATES TO SPONSORSHIPS (TERMED "ADVERTISING" IN HIS TESTIMONY)?

A Yes, I have. Mr. Farnsworth believes that these activities are important to include in the revenue requirement because:

- The expenses help Wellsboro's image – "reinforce the Company's strong presence in the community."[7]
- Helps fund non-utility events to "foster community spirit and engagement."[8]
- Add some level of energy efficiency awareness building.[9]
- The local community doesn't have a diverse support base from businesses and advertising supports this.[10]

[6] *Ibid.*, at page 6, lines 9-23.
[7] *See* the Rebuttal Testimony of Byron Farnsworth, Jr. at page 10, lines 10-11.
[8] *Ibid.*, lines 12-13.
[9] *Ibid.*, lines 13-15.
[10] *Ibid.*, lines 18-19.

Q DO YOU BELIEVE THESE ARGUMENTS SUPPORT INCLUDING THE COST OF SPONSORSHIPS AND LOBBYING IN REVENUE REQUIREMENT?

A No. Customers should not be forced to contribute to "the community" as directed by Wellsboro. Customers may feel that they are being captive contributors or that they have better ways to support their community than enhancing Wellsboro's image. If shareholders feel that the community would benefit from its support, then the shareholders can fund these efforts rather than foist the cost on to ratepayers.

Additionally, Wellsboro has failed to offer up any real analysis showing what amount of the advertising is directed at polishing its image versus what is directed at providing usable information regarding the services offered to customers. For these reasons, I continue to support my adjustment to remove sponsorships and lobbying expenses.

CONCLUSION

Q DOES THIS CONCLUDE YOUR SURREBUTTAL TESTIMONY?

A Yes, it does.

543169

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No. R-2025-3054392
	:	
Wellsboro Electric Company	:	

VERIFICATION

I, Greg R. Meyer, hereby state that the facts above set forth in my Surrebuttal Testimony, OCA Statement No. 1SR, are true and correct to the best of my knowledge, information, and belief and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa.C.S. § 4904 (relating to unsworn falsification to authorities).

DATED: August 28, 2025

Signature: */s/Greg R. Meyer*
Greg R. Meyer

Address: Brubaker Associates Inc.
16690 Swingley Ridge Road, Suite 140
Chesterfield, MO 63017

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
v.	)	**R-2025-3054394**
	)	**R-2025-3054393**
Citizens' Electric Company of Lewisburg, PA, Valley Energy, Inc., and Wellsboro Electric Company	)	**R-2025-3054392**

Surrebuttal Testimony of

Christopher C. Walters

OCA Statement 2SR

On behalf of

Pennsylvania Office of Consumer Advocate

Date Served: August 28, 2025

BRUBAKER & ASSOCIATES, INC.

Project 11858

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
v.	)	**R-2025-3054394**
	)	**R-2025-3054393**
Citizens' Electric Company of Lewisburg, PA, Valley Energy, Inc., and Wellsboro Electric Company	)	**R-2025-3054392**

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BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
v.	)	**R-2025-3054394**
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Citizens' Electric Company of Lewisburg, PA, Valley Energy, Inc., and Wellsboro Electric Company	)	**R-2025-3054392**

Surrebuttal Testimony of Christopher C. Walters

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Christopher C. Walters. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q ARE YOU THE SAME CHRISTOPHER C. WALTERS WHO PREVIOUSLY FILED DIRECT TESTIMONY ON JULY 15, 2025 AND REBUTTAL TESTIMONY ON AUGUST 13, 2025, IN THIS PROCEEDING?

A Yes, I am.

Q ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?

A I am appearing on behalf of the Pennsylvania Office of Consumer Advocate ("OCA").

Q PLEASE GIVE A BRIEF OVERVIEW OF YOUR SURREBUTTAL TESTIMONY.

A The purpose of my Surrebuttal Testimony in this proceeding is to respond to the Rebuttal testimony of Mr. D'Ascendis.

My silence on any particular issue should not be construed as tacit agreement or an endorsement of another party's position.

I. SUMMARY

Q PLEASE SUMMARIZE YOUR SURREBUTTAL TESTIMONY.

A In my Surrebuttal testimony, I respond to the criticisms of my analysis and testimony offered by Mr. D'Ascendis. I will demonstrate that Mr. D'Ascendis' criticisms are unfounded and lack merit. I reiterate my recommendation that the Companies be authorized a fair ROE of 9.50%, which is the midpoint of my recommended range of 9.0% to 10.0%.

II. RESPONSE TO CRITICISMS BY MR. D'ASCENDIS

A. Utility Credit Quality

Q MR. D'ASCENDIS ARGUES THAT UTILITIES HAVE NOT BEEN ABLE TO MAINTAIN CREDIT QUALITY DESPITE DECLINING AUTHORIZED ROES. WHAT EVIDENCE DOES HE OFFER IN SUPPORT OF THAT STATEMENT?

A Mr. D'Ascendis states that I often provide "the degradation of the credit quality of the utility industry over the recent period in a table in [my] direct testimony but does not in

this proceeding." He then asserts to reproduce a Table I provided in a recent testimony in an Ameren Illinois rate case, where we were both involved.

Q DID MR. D'ASCENDIS ACCURATELY REPRODUCE THAT TABLE?

A No, he did not. His Table 8 shows credit ratings of natural gas utility subsidiaries for two years: 2020 and 2025. His "replicated" table excludes 15 of the 17 years observed in my Ameren Illinois testimony which he cites. The full table from my Ameren Illinois testimony is provided below in Table CCW-1SR. As shown on this table, in 2009, approximately 75% of the industry was rated BBB+ or higher. Currently, 82% of the industry has a rating of BBB+ or higher. Mr. D'Ascendis opting to exclude more than 88% of the observations when claiming to have replicated my table is deceptive.

TABLE CCW-1SR

TABLE CCW-3

S&P Ratings by Category
Natural Gas Utility Subsidiaries
(Year End)

Description	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
A or higher	50%	50%	50%	50%	38%	33%	33%	44%	56%	33%	38%	38%	13%	15%	17%	14%	5%
A-	0%	0%	0%	0%	38%	33%	33%	22%	11%	11%	38%	38%	38%	38%	38%	35%	25%
BBB+	25%	25%	38%	38%	13%	22%	33%	33%	33%	44%	13%	13%	25%	30%	29%	38%	52%
BBB	13%	13%	0%	0%	0%	0%	0%	0%	0%	11%	13%	13%	25%	18%	16%	12%	17%
BBB-	13%	13%	13%	13%	13%	11%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	2%
Below BBB-	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	0%
Total	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%

Source: S&P CAPITAL IQ and Market Intelligence, data retrieved 12/31/2024.
Note: Subsidiary ratings used.

B. Use of Historical Authorized ROEs and the Risk Premium Method.

Q HOW DOES MR. D'ASCENDIS RESPOND TO YOUR USE OF HISTORICAL AUTHORIZED ROES IN YOUR ANALYSIS?

A He argues that my reliance on historical authorized returns is misplaced. According to him, those returns were set under different market and regulatory conditions, and therefore do not provide a reliable benchmark for determining the cost of equity today.

He emphasizes that the cost of equity must be forward-looking, reflecting current investor requirements rather than relying on past commission decisions. In his view, using historical averages risks understating today's return requirements.

Q DOES MR. D'ASCENDIS VIEW PAST AUTHORIZED ROES AS REPRESENTATIVE OF THE MARKET COST OF EQUITY?

A. No. He claims that past authorized returns were the product of regulatory compromises and policy considerations, not pure finance theory. Therefore, he argues that they should not be treated as direct evidence of investor-required returns.

Q IF HISTORICAL AUTHORIZED ROES ARE CONSIDERED, WHAT METHOD DOES MR. D'ASCENDIS ARGUE SHOULD BE APPLIED?

A He contends that the appropriate way to use that data is not by presenting simple averages, but by applying a linear Ordinary Least Squares ("OLS") regression model that measures the relationship between the equity risk premium ("ERP") (the difference between authorized ROEs and a corresponding interest rate) and interest rates. He believes this method better captures how regulators have adjusted returns in response to

changes in bond yields over time. He applies a similar methodology in response to my Risk Premium analysis. His OLS regression applied to my underlying data is presented in his Schedule DWD-11R.

Q WHAT ARE THE RESULTS OF HIS OLS REGRESSION ANALYSIS?

A For the Electric Risk Premium (Treasury Bond) analysis, his regression predicts a 5.94% ERP and a ROE of 10.50% assuming a projected 30-year Treasury yield of 4.56%. For the Gas Risk Premium (Treasury Bond) analysis, his regression predicts a 5.88% ERP and a ROE of 10.44%.

For the Electric Risk Premium (A rated Utility Bond) analysis, his regression predicts a 4.69% ERP and a ROE of 10.40% assuming a projected A-rated Utility bond yield of 5.71%. For the Gas Risk Premium (A rated Utility Bond) analysis, his regression predicts a 4.63% ERP and a ROE of 10.34%.

He notes that the R-squareds are both in excess of 82%, meaning that the movement in interest rates explains over 82% of the movement in the ERP, which he considers "to be a strong relationship."

Q DO YOU HAVE ANY GENERAL OBSERVATIONS ABOUT HIS "CORRECTION" TO YOUR RISK PREMIUM ANALYSIS YOU WOULD LIKE TO MAKE?

A Yes. Despite using prospective rates that are generally consistent with those realized in 2024 and 2025, Mr. D'Ascendis' "correction" to my Risk Premium analysis produces results so far removed from authorized returns over that same time period. For example,

his "corrected" version of my Electric Risk Premium over Treasury bonds assumes a prospective 30-year Treasury yield of 4.56%. The 2024 and 2025 average yield on 30-year Treasury bonds was 4.41% and 4.71%, respectively, meaning his prospective yield of 4.56% is squarely in the middle of those observations. During 2024 and year-to-date 2025, the average electric ROE was 9.78% and 9.72%, respectively. This means that the indicated ERP for 2024 and 2025 was 5.37% and 5.01%, respectively. Despite these most recent and relevant observations, Mr. D'Ascendis' "corrected" version of my Risk Premium analysis using OLS regression predicts an ERP of 5.94%, which is significantly higher than the ERP in 2024 or 2025. As a result of his disjointed analysis, his predicted ROE using the OLS regression method of 10.5% is also significantly in excess of the 9.78% and 9.72% average ROEs in 2024 and 2025.

Q DO YOU HAVE ANY CONCERNS WITH THE APPLICATION OF A SIMPLE OLS REGRESSION TO MEASURE THE RELATIONSHIP BETWEEN THE ERP AND INTEREST RATES?

A Yes, I do. The OLS regression model assigns equal weight to all observations over the study period, implicitly assuming that the relationship between the equity risk premium and bond yields has remained stable over that entire period. However, this approach may fail to capture structural changes in the regulatory landscape, investor expectations, and utility ratemaking practices that have occurred over time, particularly in more recent years. As a result, the model may give undue influence to outdated data and underrepresent the conditions currently driving authorized returns. If a regression

model is applied to capture the relationship between interest rates and the ERP, a Weighted Least Squares ("WLS") regression model is more appropriate.

Q WHAT IS WLS REGRESSION, AND WHY DO YOU BELIEVE IT IS MORE USEFUL THAN AN OLS REGRESSION?

A WLS regression is a variation of the traditional OLS regression method. Like OLS, it is used to estimate the relationship between variables such as the ERP and interest rates, but it improves on OLS by allowing certain observations to carry more influence than others based on their relevance or reliability.

OLS regression treats all data points equally, assigning the same weight to each observation regardless of when it occurred. This equal treatment can be problematic when analyzing long historical datasets, particularly when the relationship between variables (like bond yields and the ERP) has evolved over time due to changing market conditions or regulatory environments. For example, an ROE authorized by a state commission in 1988 may have been based on vastly different economic, policy, and risk considerations than one authorized in 2024 or 2025.

WLS regression addresses this by assigning greater weight to more recent data, which better reflects the current relationship between bond yields and the equity risk premium. In this analysis, I used an exponential weighting function that gradually reduces the influence of older data while emphasizing more recent observations. This approach helps ensure the regression model reflects contemporary market conditions more accurately, which is especially important for estimating the current cost of equity.

By using WLS, the goal is to produce a more relevant and timely estimate of the cost of equity for ratemaking purposes—one that better reflects today's utility environment rather than relying equally on data from decades ago that may no longer be representative.

Q WHAT ARE THE RESULTS OF A WLS REGRESSION ANALYSIS FOR THE ELECTRIC AND GAS RISK PREMIUM?

A The results of the WLS regression analysis for the electric and gas risk premium method are summarized below in Table CCW-2SR. I relied on the same data Mr. D'Ascendis used in his "correction" to my Risk Premium study. I also incorporated his prospective Treasury yield of 4.56% and his prospective A-rated utility bond yield of 5.71%. The results range from 9.80% to 9.86%. I will note that the R-squareds range from 0.9418 to 0.9530, all of which are higher than the R-squareds produced by Mr. D'Ascendis' simple OLS regression analysis which he concluded was a "strong relationship."

TABLE CCW-2SR

Bond Yield Plus Risk Premium
Weighted Least Squares Regression Summary Results

	Electric		Gas	
Description	Treasury	A-Rated Util.	Treasury	A-Rated Util.
Intercept (β0)	9.1053	8.8489	9.2518	9.0802
Slope (β1)	-0.8345	-0.8242	-0.8779	-0.8739
Proj. Yield[1]	4.56	5.71	4.56	5.71
Predicted ERP	5.30	4.14	5.25	4.09
ROE Estimate	9.86	9.85	9.81	9.80
R-Square	0.9418	0.9426	0.9530	0.9521

Source: Joint Statement No. 2R at 49.

C. DCF Model

Q PLEASE DESCRIBE MR. D'ASCENDIS' CONCERNS WITH YOUR DCF ANALYSIS.

A Mr. D'Ascendis expresses three concerns with my DCF model. Specifically, he:

- Disagrees with my reasoning to discount the results of my constant growth DCF model using analyst growth rates;
- My use of the sustainable growth rate method in the constant growth DCF model and;

- My use of a multi-stage DCF model.

Q PLEASE RESPOND TO MR. D'ASCENDIS' CONCERN REGARDING YOUR USE OF A PROJECTED GROSS DOMESTIC PRODUCT ("GDP") GROWTH RATE IN YOUR MULTI-STAGE DCF ANALYSIS.

A As a matter of principle, no company's earnings and/or dividends can grow faster than the economy in which it sells goods and services into perpetuity. In the long run, earnings growth will be limited by several factors, including, but not limited to, competition and market saturation. Mr. D'Ascendis' conclusion that GDP growth is not an upper limit for company and industry growth defies the economic and financial literature of which I am aware. In addition to the texts cited in my Direct Testimony[1] in support of the premise that GDP is a long-term cap on growth, I refer Mr. D'Ascendis to the following excerpts. First, as detailed in the Chartered Financial Analyst ("CFA") Institute's curriculum:

> For earnings growth to exceed GDP growth, the ratio of corporate profits to GDP must trend upward over time. It should be clear that the share of profits in GDP cannot rise forever. At some point, stagnant labor income would make workers unwilling to work and would also undermine demand, making further profit growth unsustainable. *Thus, in the long run, real earnings growth cannot exceed the growth rate of potential GDP.*[2] (emphasis added)

Additionally, Dr. Roger A. Morin details in his book, *New Regulatory Finance*, as follows:

[1]Corrected OCA Statement 2 at 39.

[2]CFA Program Curriculum, 2014 Level II Vol.1, "Ethical and Professional Standards, Quantitative Methods, and Economics" Reading 15 – Economic Growth and the Investment Decision, pages 608-609.

> It is useful to remember that eventually all company growth rates, especially utility services growth rates, converge to a level consistent with the growth rate of the aggregate economy.
>
> * * *
>
> […] it is quite possible that a company's dividends can grow faster than the general economy for five years*, but it is quite implausible for such growth to continue into perpetuity.*[3] (emphasis added)

Thus, my use of projected GDP growth as an upper limit for company or industry growth is wholly defensible, regardless of it not being a market measure. Mr. D'Ascendis has provided no substantive evidence to refute the findings of the academic and practitioner texts cited here and in my Direct Testimony on the matter. As such, Mr. D'Ascendis' concerns are unfounded and lack merit.

Q MR. D'ASCENDIS ARGUES THAT YOUR MULTI-STAGE DCF MODEL IS INAPPROPRIATE BECAUSE UTILITIES ARE IN THE STEADY-STATE GROWTH STAGE. HOW DO YOU RESPOND?

A I disagree with Mr. D'Ascendis' conclusion that utilities are in a steady-state growth stage. His characterization overlooks the unprecedented expansion of data centers and the corresponding surge in demand growth that utilities are currently experiencing. This development is not reflective of a mature, flat growth environment. Instead, it represents a significant structural change in the utility industry, with utilities investing heavily in infrastructure to meet rapidly rising load requirements. Given this environment, it is inappropriate to assume utilities are currently settled into steady-state growth. A multi-

[3]Roger A. Morin, New Regulatory Finance, pages 308-309.

stage DCF model is well-suited to capture this dynamic, recognizing higher near-term growth expectations before transitioning to long-run sustainable levels.

Q DID MR. D'ASCENDIS ALSO TAKE ISSUE WITH YOUR SUSTAINABLE GROWTH RATE DCF ANALYSIS?

A Yes, he did. Specifically, he takes issue with the assumption that future earnings growth is inversely related to the dividend payout ratio. He cites studies performed by Zhou and Ruland (2006) and Gwilym, *et al*. (2006), both of which cite the Arnott and Asness (2003) study, in support of his argument.[4]

Q PLEASE RESPOND.

A As an initial matter, no model is perfect, and at times can be more or less accurate than other models depending on various factors, such as economic conditions. As Mr. D'Ascendis states in his Direct Testimony, "[…] the use of multiple generally accepted common equity cost rate models also adds reliability and accuracy when arriving at a recommended common equity cost rate."[5] I agree using multiple methods provides a more comprehensive, and therefore, more reliable perspective on investors' return requirements. For this reason alone, it is important to perform a thorough analysis, and apply informed, reasoned judgement in the interpretation of the results. The use of multiple DCF models and considering those results is consistent with that approach.

[4]Citizens/Valley/Wellsboro Joint Statement No. 2R at 39-40.
[5]Citizens/Valley/Wellsboro Joint Statement No. 2 at 21.

In addition, using the retention growth methodology is a recognized reasonable method for estimating sustainable dividend growth and should not be ignored.

As noted by the CFA Institute's curriculum text:

> "We define the sustainable growth rate as the rate of dividend (and earnings) growth that can be sustained for a given level of return on equity, assuming that the capital structure is constant through time and that additional common stock is not issued. The reason for studying this concept is that it can help in estimating the stable growth rate in a Gordon growth model valuation, or the mature growth rate in a multistage DDM in which the Gordon growth formula is used to find the terminal value of the stock."

The expression to calculate the sustainable growth rate is:
$g = b$ x ROE[6]

Notably, the same CFA text observes that, in light of the Arnott and Asness (2003) study cited by Mr. D'Ascendis, "caution is appropriate in assuming that dividends displace earnings."[7] However, that same text concludes that "[n]evertheless, the equation can be useful as a simple expression for approximating the average rate at which dividends can grow over a long horizon."[8] Further, *Brigham and Houston* state that, "Companies that retain a high percentage of their earnings rather than paying them out as dividends generate more retained earnings and thus need less external capital."[9]

[6]*See* CFA Program Curriculum, 2014, Level II, Volume 4, "Dividend Discount Valuation," at page 264.

[7]*See* CFA Program Curriculum, 2014, Level II, Volume 4, "Dividend Discount Valuation," at pages 265-266.

[8]*Ibid.* at 266.

[9]*See Fundamentals of Financial Management*, Eugene F. Brigham and Joel F. Houston, Eleventh Edition 2007, Thomson South-Western, a Division of Thomson Corporation at page 558.

D. CAPM

Q PLEASE SUMMARIZE MR. D'ASCENDIS' CONCERNS WITH YOUR CAPM ANALYSIS.

A At page 51 of his Rebuttal Testimony, Mr. D'Ascendis expresses four general concerns with my CAPM analysis: (1) he argues I violated the Efficient Market Hypothesis ("EMH") by failing to include farthest out projected interest rates; (2) he disagrees with certain of my beta estimates; (3) he disagrees with my use of Kroll's recommended Market Risk Premium ("MRP"), and (4) he argues I should have included an Empirical CAPM analysis.

Q PLEASE RESPOND TO MR. D'ASCENDIS' ASSERTION THAT YOU VIOLATED THE EMH BY NOT INCORPORATING THE LONGEST AVAILABLE PROJECTED RISK-FREE RATE.

A Mr. D'Ascendis' assertion is misplaced and inconsistent with his own testimony. Under the semi-strong form of the EMH, which Mr. D'Ascendis is asserting, it is assumed securities prices reflect all publicly available information and past market data. Because Blue Chip is a paid subscription, not all investors necessarily have access to the data and therefore it would be hard to classify the projections offered by Blue Chip as public, a classification that is required under the semi-strong form of EMH.

Further, to the extent Mr. D'Ascendis failed to include all publicly available data, both historical and projected, he himself violated the EMH.

Q DO YOU HAVE ANY GENERAL COMMENTS IN RESPONSE TO MR. D'ASCENDIS WITH REGARD TO THE METHODS USED TO CALCULATE THE EXPECTED MARKET RETURN, AND ULTIMATELY, THE EXPECTED MRP.

A Yes. Regardless of the method used to calculate the expected market return, they all produce expected MRPs in the range of 5.50% to 8.00%. These estimates of the MRP are fully supported by financial texts and empirical research. For example, Dr. Morin notes several studies of the MRP in his book, *Modern Regulatory Finance*, have concluded that a MRP in the range of 5.0% to 8.0% is a reasonable estimate for the United States.[10] For example, the Duarte and Rosa study he cites, concludes that it is "quite difficult to improve upon when considering out-of-sample performance measures."[11] Dr. Morin also notes that a survey of professional practices showed that 71% of textbooks/tradebooks used a historical average as the MRP, and 60% of financial advisors used a MRP in the range of 7.0% to 7.4%, or a long-term arithmetic average.[12] My MRPs, regardless of the method used to calculate the expected market return component, is supported by substantial empirical evidence. Mr. D'Ascendis' concerns are unsupported and lack merit.

Q MR. D'ASCENDIS ARGUES THAT YOUR USE OF KROLL'S RECOMMENDED MRP OF 5.00% SHOULD BE REJECTED IN FAVOR OF OTHER MRP'S CITED IN KROLL. HOW DO YOU RESPOND.

[10]Dr. Morin references studies by Duarte & Rosa; Professors Ross, Westerfield, and Jordan; Mahera; and Brealey, Myers, and Allen. *See Modern Regulatory Finance,* Dr. Roger Morin, at 190-192.
[11]*See Modern Regulatory Finance,* Dr. Roger Morin, at 191, citing the Duarte and Rosa study.
[12]*See Modern Regulatory Finance,* Dr. Roger Morin, at 190, footnote 35.

A Mr. D'Ascendis states, erroneously, that I relied on an MRP of 5.00% as recommended by Kroll.[13] However, Kroll's recommended MRP that I relied on is actually 5.50%, not 5.00% as alleged by Mr. D'Ascendis. Kroll's recommended MRP is well within the range of well-known empirical data. For example, Dr. Morin notes in his book, *Modern Regulatory Finance*, that several studies of the MRP have concluded that a MRP in the range of 5.0% to 8.0% is a reasonable estimate for the United States.[14]

In addition, Mr. D'Ascendis seems to ignore the significant support from *Kroll* describing their recommended normalized, or conditional market risk premium. Specifically, Kroll's recommended risk premium is not explicitly based on any particular set of returns, but rather it is a conditional risk premium based on observations of relevant factors including, but not limited to fluctuations in global economic and financial market conditions. Kroll explains its equity risk premium methodology on its Cost of Capital Navigator site as follows:

> There is no single universally accepted methodology for estimating the ERP; consequently, there is wide diversity in practice among academics and financial advisors regarding ERP estimates. In estimating the conditional ERP, valuation analysts cannot simply use the long-term historical ERP, whether as reported or adjusted as we discussed above. A better alternative would be to examine approaches that are sensitive to the current economic conditions.
>
> Kroll employs a multi-faceted analysis to estimate the conditional ERP that takes into account a broad range of economic information and multiple ERP estimation methodologies to arrive at its recommendation.
>
> First, a reasonable range of normal or unconditional ERP is established.

[13]Joint Statement No. 2R at 53.

[14]Dr. Morin references studies by Duarte & Rosa; Professors Ross, Westerfield, and Jordan; Mahera; and Brealey, Myers, and Allen. See *Modern Regulatory Finance,* Dr. Roger A. Morin, at 190-192. Dr. Morin notes in his textbook that there is a "slight preference" for the upper end of the range (i.e., 8%) during tumultuous times in capital markets with examples being the 2008-2009 credit crisis and the 2020 pandemic.

> Second, based on current economic conditions, Kroll estimates where in the range the true ERP likely lies (top, bottom, or middle) by examining the current state of the economy (both by examining economic indicators and forecasts, as well as by analyzing the level and trends of stock market indices as forward indicators), in conjunction with the implied equity volatility and corporate spreads as indicators of perceived risk.

Mr. D'Ascendis' concern with the Kroll market risk premium is clearly misplaced. Kroll is one of the most often cited names in valuation and cost of capital matters, particularly regarding cost of capital testimony offered in regulated utility proceedings such as this one.

Q PLEASE RESPOND TO MR. D'ASCENDIS WITH REGARD TO YOUR USE OF VASICEK BETAS FROM S&P CAPITAL IQ.

A S&P Capital IQ is one of the most cited sources of financial data and other relevant utility industry information by rate of return witnesses in cost of capital testimony throughout the country. Further, S&P Capital IQ is one of the most recognized names in finance. Investors rely on data from S&P Capital IQ, particularly in the utility sector, to inform their investment making decisions.

Q IS THERE FINANCIAL LITERATURE DISCUSSING THE VASICEK METHOD OF ADJUSTING BETA IN COMPARISON TO THE BLUME METHOD EMPLOYED BY *VALUE LINE*?

A Yes. In an article titled "An Examination of Blume and Vasicek Betas" published in the journal *The Financial Review,* Martin Lally discusses the merits of both methods of adjusting beta. An observation made by Lally as it relates to the utility industry is as follows:

> A dramatic example of this is in U.S. electric utilities. A typical such firm has an estimated beta (unadjusted) of around 0.4 (Value Line, 1993). By virtue of being typical, the Vasicek estimate, with prior corresponding to this industry, will also be 0.4. By contrast, Blume adjusts the 0.4 to 0.6 [i.e. 0.33 + 0.67(0.4)]. The result is a dramatic overestimate by Blume, because a singularly relevant fact is ignored, i.e., membership of an industry whose average estimated, and therefore presumably also true, beta is well below one. Given that these firms have output prices that are set so as to recover costs, including the cost of equity, and they have substantial equity investment, then the implications of using Blume betas (i.e., not partitioning into industries) for measuring costs of equity are particularly severe.[15]

Mr. D'Ascendis' concerns with Vasicek-adjusted betas are unsupported and lack merit.

Q PLEASE RESPOND TO MR. D'ASCENDIS WITH REGARD TO YOU NOT PERFORMING AN ECAPM ANALYSIS.

A At page 57 of his Rebuttal Testimony, Mr. D'Ascendis simply states that my CAPM methodology is flawed because, among other reasons, I did not perform an ECAPM analysis. I explained in detail why I disagree with the use of an ECAPM, particularly with an adjusted beta, in my Direct Testimony at pages 74-77. Mr. D'Ascendis has offered nothing substantive to alter my opinion on the matter.

Q IS IT NECESSARY TO PERFORM AN ECAPM AT THIS TIME?

A No, as I explain in my Direct Testimony, the purpose of the adjustments presented in the ECAPM is to raise the intercept and flatten the security market line ("SML"). The applications of the "traditional" CAPM offered by the witnesses in this proceeding are

[15]The Financial Review, Vol. 33 (1998) at 183-198, "An Examination of Blume and Vasicek Betas," Martin Lally. (Emphasis Added).

anything but "traditional" given the extensive use of projected long-term yields and adjusted betas, both of which raise the intercept and flatten the SML.

For example, the use of a projected 30-year Treasury yield is a departure from the traditional CAPM in two regards. First, projected yields as those employed by myself in this proceeding are generally higher than spot yields which were used in the traditional form of the CAPM. Second, long-term yields, as employed by some witnesses in this proceeding, are generally higher than short-term yields, which were used in the traditional form of the CAPM. Each of these revised inputs accomplishes a key goal of the ECAPM by raising the intercept and flattening the slope of the SML.

Further, as I demonstrated in my Direct Testimony, the use of an adjusted beta as published by *Value Line* also raises the intercept and flattens the slope of the SML. As such, the application of the "traditional" CAPM in this proceeding has accomplished the goal of the ECAPM by implementing several inputs that raise the intercept and flatten the SML. Specifically, I am referring to forecasted long-term Treasury yields being used in favor of short-term spot yields and adjusted betas. Therefore, I maintain my position on the ECAPM.

E. D'Ascendis' Performance Factor Adjustment

Q MR. D'ASCENDIS CONTINUES TO RECOMMEND A FIVE-BASIS POINT UPWARD ADJUSTMENT TO THE ROE UNDER 66 PA.C.S. § 523 FOR "MANAGEMENT EFFICIENCY." DO YOU AGREE?

A No, I do not. While I am not an attorney or offering a legal opinion, it is my understanding that Section 523 does not mandate a performance adjustment to the return

on equity for management efficiency; it requires the Commission to consider the efficiency, effectiveness and adequacy of utility service when determining just and reasonable rates and provides the Commission with discretion to make adjustments to specific components of the utility's claimed cost of service as it determines to be proper and appropriate in determining just and reasonable rates. It is my understanding Section 523 does not provide an entitlement, and the Commission is under no obligation to award a premium for utilities simply meeting their statutory obligations.

Q HOW DOES THIS PERFORMANCE PREMIUM PROPOSAL SQUARE WITH THE STANDARDS IN HOPE AND BLUEFIELD?

A It does not. The standards set forth in Hope and Bluefield assume that a utility's authorized return is based on the presumption of sound, economic, and efficient management. That standard is built into the regulatory compact itself. Awarding a separate upward adjustment for "management efficiency" would double count what is already assumed and required by law.

Q WHAT IS THE RISK OF ADOPTING A PERFORMANCE FACTOR ADJUSTMENT AS MR. D'ASCENDIS PROPOSES?

A Such an adjustment risks creating an artificial premium that overcompensates shareholders for management behavior that is expected. Utilities are legally obligated to provide safe and adequate service at just and reasonable rates. Efficiency is not an optional standard deserving of an extra ROE; it is the baseline expectation under regulatory precedent.

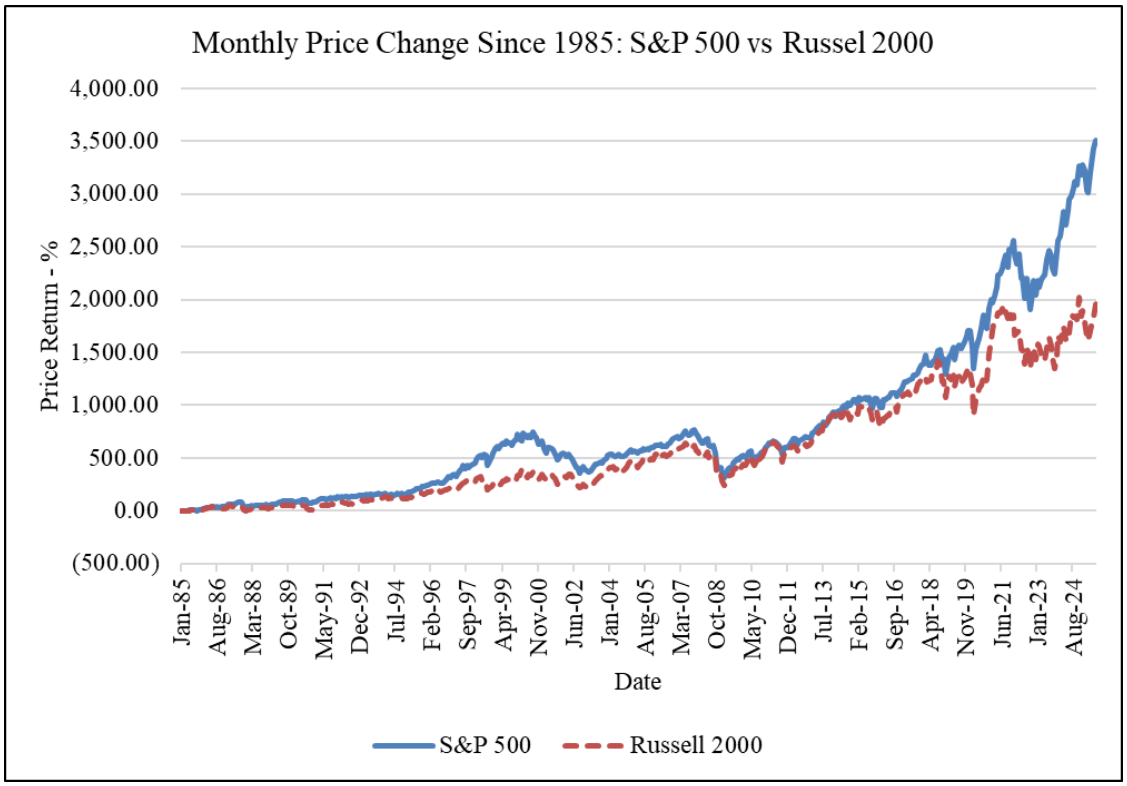
Q HOW SHOULD THE COMMISSION TREAT MR. D'ASCENDIS'S REQUEST?

A The Commission should reject it. Section 523 does not compel a performance factor adjustment and granting one would directly contradict Hope and Bluefield. The proper application of those precedents is to set a fair return that presumes efficient management, not to layer on an additional reward for simply meeting fundamental obligations.

F. D'Ascendis' Size Adjustment

Q MR. D'ASCENDIS TAKES ISSUE WITH YOUR FAILURE TO ADJUST YOUR RECOMMENDATION UPWARD TO ACCOUNT FOR SIZE. DOES HIS REBUTTAL TESTIMONY CHANGE YOUR POSITION ON THE MATTER?

A No. I continue to maintain my conclusion that a size adjustment is unnecessary. Trends in the returns of large capitalization stocks (i.e. the S&P 500) versus small capitalization stocks (i.e. the Russel 2000) show that small capitalization stock returns lag those produced by large capitalization stock returns. As shown in Figure CCW-1SR, the returns that used to be produced by investing in small capitalization stocks have disappeared in recent years, as the S&P 500 returns far exceed the returns compared to its small capitalization stock counterpart, the Russel 2000 index.



Finally, I&E Witnesses Keller and Patel (collectively the "I&E Witnesses"), and I all cite empirical evidence which concludes that, while size premiums are present in industrial companies, such a size premium is not present in utility companies, nor are they appropriate to include in valuing utilities. Mr. D'Ascendis cites an article by Dr. Thomas Zepp as a response to the evidence cited by the I&E Witnesses and me. Dr. Zepp's 2003 article is a narrow short communication that does not provide reliable support for applying a size adjustment in utility cost of equity determinations. While it critiques Wong's earlier work (the research article cited by the I&E witnesses and me), Dr. Zepp's analysis is incomplete, methodologically limited, and focused almost exclusively on a handful of small water utilities. This narrow evidence base is not sufficient to establish that a systematic size effect exists for utilities generally, let alone for electric or gas distribution companies.

Further, Dr. Zepp's recalculated betas are based on just three water companies, and his discounted cash flow study finds an average 99 basis point premium for small utilities that is only significant at the 90% confidence level. Typically, 95% is the standard confidence level used.

For these reasons, the size premium adjustment proposed by Mr. D'Ascendis is unsupported and lacks merit.

G. D'Ascendis' Updated Analysis

Q DID MR. D'ASCENDIS OFFER AN UPDATED COST OF EQUITY ANALYSIS IN HIS REBUTTAL?

A Yes, he did. The indicated range of ROEs attributable to Valley are from 10.42% to 10.89% (unadjusted) and from 11.47% to 11.94% (adjusted) and the indicated range of ROEs attributable to Citizens' and Wellsboro are from 10.19% to 10.76% 8 (unadjusted) and from 11.09% to 11.66% (adjusted). Each of the flaws that were present in Mr. D'Ascendis' analysis that I described in my direct testimony are present in his updated analysis. As such, Mr. D'Ascendis' updated analysis is still overstating the cost of equity for the Companies.

Q DOES THIS CONCLUDE YOUR SURREBUTTAL TESTIMONY?

A Yes, it does.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No. R-2025-3054394
	:	R-2025-3054393
Citizens' Electric Company of Lewisburg, PA, Valley Energy, Inc., and Wellsboro Electric Company	:	R-2025-3054392

VERIFICATION

I, Christopher C. Walters, hereby state that the facts above set forth in my Surrebuttal Testimony, OCA Statement No. 2SR, are true and correct to the best of my knowledge, information, and belief and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa.C.S. § 4904 (relating to unsworn falsification to authorities).

DATED: August 28, 2025

Signature: */s/ Christopher C. Walters*
Christopher C. Walters

Address: Brubaker & Associates, Inc.
16690 Swingley Ridge Road
Suite 140
Chesterfield, MO 63017

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
v.	)	**R-2025-3054394**
	)	**R-2025-3054393**
Citizens' Electric Company of Lewisburg, PA, Valley Energy, Inc., and Wellsboro Electric Company	)	**R-2025-3054392**

Surrebuttal Testimony of

Christopher C. Walters

OCA Statement 2SR

On behalf of

Pennsylvania Office of Consumer Advocate

Date Served: August 28, 2025

BRUBAKER & ASSOCIATES, INC.

Project 11858

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
v.	)	**R-2025-3054394**
	)	**R-2025-3054393**
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BEFORE THE
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Pennsylvania Public Utility Commission	)	
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Citizens' Electric Company of Lewisburg, PA, Valley Energy, Inc., and Wellsboro Electric Company	)	**R-2025-3054392**

Surrebuttal Testimony of Christopher C. Walters

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Christopher C. Walters. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q ARE YOU THE SAME CHRISTOPHER C. WALTERS WHO PREVIOUSLY FILED DIRECT TESTIMONY ON JULY 15, 2025 AND REBUTTAL TESTIMONY ON AUGUST 13, 2025, IN THIS PROCEEDING?

A Yes, I am.

Q ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?

A I am appearing on behalf of the Pennsylvania Office of Consumer Advocate ("OCA").

Q PLEASE GIVE A BRIEF OVERVIEW OF YOUR SURREBUTTAL TESTIMONY.

A The purpose of my Surrebuttal Testimony in this proceeding is to respond to the Rebuttal testimony of Mr. D'Ascendis.

My silence on any particular issue should not be construed as tacit agreement or an endorsement of another party's position.

I. SUMMARY

Q PLEASE SUMMARIZE YOUR SURREBUTTAL TESTIMONY.

A In my Surrebuttal testimony, I respond to the criticisms of my analysis and testimony offered by Mr. D'Ascendis. I will demonstrate that Mr. D'Ascendis' criticisms are unfounded and lack merit. I reiterate my recommendation that the Companies be authorized a fair ROE of 9.50%, which is the midpoint of my recommended range of 9.0% to 10.0%.

II. RESPONSE TO CRITICISMS BY MR. D'ASCENDIS

A. Utility Credit Quality

Q MR. D'ASCENDIS ARGUES THAT UTILITIES HAVE NOT BEEN ABLE TO MAINTAIN CREDIT QUALITY DESPITE DECLINING AUTHORIZED ROES. WHAT EVIDENCE DOES HE OFFER IN SUPPORT OF THAT STATEMENT?

A Mr. D'Ascendis states that I often provide "the degradation of the credit quality of the utility industry over the recent period in a table in [my] direct testimony but does not in

this proceeding." He then asserts to reproduce a Table I provided in a recent testimony in an Ameren Illinois rate case, where we were both involved.

Q DID MR. D'ASCENDIS ACCURATELY REPRODUCE THAT TABLE?

A No, he did not. His Table 8 shows credit ratings of natural gas utility subsidiaries for two years: 2020 and 2025. His "replicated" table excludes 15 of the 17 years observed in my Ameren Illinois testimony which he cites. The full table from my Ameren Illinois testimony is provided below in Table CCW-1SR. As shown on this table, in 2009, approximately 75% of the industry was rated BBB+ or higher. Currently, 82% of the industry has a rating of BBB+ or higher. Mr. D'Ascendis opting to exclude more than 88% of the observations when claiming to have replicated my table is deceptive.

TABLE CCW-1SR

TABLE CCW-3

S&P Ratings by Category
Natural Gas Utility Subsidiaries
(Year End)

Description	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
A or higher	50%	50%	50%	50%	38%	33%	33%	44%	56%	33%	38%	38%	13%	15%	17%	14%	5%
A-	0%	0%	0%	0%	38%	33%	33%	22%	11%	11%	38%	38%	38%	38%	38%	35%	25%
BBB+	25%	25%	38%	38%	13%	22%	33%	33%	33%	44%	13%	13%	25%	30%	29%	38%	52%
BBB	13%	13%	0%	0%	0%	0%	0%	0%	0%	11%	13%	13%	25%	18%	16%	12%	17%
BBB-	13%	13%	13%	13%	13%	11%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	2%
Below BBB-	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	0%
Total	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%

Source: S&P CAPITAL IQ and Market Intelligence, data retrieved 12/31/2024.
Note: Subsidiary ratings used.

B. Use of Historical Authorized ROEs and the Risk Premium Method.

Q HOW DOES MR. D'ASCENDIS RESPOND TO YOUR USE OF HISTORICAL AUTHORIZED ROES IN YOUR ANALYSIS?

A He argues that my reliance on historical authorized returns is misplaced. According to him, those returns were set under different market and regulatory conditions, and therefore do not provide a reliable benchmark for determining the cost of equity today.

He emphasizes that the cost of equity must be forward-looking, reflecting current investor requirements rather than relying on past commission decisions. In his view, using historical averages risks understating today's return requirements.

Q DOES MR. D'ASCENDIS VIEW PAST AUTHORIZED ROES AS REPRESENTATIVE OF THE MARKET COST OF EQUITY?

A. No. He claims that past authorized returns were the product of regulatory compromises and policy considerations, not pure finance theory. Therefore, he argues that they should not be treated as direct evidence of investor-required returns.

Q IF HISTORICAL AUTHORIZED ROES ARE CONSIDERED, WHAT METHOD DOES MR. D'ASCENDIS ARGUE SHOULD BE APPLIED?

A He contends that the appropriate way to use that data is not by presenting simple averages, but by applying a linear Ordinary Least Squares ("OLS") regression model that measures the relationship between the equity risk premium ("ERP") (the difference between authorized ROEs and a corresponding interest rate) and interest rates. He believes this method better captures how regulators have adjusted returns in response to

changes in bond yields over time. He applies a similar methodology in response to my Risk Premium analysis. His OLS regression applied to my underlying data is presented in his Schedule DWD-11R.

Q WHAT ARE THE RESULTS OF HIS OLS REGRESSION ANALYSIS?

A For the Electric Risk Premium (Treasury Bond) analysis, his regression predicts a 5.94% ERP and a ROE of 10.50% assuming a projected 30-year Treasury yield of 4.56%. For the Gas Risk Premium (Treasury Bond) analysis, his regression predicts a 5.88% ERP and a ROE of 10.44%.

For the Electric Risk Premium (A rated Utility Bond) analysis, his regression predicts a 4.69% ERP and a ROE of 10.40% assuming a projected A-rated Utility bond yield of 5.71%. For the Gas Risk Premium (A rated Utility Bond) analysis, his regression predicts a 4.63% ERP and a ROE of 10.34%.

He notes that the R-squareds are both in excess of 82%, meaning that the movement in interest rates explains over 82% of the movement in the ERP, which he considers "to be a strong relationship."

Q DO YOU HAVE ANY GENERAL OBSERVATIONS ABOUT HIS "CORRECTION" TO YOUR RISK PREMIUM ANALYSIS YOU WOULD LIKE TO MAKE?

A Yes. Despite using prospective rates that are generally consistent with those realized in 2024 and 2025, Mr. D'Ascendis' "correction" to my Risk Premium analysis produces results so far removed from authorized returns over that same time period. For example,

his "corrected" version of my Electric Risk Premium over Treasury bonds assumes a prospective 30-year Treasury yield of 4.56%. The 2024 and 2025 average yield on 30-year Treasury bonds was 4.41% and 4.71%, respectively, meaning his prospective yield of 4.56% is squarely in the middle of those observations. During 2024 and year-to-date 2025, the average electric ROE was 9.78% and 9.72%, respectively. This means that the indicated ERP for 2024 and 2025 was 5.37% and 5.01%, respectively. Despite these most recent and relevant observations, Mr. D'Ascendis' "corrected" version of my Risk Premium analysis using OLS regression predicts an ERP of 5.94%, which is significantly higher than the ERP in 2024 or 2025. As a result of his disjointed analysis, his predicted ROE using the OLS regression method of 10.5% is also significantly in excess of the 9.78% and 9.72% average ROEs in 2024 and 2025.

Q DO YOU HAVE ANY CONCERNS WITH THE APPLICATION OF A SIMPLE OLS REGRESSION TO MEASURE THE RELATIONSHIP BETWEEN THE ERP AND INTEREST RATES?

A Yes, I do. The OLS regression model assigns equal weight to all observations over the study period, implicitly assuming that the relationship between the equity risk premium and bond yields has remained stable over that entire period. However, this approach may fail to capture structural changes in the regulatory landscape, investor expectations, and utility ratemaking practices that have occurred over time, particularly in more recent years. As a result, the model may give undue influence to outdated data and underrepresent the conditions currently driving authorized returns. If a regression

model is applied to capture the relationship between interest rates and the ERP, a Weighted Least Squares ("WLS") regression model is more appropriate.

Q WHAT IS WLS REGRESSION, AND WHY DO YOU BELIEVE IT IS MORE USEFUL THAN AN OLS REGRESSION?

A WLS regression is a variation of the traditional OLS regression method. Like OLS, it is used to estimate the relationship between variables such as the ERP and interest rates, but it improves on OLS by allowing certain observations to carry more influence than others based on their relevance or reliability.

OLS regression treats all data points equally, assigning the same weight to each observation regardless of when it occurred. This equal treatment can be problematic when analyzing long historical datasets, particularly when the relationship between variables (like bond yields and the ERP) has evolved over time due to changing market conditions or regulatory environments. For example, an ROE authorized by a state commission in 1988 may have been based on vastly different economic, policy, and risk considerations than one authorized in 2024 or 2025.

WLS regression addresses this by assigning greater weight to more recent data, which better reflects the current relationship between bond yields and the equity risk premium. In this analysis, I used an exponential weighting function that gradually reduces the influence of older data while emphasizing more recent observations. This approach helps ensure the regression model reflects contemporary market conditions more accurately, which is especially important for estimating the current cost of equity.

By using WLS, the goal is to produce a more relevant and timely estimate of the cost of equity for ratemaking purposes—one that better reflects today's utility environment rather than relying equally on data from decades ago that may no longer be representative.

Q WHAT ARE THE RESULTS OF A WLS REGRESSION ANALYSIS FOR THE ELECTRIC AND GAS RISK PREMIUM?

A The results of the WLS regression analysis for the electric and gas risk premium method are summarized below in Table CCW-2SR. I relied on the same data Mr. D'Ascendis used in his "correction" to my Risk Premium study. I also incorporated his prospective Treasury yield of 4.56% and his prospective A-rated utility bond yield of 5.71%. The results range from 9.80% to 9.86%. I will note that the R-squareds range from 0.9418 to 0.9530, all of which are higher than the R-squareds produced by Mr. D'Ascendis' simple OLS regression analysis which he concluded was a "strong relationship."

TABLE CCW-2SR

Bond Yield Plus Risk Premium
Weighted Least Squares Regression Summary Results

	Electric		Gas	
Description	Treasury	A-Rated Util.	Treasury	A-Rated Util.
Intercept (β0)	9.1053	8.8489	9.2518	9.0802
Slope (β1)	-0.8345	-0.8242	-0.8779	-0.8739
Proj. Yield[1]	4.56	5.71	4.56	5.71
Predicted ERP	5.30	4.14	5.25	4.09
ROE Estimate	9.86	9.85	9.81	9.80
R-Square	0.9418	0.9426	0.9530	0.9521

Source: Joint Statement No. 2R at 49.

C. DCF Model

Q PLEASE DESCRIBE MR. D'ASCENDIS' CONCERNS WITH YOUR DCF ANALYSIS.

A Mr. D'Ascendis expresses three concerns with my DCF model. Specifically, he:

- Disagrees with my reasoning to discount the results of my constant growth DCF model using analyst growth rates;
- My use of the sustainable growth rate method in the constant growth DCF model and;

- My use of a multi-stage DCF model.

Q PLEASE RESPOND TO MR. D'ASCENDIS' CONCERN REGARDING YOUR USE OF A PROJECTED GROSS DOMESTIC PRODUCT ("GDP") GROWTH RATE IN YOUR MULTI-STAGE DCF ANALYSIS.

A As a matter of principle, no company's earnings and/or dividends can grow faster than the economy in which it sells goods and services into perpetuity. In the long run, earnings growth will be limited by several factors, including, but not limited to, competition and market saturation. Mr. D'Ascendis' conclusion that GDP growth is not an upper limit for company and industry growth defies the economic and financial literature of which I am aware. In addition to the texts cited in my Direct Testimony[1] in support of the premise that GDP is a long-term cap on growth, I refer Mr. D'Ascendis to the following excerpts. First, as detailed in the Chartered Financial Analyst ("CFA") Institute's curriculum:

> For earnings growth to exceed GDP growth, the ratio of corporate profits to GDP must trend upward over time. It should be clear that the share of profits in GDP cannot rise forever. At some point, stagnant labor income would make workers unwilling to work and would also undermine demand, making further profit growth unsustainable. *Thus, in the long run, real earnings growth cannot exceed the growth rate of potential GDP.*[2] (emphasis added)

Additionally, Dr. Roger A. Morin details in his book, *New Regulatory Finance*, as follows:

[1]Corrected OCA Statement 2 at 39.

[2]CFA Program Curriculum, 2014 Level II Vol.1, "Ethical and Professional Standards, Quantitative Methods, and Economics" Reading 15 – Economic Growth and the Investment Decision, pages 608-609.

> It is useful to remember that eventually all company growth rates, especially utility services growth rates, converge to a level consistent with the growth rate of the aggregate economy.
>
> * * *
>
> […] it is quite possible that a company's dividends can grow faster than the general economy for five years*, but it is quite implausible for such growth to continue into perpetuity.*[3] (emphasis added)

Thus, my use of projected GDP growth as an upper limit for company or industry growth is wholly defensible, regardless of it not being a market measure. Mr. D'Ascendis has provided no substantive evidence to refute the findings of the academic and practitioner texts cited here and in my Direct Testimony on the matter. As such, Mr. D'Ascendis' concerns are unfounded and lack merit.

Q MR. D'ASCENDIS ARGUES THAT YOUR MULTI-STAGE DCF MODEL IS INAPPROPRIATE BECAUSE UTILITIES ARE IN THE STEADY-STATE GROWTH STAGE. HOW DO YOU RESPOND?

A I disagree with Mr. D'Ascendis' conclusion that utilities are in a steady-state growth stage. His characterization overlooks the unprecedented expansion of data centers and the corresponding surge in demand growth that utilities are currently experiencing. This development is not reflective of a mature, flat growth environment. Instead, it represents a significant structural change in the utility industry, with utilities investing heavily in infrastructure to meet rapidly rising load requirements. Given this environment, it is inappropriate to assume utilities are currently settled into steady-state growth. A multi-

[3]Roger A. Morin, New Regulatory Finance, pages 308-309.

stage DCF model is well-suited to capture this dynamic, recognizing higher near-term growth expectations before transitioning to long-run sustainable levels.

Q DID MR. D'ASCENDIS ALSO TAKE ISSUE WITH YOUR SUSTAINABLE GROWTH RATE DCF ANALYSIS?

A Yes, he did. Specifically, he takes issue with the assumption that future earnings growth is inversely related to the dividend payout ratio. He cites studies performed by Zhou and Ruland (2006) and Gwilym, *et al*. (2006), both of which cite the Arnott and Asness (2003) study, in support of his argument.[4]

Q PLEASE RESPOND.

A As an initial matter, no model is perfect, and at times can be more or less accurate than other models depending on various factors, such as economic conditions. As Mr. D'Ascendis states in his Direct Testimony, "[…] the use of multiple generally accepted common equity cost rate models also adds reliability and accuracy when arriving at a recommended common equity cost rate."[5] I agree using multiple methods provides a more comprehensive, and therefore, more reliable perspective on investors' return requirements. For this reason alone, it is important to perform a thorough analysis, and apply informed, reasoned judgement in the interpretation of the results. The use of multiple DCF models and considering those results is consistent with that approach.

[4]Citizens/Valley/Wellsboro Joint Statement No. 2R at 39-40.
[5]Citizens/Valley/Wellsboro Joint Statement No. 2 at 21.

In addition, using the retention growth methodology is a recognized reasonable method for estimating sustainable dividend growth and should not be ignored.

As noted by the CFA Institute's curriculum text:

> "We define the sustainable growth rate as the rate of dividend (and earnings) growth that can be sustained for a given level of return on equity, assuming that the capital structure is constant through time and that additional common stock is not issued. The reason for studying this concept is that it can help in estimating the stable growth rate in a Gordon growth model valuation, or the mature growth rate in a multistage DDM in which the Gordon growth formula is used to find the terminal value of the stock."

The expression to calculate the sustainable growth rate is:
$g = b$ x ROE[6]

Notably, the same CFA text observes that, in light of the Arnott and Asness (2003) study cited by Mr. D'Ascendis, "caution is appropriate in assuming that dividends displace earnings."[7] However, that same text concludes that "[n]evertheless, the equation can be useful as a simple expression for approximating the average rate at which dividends can grow over a long horizon."[8] Further, *Brigham and Houston* state that, "Companies that retain a high percentage of their earnings rather than paying them out as dividends generate more retained earnings and thus need less external capital."[9]

[6]*See* CFA Program Curriculum, 2014, Level II, Volume 4, "Dividend Discount Valuation," at page 264.

[7]*See* CFA Program Curriculum, 2014, Level II, Volume 4, "Dividend Discount Valuation," at pages 265-266.

[8]*Ibid.* at 266.

[9]*See Fundamentals of Financial Management*, Eugene F. Brigham and Joel F. Houston, Eleventh Edition 2007, Thomson South-Western, a Division of Thomson Corporation at page 558.

D. CAPM

Q PLEASE SUMMARIZE MR. D'ASCENDIS' CONCERNS WITH YOUR CAPM ANALYSIS.

A At page 51 of his Rebuttal Testimony, Mr. D'Ascendis expresses four general concerns with my CAPM analysis: (1) he argues I violated the Efficient Market Hypothesis ("EMH") by failing to include farthest out projected interest rates; (2) he disagrees with certain of my beta estimates; (3) he disagrees with my use of Kroll's recommended Market Risk Premium ("MRP"), and (4) he argues I should have included an Empirical CAPM analysis.

Q PLEASE RESPOND TO MR. D'ASCENDIS' ASSERTION THAT YOU VIOLATED THE EMH BY NOT INCORPORATING THE LONGEST AVAILABLE PROJECTED RISK-FREE RATE.

A Mr. D'Ascendis' assertion is misplaced and inconsistent with his own testimony. Under the semi-strong form of the EMH, which Mr. D'Ascendis is asserting, it is assumed securities prices reflect all publicly available information and past market data. Because Blue Chip is a paid subscription, not all investors necessarily have access to the data and therefore it would be hard to classify the projections offered by Blue Chip as public, a classification that is required under the semi-strong form of EMH.

Further, to the extent Mr. D'Ascendis failed to include all publicly available data, both historical and projected, he himself violated the EMH.

Q DO YOU HAVE ANY GENERAL COMMENTS IN RESPONSE TO MR. D'ASCENDIS WITH REGARD TO THE METHODS USED TO CALCULATE THE EXPECTED MARKET RETURN, AND ULTIMATELY, THE EXPECTED MRP.

A Yes. Regardless of the method used to calculate the expected market return, they all produce expected MRPs in the range of 5.50% to 8.00%. These estimates of the MRP are fully supported by financial texts and empirical research. For example, Dr. Morin notes several studies of the MRP in his book, *Modern Regulatory Finance*, have concluded that a MRP in the range of 5.0% to 8.0% is a reasonable estimate for the United States.[10] For example, the Duarte and Rosa study he cites, concludes that it is "quite difficult to improve upon when considering out-of-sample performance measures."[11] Dr. Morin also notes that a survey of professional practices showed that 71% of textbooks/tradebooks used a historical average as the MRP, and 60% of financial advisors used a MRP in the range of 7.0% to 7.4%, or a long-term arithmetic average.[12] My MRPs, regardless of the method used to calculate the expected market return component, is supported by substantial empirical evidence. Mr. D'Ascendis' concerns are unsupported and lack merit.

Q MR. D'ASCENDIS ARGUES THAT YOUR USE OF KROLL'S RECOMMENDED MRP OF 5.00% SHOULD BE REJECTED IN FAVOR OF OTHER MRP'S CITED IN KROLL. HOW DO YOU RESPOND.

[10]Dr. Morin references studies by Duarte & Rosa; Professors Ross, Westerfield, and Jordan; Mahera; and Brealey, Myers, and Allen. *See Modern Regulatory Finance,* Dr. Roger Morin, at 190-192.
[11]*See Modern Regulatory Finance,* Dr. Roger Morin, at 191, citing the Duarte and Rosa study.
[12]*See Modern Regulatory Finance,* Dr. Roger Morin, at 190, footnote 35.

A Mr. D'Ascendis states, erroneously, that I relied on an MRP of 5.00% as recommended by Kroll.[13] However, Kroll's recommended MRP that I relied on is actually 5.50%, not 5.00% as alleged by Mr. D'Ascendis. Kroll's recommended MRP is well within the range of well-known empirical data. For example, Dr. Morin notes in his book, *Modern Regulatory Finance*, that several studies of the MRP have concluded that a MRP in the range of 5.0% to 8.0% is a reasonable estimate for the United States.[14]

In addition, Mr. D'Ascendis seems to ignore the significant support from *Kroll* describing their recommended normalized, or conditional market risk premium. Specifically, Kroll's recommended risk premium is not explicitly based on any particular set of returns, but rather it is a conditional risk premium based on observations of relevant factors including, but not limited to fluctuations in global economic and financial market conditions. Kroll explains its equity risk premium methodology on its Cost of Capital Navigator site as follows:

> There is no single universally accepted methodology for estimating the ERP; consequently, there is wide diversity in practice among academics and financial advisors regarding ERP estimates. In estimating the conditional ERP, valuation analysts cannot simply use the long-term historical ERP, whether as reported or adjusted as we discussed above. A better alternative would be to examine approaches that are sensitive to the current economic conditions.
>
> Kroll employs a multi-faceted analysis to estimate the conditional ERP that takes into account a broad range of economic information and multiple ERP estimation methodologies to arrive at its recommendation.
>
> First, a reasonable range of normal or unconditional ERP is established.

[13]Joint Statement No. 2R at 53.

[14]Dr. Morin references studies by Duarte & Rosa; Professors Ross, Westerfield, and Jordan; Mahera; and Brealey, Myers, and Allen. See *Modern Regulatory Finance,* Dr. Roger A. Morin, at 190-192. Dr. Morin notes in his textbook that there is a "slight preference" for the upper end of the range (i.e., 8%) during tumultuous times in capital markets with examples being the 2008-2009 credit crisis and the 2020 pandemic.

> Second, based on current economic conditions, Kroll estimates where in the range the true ERP likely lies (top, bottom, or middle) by examining the current state of the economy (both by examining economic indicators and forecasts, as well as by analyzing the level and trends of stock market indices as forward indicators), in conjunction with the implied equity volatility and corporate spreads as indicators of perceived risk.

Mr. D'Ascendis' concern with the Kroll market risk premium is clearly misplaced. Kroll is one of the most often cited names in valuation and cost of capital matters, particularly regarding cost of capital testimony offered in regulated utility proceedings such as this one.

Q PLEASE RESPOND TO MR. D'ASCENDIS WITH REGARD TO YOUR USE OF VASICEK BETAS FROM S&P CAPITAL IQ.

A S&P Capital IQ is one of the most cited sources of financial data and other relevant utility industry information by rate of return witnesses in cost of capital testimony throughout the country. Further, S&P Capital IQ is one of the most recognized names in finance. Investors rely on data from S&P Capital IQ, particularly in the utility sector, to inform their investment making decisions.

Q IS THERE FINANCIAL LITERATURE DISCUSSING THE VASICEK METHOD OF ADJUSTING BETA IN COMPARISON TO THE BLUME METHOD EMPLOYED BY *VALUE LINE*?

A Yes. In an article titled "An Examination of Blume and Vasicek Betas" published in the journal *The Financial Review,* Martin Lally discusses the merits of both methods of adjusting beta. An observation made by Lally as it relates to the utility industry is as follows:

> A dramatic example of this is in U.S. electric utilities. A typical such firm has an estimated beta (unadjusted) of around 0.4 (Value Line, 1993). By virtue of being typical, the Vasicek estimate, with prior corresponding to this industry, will also be 0.4. By contrast, Blume adjusts the 0.4 to 0.6 [i.e. 0.33 + 0.67(0.4)]. The result is a dramatic overestimate by Blume, because a singularly relevant fact is ignored, i.e., membership of an industry whose average estimated, and therefore presumably also true, beta is well below one. Given that these firms have output prices that are set so as to recover costs, including the cost of equity, and they have substantial equity investment, then the implications of using Blume betas (i.e., not partitioning into industries) for measuring costs of equity are particularly severe.[15]

Mr. D'Ascendis' concerns with Vasicek-adjusted betas are unsupported and lack merit.

Q PLEASE RESPOND TO MR. D'ASCENDIS WITH REGARD TO YOU NOT PERFORMING AN ECAPM ANALYSIS.

A At page 57 of his Rebuttal Testimony, Mr. D'Ascendis simply states that my CAPM methodology is flawed because, among other reasons, I did not perform an ECAPM analysis. I explained in detail why I disagree with the use of an ECAPM, particularly with an adjusted beta, in my Direct Testimony at pages 74-77. Mr. D'Ascendis has offered nothing substantive to alter my opinion on the matter.

Q IS IT NECESSARY TO PERFORM AN ECAPM AT THIS TIME?

A No, as I explain in my Direct Testimony, the purpose of the adjustments presented in the ECAPM is to raise the intercept and flatten the security market line ("SML"). The applications of the "traditional" CAPM offered by the witnesses in this proceeding are

[15]The Financial Review, Vol. 33 (1998) at 183-198, "An Examination of Blume and Vasicek Betas," Martin Lally. (Emphasis Added).

anything but "traditional" given the extensive use of projected long-term yields and adjusted betas, both of which raise the intercept and flatten the SML.

For example, the use of a projected 30-year Treasury yield is a departure from the traditional CAPM in two regards. First, projected yields as those employed by myself in this proceeding are generally higher than spot yields which were used in the traditional form of the CAPM. Second, long-term yields, as employed by some witnesses in this proceeding, are generally higher than short-term yields, which were used in the traditional form of the CAPM. Each of these revised inputs accomplishes a key goal of the ECAPM by raising the intercept and flattening the slope of the SML.

Further, as I demonstrated in my Direct Testimony, the use of an adjusted beta as published by *Value Line* also raises the intercept and flattens the slope of the SML. As such, the application of the "traditional" CAPM in this proceeding has accomplished the goal of the ECAPM by implementing several inputs that raise the intercept and flatten the SML. Specifically, I am referring to forecasted long-term Treasury yields being used in favor of short-term spot yields and adjusted betas. Therefore, I maintain my position on the ECAPM.

E. D'Ascendis' Performance Factor Adjustment

Q MR. D'ASCENDIS CONTINUES TO RECOMMEND A FIVE-BASIS POINT UPWARD ADJUSTMENT TO THE ROE UNDER 66 PA.C.S. § 523 FOR "MANAGEMENT EFFICIENCY." DO YOU AGREE?

A No, I do not. While I am not an attorney or offering a legal opinion, it is my understanding that Section 523 does not mandate a performance adjustment to the return

on equity for management efficiency; it requires the Commission to consider the efficiency, effectiveness and adequacy of utility service when determining just and reasonable rates and provides the Commission with discretion to make adjustments to specific components of the utility's claimed cost of service as it determines to be proper and appropriate in determining just and reasonable rates. It is my understanding Section 523 does not provide an entitlement, and the Commission is under no obligation to award a premium for utilities simply meeting their statutory obligations.

Q HOW DOES THIS PERFORMANCE PREMIUM PROPOSAL SQUARE WITH THE STANDARDS IN HOPE AND BLUEFIELD?

A It does not. The standards set forth in Hope and Bluefield assume that a utility's authorized return is based on the presumption of sound, economic, and efficient management. That standard is built into the regulatory compact itself. Awarding a separate upward adjustment for "management efficiency" would double count what is already assumed and required by law.

Q WHAT IS THE RISK OF ADOPTING A PERFORMANCE FACTOR ADJUSTMENT AS MR. D'ASCENDIS PROPOSES?

A Such an adjustment risks creating an artificial premium that overcompensates shareholders for management behavior that is expected. Utilities are legally obligated to provide safe and adequate service at just and reasonable rates. Efficiency is not an optional standard deserving of an extra ROE; it is the baseline expectation under regulatory precedent.

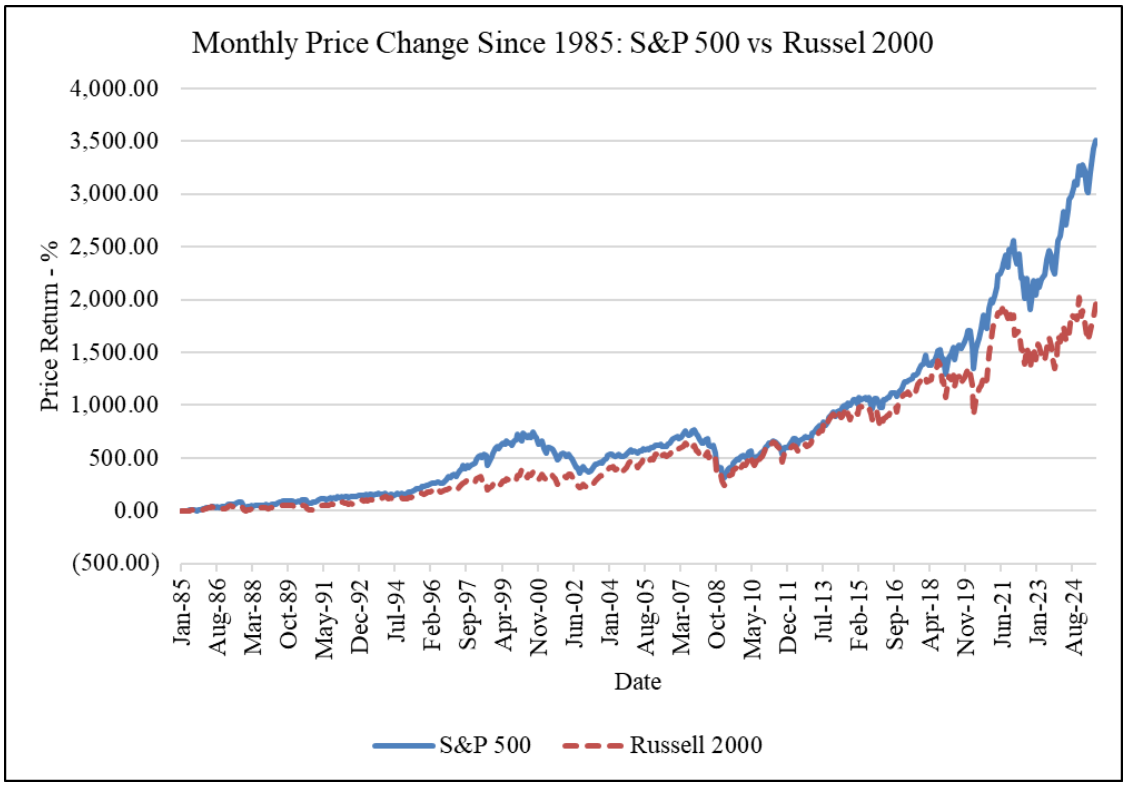
Q HOW SHOULD THE COMMISSION TREAT MR. D'ASCENDIS'S REQUEST?

A The Commission should reject it. Section 523 does not compel a performance factor adjustment and granting one would directly contradict Hope and Bluefield. The proper application of those precedents is to set a fair return that presumes efficient management, not to layer on an additional reward for simply meeting fundamental obligations.

F. D'Ascendis' Size Adjustment

Q MR. D'ASCENDIS TAKES ISSUE WITH YOUR FAILURE TO ADJUST YOUR RECOMMENDATION UPWARD TO ACCOUNT FOR SIZE. DOES HIS REBUTTAL TESTIMONY CHANGE YOUR POSITION ON THE MATTER?

A No. I continue to maintain my conclusion that a size adjustment is unnecessary. Trends in the returns of large capitalization stocks (i.e. the S&P 500) versus small capitalization stocks (i.e. the Russel 2000) show that small capitalization stock returns lag those produced by large capitalization stock returns. As shown in Figure CCW-1SR, the returns that used to be produced by investing in small capitalization stocks have disappeared in recent years, as the S&P 500 returns far exceed the returns compared to its small capitalization stock counterpart, the Russel 2000 index.



Finally, I&E Witnesses Keller and Patel (collectively the "I&E Witnesses"), and I all cite empirical evidence which concludes that, while size premiums are present in industrial companies, such a size premium is not present in utility companies, nor are they appropriate to include in valuing utilities. Mr. D'Ascendis cites an article by Dr. Thomas Zepp as a response to the evidence cited by the I&E Witnesses and me. Dr. Zepp's 2003 article is a narrow short communication that does not provide reliable support for applying a size adjustment in utility cost of equity determinations. While it critiques Wong's earlier work (the research article cited by the I&E witnesses and me), Dr. Zepp's analysis is incomplete, methodologically limited, and focused almost exclusively on a handful of small water utilities. This narrow evidence base is not sufficient to establish that a systematic size effect exists for utilities generally, let alone for electric or gas distribution companies.

Further, Dr. Zepp's recalculated betas are based on just three water companies, and his discounted cash flow study finds an average 99 basis point premium for small utilities that is only significant at the 90% confidence level. Typically, 95% is the standard confidence level used.

For these reasons, the size premium adjustment proposed by Mr. D'Ascendis is unsupported and lacks merit.

G. D'Ascendis' Updated Analysis

Q DID MR. D'ASCENDIS OFFER AN UPDATED COST OF EQUITY ANALYSIS IN HIS REBUTTAL?

A Yes, he did. The indicated range of ROEs attributable to Valley are from 10.42% to 10.89% (unadjusted) and from 11.47% to 11.94% (adjusted) and the indicated range of ROEs attributable to Citizens' and Wellsboro are from 10.19% to 10.76% 8 (unadjusted) and from 11.09% to 11.66% (adjusted). Each of the flaws that were present in Mr. D'Ascendis' analysis that I described in my direct testimony are present in his updated analysis. As such, Mr. D'Ascendis' updated analysis is still overstating the cost of equity for the Companies.

Q DOES THIS CONCLUDE YOUR SURREBUTTAL TESTIMONY?

A Yes, it does.

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BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No. R-2025-3054394
	:	R-2025-3054393
Citizens' Electric Company of Lewisburg, PA, Valley Energy, Inc., and Wellsboro Electric Company	:	R-2025-3054392

VERIFICATION

I, Christopher C. Walters, hereby state that the facts above set forth in my Surrebuttal Testimony, OCA Statement No. 2SR, are true and correct to the best of my knowledge, information, and belief and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa.C.S. § 4904 (relating to unsworn falsification to authorities).

DATED: August 28, 2025

Signature: */s/ Christopher C. Walters*
Christopher C. Walters

Address: Brubaker & Associates, Inc.
16690 Swingley Ridge Road
Suite 140
Chesterfield, MO 63017

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
v.	)	**R-2025-3054394**
	)	**R-2025-3054393**
Citizens' Electric Company of Lewisburg, PA, Valley Energy, Inc., and Wellsboro Electric Company	)	**R-2025-3054392**

Surrebuttal Testimony of

Christopher C. Walters

OCA Statement 2SR

On behalf of

Pennsylvania Office of Consumer Advocate

Date Served: August 28, 2025

BRUBAKER & ASSOCIATES, INC.

Project 11858

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
v.	)	**R-2025-3054394**
	)	**R-2025-3054393**
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BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
v.	)	**R-2025-3054394**
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Citizens' Electric Company of Lewisburg, PA, Valley Energy, Inc., and Wellsboro Electric Company	)	**R-2025-3054392**

Surrebuttal Testimony of Christopher C. Walters

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Christopher C. Walters. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q ARE YOU THE SAME CHRISTOPHER C. WALTERS WHO PREVIOUSLY FILED DIRECT TESTIMONY ON JULY 15, 2025 AND REBUTTAL TESTIMONY ON AUGUST 13, 2025, IN THIS PROCEEDING?

A Yes, I am.

Q ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?

A I am appearing on behalf of the Pennsylvania Office of Consumer Advocate ("OCA").

Q PLEASE GIVE A BRIEF OVERVIEW OF YOUR SURREBUTTAL TESTIMONY.

A The purpose of my Surrebuttal Testimony in this proceeding is to respond to the Rebuttal testimony of Mr. D'Ascendis.

My silence on any particular issue should not be construed as tacit agreement or an endorsement of another party's position.

I. SUMMARY

Q PLEASE SUMMARIZE YOUR SURREBUTTAL TESTIMONY.

A In my Surrebuttal testimony, I respond to the criticisms of my analysis and testimony offered by Mr. D'Ascendis. I will demonstrate that Mr. D'Ascendis' criticisms are unfounded and lack merit. I reiterate my recommendation that the Companies be authorized a fair ROE of 9.50%, which is the midpoint of my recommended range of 9.0% to 10.0%.

II. RESPONSE TO CRITICISMS BY MR. D'ASCENDIS

A. Utility Credit Quality

Q MR. D'ASCENDIS ARGUES THAT UTILITIES HAVE NOT BEEN ABLE TO MAINTAIN CREDIT QUALITY DESPITE DECLINING AUTHORIZED ROES. WHAT EVIDENCE DOES HE OFFER IN SUPPORT OF THAT STATEMENT?

A Mr. D'Ascendis states that I often provide "the degradation of the credit quality of the utility industry over the recent period in a table in [my] direct testimony but does not in

this proceeding." He then asserts to reproduce a Table I provided in a recent testimony in an Ameren Illinois rate case, where we were both involved.

Q DID MR. D'ASCENDIS ACCURATELY REPRODUCE THAT TABLE?

A No, he did not. His Table 8 shows credit ratings of natural gas utility subsidiaries for two years: 2020 and 2025. His "replicated" table excludes 15 of the 17 years observed in my Ameren Illinois testimony which he cites. The full table from my Ameren Illinois testimony is provided below in Table CCW-1SR. As shown on this table, in 2009, approximately 75% of the industry was rated BBB+ or higher. Currently, 82% of the industry has a rating of BBB+ or higher. Mr. D'Ascendis opting to exclude more than 88% of the observations when claiming to have replicated my table is deceptive.

TABLE CCW-1SR

TABLE CCW-3

S&P Ratings by Category
Natural Gas Utility Subsidiaries
(Year End)

Description	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
A or higher	50%	50%	50%	50%	38%	33%	33%	44%	56%	33%	38%	38%	13%	15%	17%	14%	5%
A-	0%	0%	0%	0%	38%	33%	33%	22%	11%	11%	38%	38%	38%	38%	38%	35%	25%
BBB+	25%	25%	38%	38%	13%	22%	33%	33%	33%	44%	13%	13%	25%	30%	29%	38%	52%
BBB	13%	13%	0%	0%	0%	0%	0%	0%	0%	11%	13%	13%	25%	18%	16%	12%	17%
BBB-	13%	13%	13%	13%	13%	11%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	2%
Below BBB-	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	0%
Total	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%

Source: S&P CAPITAL IQ and Market Intelligence, data retrieved 12/31/2024.
Note: Subsidiary ratings used.

B. Use of Historical Authorized ROEs and the Risk Premium Method.

Q HOW DOES MR. D'ASCENDIS RESPOND TO YOUR USE OF HISTORICAL AUTHORIZED ROES IN YOUR ANALYSIS?

A He argues that my reliance on historical authorized returns is misplaced. According to him, those returns were set under different market and regulatory conditions, and therefore do not provide a reliable benchmark for determining the cost of equity today.

He emphasizes that the cost of equity must be forward-looking, reflecting current investor requirements rather than relying on past commission decisions. In his view, using historical averages risks understating today's return requirements.

Q DOES MR. D'ASCENDIS VIEW PAST AUTHORIZED ROES AS REPRESENTATIVE OF THE MARKET COST OF EQUITY?

A. No. He claims that past authorized returns were the product of regulatory compromises and policy considerations, not pure finance theory. Therefore, he argues that they should not be treated as direct evidence of investor-required returns.

Q IF HISTORICAL AUTHORIZED ROES ARE CONSIDERED, WHAT METHOD DOES MR. D'ASCENDIS ARGUE SHOULD BE APPLIED?

A He contends that the appropriate way to use that data is not by presenting simple averages, but by applying a linear Ordinary Least Squares ("OLS") regression model that measures the relationship between the equity risk premium ("ERP") (the difference between authorized ROEs and a corresponding interest rate) and interest rates. He believes this method better captures how regulators have adjusted returns in response to

changes in bond yields over time. He applies a similar methodology in response to my Risk Premium analysis. His OLS regression applied to my underlying data is presented in his Schedule DWD-11R.

Q WHAT ARE THE RESULTS OF HIS OLS REGRESSION ANALYSIS?

A For the Electric Risk Premium (Treasury Bond) analysis, his regression predicts a 5.94% ERP and a ROE of 10.50% assuming a projected 30-year Treasury yield of 4.56%. For the Gas Risk Premium (Treasury Bond) analysis, his regression predicts a 5.88% ERP and a ROE of 10.44%.

For the Electric Risk Premium (A rated Utility Bond) analysis, his regression predicts a 4.69% ERP and a ROE of 10.40% assuming a projected A-rated Utility bond yield of 5.71%. For the Gas Risk Premium (A rated Utility Bond) analysis, his regression predicts a 4.63% ERP and a ROE of 10.34%.

He notes that the R-squareds are both in excess of 82%, meaning that the movement in interest rates explains over 82% of the movement in the ERP, which he considers "to be a strong relationship."

Q DO YOU HAVE ANY GENERAL OBSERVATIONS ABOUT HIS "CORRECTION" TO YOUR RISK PREMIUM ANALYSIS YOU WOULD LIKE TO MAKE?

A Yes. Despite using prospective rates that are generally consistent with those realized in 2024 and 2025, Mr. D'Ascendis' "correction" to my Risk Premium analysis produces results so far removed from authorized returns over that same time period. For example,

his "corrected" version of my Electric Risk Premium over Treasury bonds assumes a prospective 30-year Treasury yield of 4.56%. The 2024 and 2025 average yield on 30-year Treasury bonds was 4.41% and 4.71%, respectively, meaning his prospective yield of 4.56% is squarely in the middle of those observations. During 2024 and year-to-date 2025, the average electric ROE was 9.78% and 9.72%, respectively. This means that the indicated ERP for 2024 and 2025 was 5.37% and 5.01%, respectively. Despite these most recent and relevant observations, Mr. D'Ascendis' "corrected" version of my Risk Premium analysis using OLS regression predicts an ERP of 5.94%, which is significantly higher than the ERP in 2024 or 2025. As a result of his disjointed analysis, his predicted ROE using the OLS regression method of 10.5% is also significantly in excess of the 9.78% and 9.72% average ROEs in 2024 and 2025.

Q DO YOU HAVE ANY CONCERNS WITH THE APPLICATION OF A SIMPLE OLS REGRESSION TO MEASURE THE RELATIONSHIP BETWEEN THE ERP AND INTEREST RATES?

A Yes, I do. The OLS regression model assigns equal weight to all observations over the study period, implicitly assuming that the relationship between the equity risk premium and bond yields has remained stable over that entire period. However, this approach may fail to capture structural changes in the regulatory landscape, investor expectations, and utility ratemaking practices that have occurred over time, particularly in more recent years. As a result, the model may give undue influence to outdated data and underrepresent the conditions currently driving authorized returns. If a regression

model is applied to capture the relationship between interest rates and the ERP, a Weighted Least Squares ("WLS") regression model is more appropriate.

Q WHAT IS WLS REGRESSION, AND WHY DO YOU BELIEVE IT IS MORE USEFUL THAN AN OLS REGRESSION?

A WLS regression is a variation of the traditional OLS regression method. Like OLS, it is used to estimate the relationship between variables such as the ERP and interest rates, but it improves on OLS by allowing certain observations to carry more influence than others based on their relevance or reliability.

OLS regression treats all data points equally, assigning the same weight to each observation regardless of when it occurred. This equal treatment can be problematic when analyzing long historical datasets, particularly when the relationship between variables (like bond yields and the ERP) has evolved over time due to changing market conditions or regulatory environments. For example, an ROE authorized by a state commission in 1988 may have been based on vastly different economic, policy, and risk considerations than one authorized in 2024 or 2025.

WLS regression addresses this by assigning greater weight to more recent data, which better reflects the current relationship between bond yields and the equity risk premium. In this analysis, I used an exponential weighting function that gradually reduces the influence of older data while emphasizing more recent observations. This approach helps ensure the regression model reflects contemporary market conditions more accurately, which is especially important for estimating the current cost of equity.

By using WLS, the goal is to produce a more relevant and timely estimate of the cost of equity for ratemaking purposes—one that better reflects today's utility environment rather than relying equally on data from decades ago that may no longer be representative.

Q WHAT ARE THE RESULTS OF A WLS REGRESSION ANALYSIS FOR THE ELECTRIC AND GAS RISK PREMIUM?

A The results of the WLS regression analysis for the electric and gas risk premium method are summarized below in Table CCW-2SR. I relied on the same data Mr. D'Ascendis used in his "correction" to my Risk Premium study. I also incorporated his prospective Treasury yield of 4.56% and his prospective A-rated utility bond yield of 5.71%. The results range from 9.80% to 9.86%. I will note that the R-squareds range from 0.9418 to 0.9530, all of which are higher than the R-squareds produced by Mr. D'Ascendis' simple OLS regression analysis which he concluded was a "strong relationship."

TABLE CCW-2SR

Bond Yield Plus Risk Premium
Weighted Least Squares Regression Summary Results

	Electric		Gas	
Description	Treasury	A-Rated Util.	Treasury	A-Rated Util.
Intercept (β0)	9.1053	8.8489	9.2518	9.0802
Slope (β1)	-0.8345	-0.8242	-0.8779	-0.8739
Proj. Yield[1]	4.56	5.71	4.56	5.71
Predicted ERP	5.30	4.14	5.25	4.09
ROE Estimate	9.86	9.85	9.81	9.80
R-Square	0.9418	0.9426	0.9530	0.9521

Source: Joint Statement No. 2R at 49.

C. DCF Model

Q PLEASE DESCRIBE MR. D'ASCENDIS' CONCERNS WITH YOUR DCF ANALYSIS.

A Mr. D'Ascendis expresses three concerns with my DCF model. Specifically, he:

- Disagrees with my reasoning to discount the results of my constant growth DCF model using analyst growth rates;
- My use of the sustainable growth rate method in the constant growth DCF model and;

- My use of a multi-stage DCF model.

Q PLEASE RESPOND TO MR. D'ASCENDIS' CONCERN REGARDING YOUR USE OF A PROJECTED GROSS DOMESTIC PRODUCT ("GDP") GROWTH RATE IN YOUR MULTI-STAGE DCF ANALYSIS.

A As a matter of principle, no company's earnings and/or dividends can grow faster than the economy in which it sells goods and services into perpetuity. In the long run, earnings growth will be limited by several factors, including, but not limited to, competition and market saturation. Mr. D'Ascendis' conclusion that GDP growth is not an upper limit for company and industry growth defies the economic and financial literature of which I am aware. In addition to the texts cited in my Direct Testimony[1] in support of the premise that GDP is a long-term cap on growth, I refer Mr. D'Ascendis to the following excerpts. First, as detailed in the Chartered Financial Analyst ("CFA") Institute's curriculum:

> For earnings growth to exceed GDP growth, the ratio of corporate profits to GDP must trend upward over time. It should be clear that the share of profits in GDP cannot rise forever. At some point, stagnant labor income would make workers unwilling to work and would also undermine demand, making further profit growth unsustainable. *Thus, in the long run, real earnings growth cannot exceed the growth rate of potential GDP.*[2] (emphasis added)

Additionally, Dr. Roger A. Morin details in his book, *New Regulatory Finance*, as follows:

[1]Corrected OCA Statement 2 at 39.

[2]CFA Program Curriculum, 2014 Level II Vol.1, "Ethical and Professional Standards, Quantitative Methods, and Economics" Reading 15 – Economic Growth and the Investment Decision, pages 608-609.

> It is useful to remember that eventually all company growth rates, especially utility services growth rates, converge to a level consistent with the growth rate of the aggregate economy.
>
> * * *
>
> […] it is quite possible that a company's dividends can grow faster than the general economy for five years*, but it is quite implausible for such growth to continue into perpetuity.*[3] (emphasis added)

Thus, my use of projected GDP growth as an upper limit for company or industry growth is wholly defensible, regardless of it not being a market measure. Mr. D'Ascendis has provided no substantive evidence to refute the findings of the academic and practitioner texts cited here and in my Direct Testimony on the matter. As such, Mr. D'Ascendis' concerns are unfounded and lack merit.

Q MR. D'ASCENDIS ARGUES THAT YOUR MULTI-STAGE DCF MODEL IS INAPPROPRIATE BECAUSE UTILITIES ARE IN THE STEADY-STATE GROWTH STAGE. HOW DO YOU RESPOND?

A I disagree with Mr. D'Ascendis' conclusion that utilities are in a steady-state growth stage. His characterization overlooks the unprecedented expansion of data centers and the corresponding surge in demand growth that utilities are currently experiencing. This development is not reflective of a mature, flat growth environment. Instead, it represents a significant structural change in the utility industry, with utilities investing heavily in infrastructure to meet rapidly rising load requirements. Given this environment, it is inappropriate to assume utilities are currently settled into steady-state growth. A multi-

[3]Roger A. Morin, New Regulatory Finance, pages 308-309.

stage DCF model is well-suited to capture this dynamic, recognizing higher near-term growth expectations before transitioning to long-run sustainable levels.

Q DID MR. D'ASCENDIS ALSO TAKE ISSUE WITH YOUR SUSTAINABLE GROWTH RATE DCF ANALYSIS?

A Yes, he did. Specifically, he takes issue with the assumption that future earnings growth is inversely related to the dividend payout ratio. He cites studies performed by Zhou and Ruland (2006) and Gwilym, *et al*. (2006), both of which cite the Arnott and Asness (2003) study, in support of his argument.[4]

Q PLEASE RESPOND.

A As an initial matter, no model is perfect, and at times can be more or less accurate than other models depending on various factors, such as economic conditions. As Mr. D'Ascendis states in his Direct Testimony, "[…] the use of multiple generally accepted common equity cost rate models also adds reliability and accuracy when arriving at a recommended common equity cost rate."[5] I agree using multiple methods provides a more comprehensive, and therefore, more reliable perspective on investors' return requirements. For this reason alone, it is important to perform a thorough analysis, and apply informed, reasoned judgement in the interpretation of the results. The use of multiple DCF models and considering those results is consistent with that approach.

[4]Citizens/Valley/Wellsboro Joint Statement No. 2R at 39-40.
[5]Citizens/Valley/Wellsboro Joint Statement No. 2 at 21.

In addition, using the retention growth methodology is a recognized reasonable method for estimating sustainable dividend growth and should not be ignored.

As noted by the CFA Institute's curriculum text:

> "We define the sustainable growth rate as the rate of dividend (and earnings) growth that can be sustained for a given level of return on equity, assuming that the capital structure is constant through time and that additional common stock is not issued. The reason for studying this concept is that it can help in estimating the stable growth rate in a Gordon growth model valuation, or the mature growth rate in a multistage DDM in which the Gordon growth formula is used to find the terminal value of the stock."

The expression to calculate the sustainable growth rate is:
$g = b$ x ROE[6]

Notably, the same CFA text observes that, in light of the Arnott and Asness (2003) study cited by Mr. D'Ascendis, "caution is appropriate in assuming that dividends displace earnings."[7] However, that same text concludes that "[n]evertheless, the equation can be useful as a simple expression for approximating the average rate at which dividends can grow over a long horizon."[8] Further, *Brigham and Houston* state that, "Companies that retain a high percentage of their earnings rather than paying them out as dividends generate more retained earnings and thus need less external capital."[9]

[6]*See* CFA Program Curriculum, 2014, Level II, Volume 4, "Dividend Discount Valuation," at page 264.

[7]*See* CFA Program Curriculum, 2014, Level II, Volume 4, "Dividend Discount Valuation," at pages 265-266.

[8]*Ibid.* at 266.

[9]*See Fundamentals of Financial Management*, Eugene F. Brigham and Joel F. Houston, Eleventh Edition 2007, Thomson South-Western, a Division of Thomson Corporation at page 558.

D. CAPM

Q PLEASE SUMMARIZE MR. D'ASCENDIS' CONCERNS WITH YOUR CAPM ANALYSIS.

A At page 51 of his Rebuttal Testimony, Mr. D'Ascendis expresses four general concerns with my CAPM analysis: (1) he argues I violated the Efficient Market Hypothesis ("EMH") by failing to include farthest out projected interest rates; (2) he disagrees with certain of my beta estimates; (3) he disagrees with my use of Kroll's recommended Market Risk Premium ("MRP"), and (4) he argues I should have included an Empirical CAPM analysis.

Q PLEASE RESPOND TO MR. D'ASCENDIS' ASSERTION THAT YOU VIOLATED THE EMH BY NOT INCORPORATING THE LONGEST AVAILABLE PROJECTED RISK-FREE RATE.

A Mr. D'Ascendis' assertion is misplaced and inconsistent with his own testimony. Under the semi-strong form of the EMH, which Mr. D'Ascendis is asserting, it is assumed securities prices reflect all publicly available information and past market data. Because Blue Chip is a paid subscription, not all investors necessarily have access to the data and therefore it would be hard to classify the projections offered by Blue Chip as public, a classification that is required under the semi-strong form of EMH.

Further, to the extent Mr. D'Ascendis failed to include all publicly available data, both historical and projected, he himself violated the EMH.

Q DO YOU HAVE ANY GENERAL COMMENTS IN RESPONSE TO MR. D'ASCENDIS WITH REGARD TO THE METHODS USED TO CALCULATE THE EXPECTED MARKET RETURN, AND ULTIMATELY, THE EXPECTED MRP.

A Yes. Regardless of the method used to calculate the expected market return, they all produce expected MRPs in the range of 5.50% to 8.00%. These estimates of the MRP are fully supported by financial texts and empirical research. For example, Dr. Morin notes several studies of the MRP in his book, *Modern Regulatory Finance*, have concluded that a MRP in the range of 5.0% to 8.0% is a reasonable estimate for the United States.[10] For example, the Duarte and Rosa study he cites, concludes that it is "quite difficult to improve upon when considering out-of-sample performance measures."[11] Dr. Morin also notes that a survey of professional practices showed that 71% of textbooks/tradebooks used a historical average as the MRP, and 60% of financial advisors used a MRP in the range of 7.0% to 7.4%, or a long-term arithmetic average.[12] My MRPs, regardless of the method used to calculate the expected market return component, is supported by substantial empirical evidence. Mr. D'Ascendis' concerns are unsupported and lack merit.

Q MR. D'ASCENDIS ARGUES THAT YOUR USE OF KROLL'S RECOMMENDED MRP OF 5.00% SHOULD BE REJECTED IN FAVOR OF OTHER MRP'S CITED IN KROLL. HOW DO YOU RESPOND.

[10]Dr. Morin references studies by Duarte & Rosa; Professors Ross, Westerfield, and Jordan; Mahera; and Brealey, Myers, and Allen. *See Modern Regulatory Finance,* Dr. Roger Morin, at 190-192.
[11]*See Modern Regulatory Finance,* Dr. Roger Morin, at 191, citing the Duarte and Rosa study.
[12]*See Modern Regulatory Finance,* Dr. Roger Morin, at 190, footnote 35.

A Mr. D'Ascendis states, erroneously, that I relied on an MRP of 5.00% as recommended by Kroll.[13] However, Kroll's recommended MRP that I relied on is actually 5.50%, not 5.00% as alleged by Mr. D'Ascendis. Kroll's recommended MRP is well within the range of well-known empirical data. For example, Dr. Morin notes in his book, *Modern Regulatory Finance*, that several studies of the MRP have concluded that a MRP in the range of 5.0% to 8.0% is a reasonable estimate for the United States.[14]

In addition, Mr. D'Ascendis seems to ignore the significant support from *Kroll* describing their recommended normalized, or conditional market risk premium. Specifically, Kroll's recommended risk premium is not explicitly based on any particular set of returns, but rather it is a conditional risk premium based on observations of relevant factors including, but not limited to fluctuations in global economic and financial market conditions. Kroll explains its equity risk premium methodology on its Cost of Capital Navigator site as follows:

> There is no single universally accepted methodology for estimating the ERP; consequently, there is wide diversity in practice among academics and financial advisors regarding ERP estimates. In estimating the conditional ERP, valuation analysts cannot simply use the long-term historical ERP, whether as reported or adjusted as we discussed above. A better alternative would be to examine approaches that are sensitive to the current economic conditions.
>
> Kroll employs a multi-faceted analysis to estimate the conditional ERP that takes into account a broad range of economic information and multiple ERP estimation methodologies to arrive at its recommendation.
>
> First, a reasonable range of normal or unconditional ERP is established.

[13]Joint Statement No. 2R at 53.

[14]Dr. Morin references studies by Duarte & Rosa; Professors Ross, Westerfield, and Jordan; Mahera; and Brealey, Myers, and Allen. See *Modern Regulatory Finance,* Dr. Roger A. Morin, at 190-192. Dr. Morin notes in his textbook that there is a "slight preference" for the upper end of the range (i.e., 8%) during tumultuous times in capital markets with examples being the 2008-2009 credit crisis and the 2020 pandemic.

> Second, based on current economic conditions, Kroll estimates where in the range the true ERP likely lies (top, bottom, or middle) by examining the current state of the economy (both by examining economic indicators and forecasts, as well as by analyzing the level and trends of stock market indices as forward indicators), in conjunction with the implied equity volatility and corporate spreads as indicators of perceived risk.

Mr. D'Ascendis' concern with the Kroll market risk premium is clearly misplaced. Kroll is one of the most often cited names in valuation and cost of capital matters, particularly regarding cost of capital testimony offered in regulated utility proceedings such as this one.

Q PLEASE RESPOND TO MR. D'ASCENDIS WITH REGARD TO YOUR USE OF VASICEK BETAS FROM S&P CAPITAL IQ.

A S&P Capital IQ is one of the most cited sources of financial data and other relevant utility industry information by rate of return witnesses in cost of capital testimony throughout the country. Further, S&P Capital IQ is one of the most recognized names in finance. Investors rely on data from S&P Capital IQ, particularly in the utility sector, to inform their investment making decisions.

Q IS THERE FINANCIAL LITERATURE DISCUSSING THE VASICEK METHOD OF ADJUSTING BETA IN COMPARISON TO THE BLUME METHOD EMPLOYED BY *VALUE LINE*?

A Yes. In an article titled "An Examination of Blume and Vasicek Betas" published in the journal *The Financial Review,* Martin Lally discusses the merits of both methods of adjusting beta. An observation made by Lally as it relates to the utility industry is as follows:

> A dramatic example of this is in U.S. electric utilities. A typical such firm has an estimated beta (unadjusted) of around 0.4 (Value Line, 1993). By virtue of being typical, the Vasicek estimate, with prior corresponding to this industry, will also be 0.4. By contrast, Blume adjusts the 0.4 to 0.6 [i.e. 0.33 + 0.67(0.4)]. The result is a dramatic overestimate by Blume, because a singularly relevant fact is ignored, i.e., membership of an industry whose average estimated, and therefore presumably also true, beta is well below one. Given that these firms have output prices that are set so as to recover costs, including the cost of equity, and they have substantial equity investment, then the implications of using Blume betas (i.e., not partitioning into industries) for measuring costs of equity are particularly severe.[15]

Mr. D'Ascendis' concerns with Vasicek-adjusted betas are unsupported and lack merit.

Q PLEASE RESPOND TO MR. D'ASCENDIS WITH REGARD TO YOU NOT PERFORMING AN ECAPM ANALYSIS.

A At page 57 of his Rebuttal Testimony, Mr. D'Ascendis simply states that my CAPM methodology is flawed because, among other reasons, I did not perform an ECAPM analysis. I explained in detail why I disagree with the use of an ECAPM, particularly with an adjusted beta, in my Direct Testimony at pages 74-77. Mr. D'Ascendis has offered nothing substantive to alter my opinion on the matter.

Q IS IT NECESSARY TO PERFORM AN ECAPM AT THIS TIME?

A No, as I explain in my Direct Testimony, the purpose of the adjustments presented in the ECAPM is to raise the intercept and flatten the security market line ("SML"). The applications of the "traditional" CAPM offered by the witnesses in this proceeding are

[15]The Financial Review, Vol. 33 (1998) at 183-198, "An Examination of Blume and Vasicek Betas," Martin Lally. (Emphasis Added).

anything but "traditional" given the extensive use of projected long-term yields and adjusted betas, both of which raise the intercept and flatten the SML.

For example, the use of a projected 30-year Treasury yield is a departure from the traditional CAPM in two regards. First, projected yields as those employed by myself in this proceeding are generally higher than spot yields which were used in the traditional form of the CAPM. Second, long-term yields, as employed by some witnesses in this proceeding, are generally higher than short-term yields, which were used in the traditional form of the CAPM. Each of these revised inputs accomplishes a key goal of the ECAPM by raising the intercept and flattening the slope of the SML.

Further, as I demonstrated in my Direct Testimony, the use of an adjusted beta as published by *Value Line* also raises the intercept and flattens the slope of the SML. As such, the application of the "traditional" CAPM in this proceeding has accomplished the goal of the ECAPM by implementing several inputs that raise the intercept and flatten the SML. Specifically, I am referring to forecasted long-term Treasury yields being used in favor of short-term spot yields and adjusted betas. Therefore, I maintain my position on the ECAPM.

E. D'Ascendis' Performance Factor Adjustment

Q MR. D'ASCENDIS CONTINUES TO RECOMMEND A FIVE-BASIS POINT UPWARD ADJUSTMENT TO THE ROE UNDER 66 PA.C.S. § 523 FOR "MANAGEMENT EFFICIENCY." DO YOU AGREE?

A No, I do not. While I am not an attorney or offering a legal opinion, it is my understanding that Section 523 does not mandate a performance adjustment to the return

on equity for management efficiency; it requires the Commission to consider the efficiency, effectiveness and adequacy of utility service when determining just and reasonable rates and provides the Commission with discretion to make adjustments to specific components of the utility's claimed cost of service as it determines to be proper and appropriate in determining just and reasonable rates. It is my understanding Section 523 does not provide an entitlement, and the Commission is under no obligation to award a premium for utilities simply meeting their statutory obligations.

Q HOW DOES THIS PERFORMANCE PREMIUM PROPOSAL SQUARE WITH THE STANDARDS IN HOPE AND BLUEFIELD?

A It does not. The standards set forth in Hope and Bluefield assume that a utility's authorized return is based on the presumption of sound, economic, and efficient management. That standard is built into the regulatory compact itself. Awarding a separate upward adjustment for "management efficiency" would double count what is already assumed and required by law.

Q WHAT IS THE RISK OF ADOPTING A PERFORMANCE FACTOR ADJUSTMENT AS MR. D'ASCENDIS PROPOSES?

A Such an adjustment risks creating an artificial premium that overcompensates shareholders for management behavior that is expected. Utilities are legally obligated to provide safe and adequate service at just and reasonable rates. Efficiency is not an optional standard deserving of an extra ROE; it is the baseline expectation under regulatory precedent.

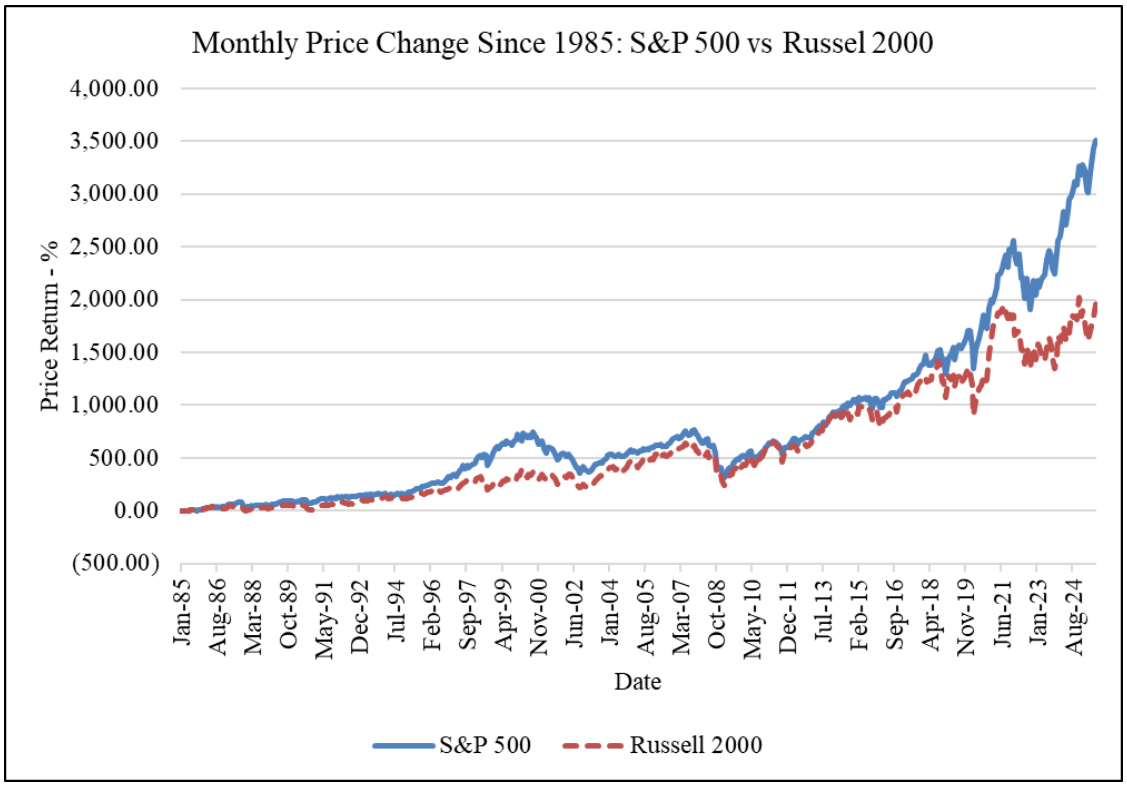
Q HOW SHOULD THE COMMISSION TREAT MR. D'ASCENDIS'S REQUEST?

A The Commission should reject it. Section 523 does not compel a performance factor adjustment and granting one would directly contradict Hope and Bluefield. The proper application of those precedents is to set a fair return that presumes efficient management, not to layer on an additional reward for simply meeting fundamental obligations.

F. D'Ascendis' Size Adjustment

Q MR. D'ASCENDIS TAKES ISSUE WITH YOUR FAILURE TO ADJUST YOUR RECOMMENDATION UPWARD TO ACCOUNT FOR SIZE. DOES HIS REBUTTAL TESTIMONY CHANGE YOUR POSITION ON THE MATTER?

A No. I continue to maintain my conclusion that a size adjustment is unnecessary. Trends in the returns of large capitalization stocks (i.e. the S&P 500) versus small capitalization stocks (i.e. the Russel 2000) show that small capitalization stock returns lag those produced by large capitalization stock returns. As shown in Figure CCW-1SR, the returns that used to be produced by investing in small capitalization stocks have disappeared in recent years, as the S&P 500 returns far exceed the returns compared to its small capitalization stock counterpart, the Russel 2000 index.



Finally, I&E Witnesses Keller and Patel (collectively the "I&E Witnesses"), and I all cite empirical evidence which concludes that, while size premiums are present in industrial companies, such a size premium is not present in utility companies, nor are they appropriate to include in valuing utilities. Mr. D'Ascendis cites an article by Dr. Thomas Zepp as a response to the evidence cited by the I&E Witnesses and me. Dr. Zepp's 2003 article is a narrow short communication that does not provide reliable support for applying a size adjustment in utility cost of equity determinations. While it critiques Wong's earlier work (the research article cited by the I&E witnesses and me), Dr. Zepp's analysis is incomplete, methodologically limited, and focused almost exclusively on a handful of small water utilities. This narrow evidence base is not sufficient to establish that a systematic size effect exists for utilities generally, let alone for electric or gas distribution companies.

Further, Dr. Zepp's recalculated betas are based on just three water companies, and his discounted cash flow study finds an average 99 basis point premium for small utilities that is only significant at the 90% confidence level. Typically, 95% is the standard confidence level used.

For these reasons, the size premium adjustment proposed by Mr. D'Ascendis is unsupported and lacks merit.

G. D'Ascendis' Updated Analysis

Q DID MR. D'ASCENDIS OFFER AN UPDATED COST OF EQUITY ANALYSIS IN HIS REBUTTAL?

A Yes, he did. The indicated range of ROEs attributable to Valley are from 10.42% to 10.89% (unadjusted) and from 11.47% to 11.94% (adjusted) and the indicated range of ROEs attributable to Citizens' and Wellsboro are from 10.19% to 10.76% 8 (unadjusted) and from 11.09% to 11.66% (adjusted). Each of the flaws that were present in Mr. D'Ascendis' analysis that I described in my direct testimony are present in his updated analysis. As such, Mr. D'Ascendis' updated analysis is still overstating the cost of equity for the Companies.

Q DOES THIS CONCLUDE YOUR SURREBUTTAL TESTIMONY?

A Yes, it does.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No. R-2025-3054394
	:	R-2025-3054393
Citizens' Electric Company of Lewisburg, PA, Valley Energy, Inc., and Wellsboro Electric Company	:	R-2025-3054392

VERIFICATION

I, Christopher C. Walters, hereby state that the facts above set forth in my Surrebuttal Testimony, OCA Statement No. 2SR, are true and correct to the best of my knowledge, information, and belief and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa.C.S. § 4904 (relating to unsworn falsification to authorities).

DATED: August 28, 2025

Signature: */s/ Christopher C. Walters*
Christopher C. Walters

Address: Brubaker & Associates, Inc.
16690 Swingley Ridge Road
Suite 140
Chesterfield, MO 63017

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	Docket No.: R-2025-3054394
v.	:	
	:	
Citizens' Electric Company of Lewisburg	:	

SURREBUTTAL TESTIMONY

OF

Michael Deupree

On behalf of the

PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

OCA Statement 3SR

Date Served: August 28, 2025

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS?

A. My name is Michael W. Deupree. My business address is 5800 One Perkins Place Drive, Suite 5-F, Baton Rouge, Louisiana, 70808.

Q. HAVE YOU PREVIOUSLY FILED TESTIMONY IN THIS PROCEEDING?

A. Yes. I filed direct and rebuttal testimony in this proceeding on July 15, 2025, and August 13, 2025, respectively, on behalf of the Pennsylvania Office of Consumer Advocate ("OCA").

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to respond to elements of the rebuttal testimonies of Howard S. Gorman on behalf of Citizens' Electric Company of Lewisburg ("Citizens" or the "Company"), and Justin B. Farr on behalf of the Pennsylvania Office of Small Business Advocate ("OSBA"). Specifically, I will respond to Citizens and OSBA's discussion on the use of a zero-load analysis to classify a portion of electric distribution costs as customer related, and Citizens' response to my proposed revenue allocation and analysis of customer-related costs.

II. CLASSIFICATION OF ELECTRIC DISTRIBUTION COSTS

Q. PLEASE SUMMARIZE COMPANY WITNESS GORMAN'S RESPONSE TO YOUR CLASSIFICATION OF THE SECONDARY PORTION OF DISTRIBUTION PLANT ACCOUNTS 364-368.

A. Mr. Gorman argues that classification of the secondary portion of distribution plant accounts 364-368 as 100 percent demand-related is problematic on several levels. First, he disputes my assertion that zero-load analyses are meaningless due to reliance on the

theoretical construct of a system incapable of having load-carrying capabilities.[1] Second, he argues that my direct testimony ignores important findings by Professor Bonbright in his treatise on rate design.[2] Finally, Mr. Gorman disregards my empirical findings showing a lack of statistical correlation between changes in customer counts and distribution system investments as making no sense on a prima-facie basis.[3]

Q. PLEASE SUMMARIZE OSBA WITNESS FARR'S RESPONSE TO YOUR CLASSIFICATION OF THE SECONDARY PORTION OF DISTRIBUTION PLANT ACCOUNTS 364-368.

A. OSBA witness Farr notes that the Company's Allocated Cost of Service ("ACOS") study classified all of FERC Account 368 (line transformers) as demand-related, which is inconsistent with the Company's testimony representations.[4] He also asserts that the NARUC Manual references accounts 364-368 as containing both customer and demand-related components.[5]

Q. WHY DOES MR. GORMAN ARGUE THAT ZERO-LOAD ANALYSES SERVE AS USEFUL TOOLS TO SEPARATE COSTS BETWEEN DEMAND-RELATED AND CUSTOMER-RELATED FUNCTIONS?

A. Mr. Gorman argues that my critiques about the classification of secondary distribution plant accounts represent "often-used but misleading argument."[6] Specifically,

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[1] Rebuttal Testimony of Howard S. Gorman at 9:15-18 and 10:3-7.

[2] *Id.* at 10:11-14.

[3] *Id.* at 10:21-22.

[4] Rebuttal Testimony of Justin B. Farr at 2:11-19.

[5] *Id.* at 4:11 to 5:1.

[6] Rebuttal Testimony of Howard S. Gorman at 9:15.

he notes that he acknowledges that his zero-load analysis and related Minimum Size System ("MSS") analyses are theoretical constructs, but he argues that this is not a valid reason to reject the results of such analyses.[7] Instead, Mr. Gorman argues that these analyses represent "useful tools," to separate costs between demand-related and customer-related functions, regardless of the fact that no such system would be constructed in reality.[8] Mr. Gorman notes as evidence that it would be possible to install transformers with ratings of 12.5 kVA for customers where this is sufficient to meet demand, and to install larger capacity transformers only where needed.[9]

Q. DO YOU AGREE WITH COMPANY WITNESS GORMAN'S ARGUMENTS ABOUT THE POTENTIAL VALIDITY OF ZERO-LOAD AND MSS ANALYSES?

A. No. Mr. Gorman appears to have misunderstood that my critique is that the theoretical nature of these analyses is an inherent flaw of the analyses. The conceptual purpose of a zero-load analysis is supposedly to identify the system costs that are associated with a hypothetical electric distribution system that serves all customers on its system as connections but which **cannot** serve customer loads (or "zero-load") and thus **cannot** serve these connected customers. This contradiction in purpose is why such a system would never exist, which furthermore creates inherent problems highlighted by Mr. Gorman's statement concerning transformer capacity. Mr. Gorman's zero-load analysis estimates a replacement cost for the Company's inventory of transformers that

[7] *Id.* at 9:15-17.

[8] *Id.* at 9:17-18.

[9] *Id.* at 9:19-23.

range in capabilities from 15 to 1500 kVA.[10] As Mr. Gorman acknowledges, these replacement transformers, even a minimum-size system, **would be sufficient** to meet many customers' demand requirements, a direct violation of the conceptual purpose of a zero-load analysis which is to estimate the costs of a hypothetical electric distribution system **that is not sufficient** to meet customers' demand requirements.

Q. HAS AUTHORITATIVE SOURCES COMMENTED ON THIS CONCERN ASSOCIATED WITH MSS ANALYSES?

A. Yes. As I referenced in my direct testimony, the National Association of Regulatory Utility Commissioners ("NARUC") Electric Cost Allocation Manual ("NARUC Manual") specifically recognizes this fundamental failing of zero-load analyses in its discussion noting that "… the analyst must be aware that the minimum-size distribution equipment has a certain load-carrying capability, **which can be viewed as a demand-related costs**."[11] Essentially, a direct reliance on replacement costs, as the Company has done in the current proceeding for line transformers, would **necessarily over-estimate** the customer-related portion of the equipment costs, even if one accepts the premise of a zero-load or MSS analysis.

Q. IS IT POSSIBLE TO ESTIMATE THE COST OF A ZERO-LOAD SYSTEM?

A. No. When done appropriately, a zero-load analysis would involve estimating the costs of an electric distribution system which cannot function as an electric distribution system. For example, a correct zero-load analysis would require the estimation of the cost of an 'electric line transformer' which cannot function as an electric line transformer

[10] Company's Response to Data Request I&E-RE-1-D Attachment A, WP2_D.

[11] Direct Testimony of Michael W. Deupree at 17:23 to 18:2, *emphasis added.*

– effectively an empty box. Even if one could estimate the costs of this farcical 'electric line transformer,' it would be impossible to verify these estimates with any degree of analytical rigor required in the setting of just and reasonable rates.

Q. DOES THIS FLAW ALSO HOLD TRUE FOR MR. GORMAN'S ESTIMATION OF ZERO-LOAD COSTS ASSOCIATED WITH POLES, OVERHEAD AND UNDERGROUND CONDUCTORS?

A. Yes. Mr. Gorman's zero-load analysis does not include material costs in his analysis of the zero-load costs associated with secondary electric distribution poles, and overhead and underground conductors (i.e. lines), instead only estimating the labor, overhead, and vehicle costs associated with replacement. However, even this analysis does not truly estimate the costs of a zero-load replacement system as it assumes this replacement system would contain the same number of circuit miles as Citizens current system which was designed with customer's load requirements in mind.[12] A true zero-load replacement system would certainly contain fewer circuit miles compared to Citizens' current system.

Q. DO YOU AGREE WITH MR. GORMAN'S CHARACTERIZATION OF PROFESSOR BONBRIGHT'S STATEMENTS ON CLASSIFYING MINIMUM-SIZED DISTRIBUTION SYSTEM COSTS AS CUSTOMER-RELATED?

A. No. Mr. Gorman selectively quotes Professor Bonbright's treatise on the issue out of context. Professor Bonbright's full quote for the record is provided below, and clearly

[12] Company's Response to Data Request I&E-RE-1-D Attachment A, D1.

shows his negative opinion on classifying minimum-sized distribution system costs as customer-related.

> While, for the reason just suggested, **the inclusion of the costs of a minimum-sized distribution system among the customer-related costs seems to us clearly indefensible**, its exclusion from the demand-related costs stands on much firmer ground. For this exclusion of minimum-sized distribution system costs makes more plausible the assumption that the *remaining* cost of the secondary distribution system is a cost which varies continuously (and, perhaps, even more or less directly) with the maximum demand imposed on this system as measured by peak load.
>
> But if the hypothetical cost of a minimum-sized distribution system is properly excluded from the demand-related costs for the reason just given, while it is also denied a place among the customer costs for the reason stated previously, to which cost function does it then belong? **The only defensible answer, in our opinion, is that it belongs to none of them**. Instead, it should be recognized as a strictly unallocable portion of total costs. And this is the disposition that it would probably receive in an estimate of long-run marginal costs. But fully-distributed cost analysts dare not avail themselves of this solution, since they are the prisoners of their own assumption that "the sum of the parts equals the whole." They are therefore under impelling pressure to fudge their cost apportionments **by using the category of customer costs as a dumping ground for costs that they cannot plausibly impute to any of their other cost categories**.[13]

Q. WHY DOES PROFESSOR BONBRIGHT FIND THAT CLASSIFYING MINIMUM-SYSTEM COSTS AS CUSTOMER-RELATED "CLEARLY INDEFENSIBLE?"

A. Professor Bonbright notes the lack of empirical support in academic literature for a causal relationship between distribution system investments and changes in the number of customers on the system. A relationship, or rather lack thereof, which I showed in my

[13] James C. Bonbright, *et al.* Principles of Public Utility Rates. 1988 Edition. Arlington, VA: Public Utilities Reports, Inc., pp. 491-492; *emphasis added.*

direct testimony can also be seen when examining historic Citizens' distribution system investments.[14]

Q. WHAT IS WITNESS GORMAN'S RESPONSE TO YOUR EMPIRICAL ANALYSIS OF THE LACK OF A CAUSAL RELATIONSHIP BETWEEN ELECTRIC DISTRIBUTION SYSTEM INVESTMENTS AND CHANGES IN THE NUMBER OF CUSTOMERS ON THE SYSTEM?

A. Mr. Gorman dismisses the conclusion of my analysis showing little to no correlation between electric distribution system investments and changes in the number of customers on the system, as not making sense.[15] Mr. Gorman again appears to have misunderstood my complaint by correctly noting that it must make investments in its distribution system even during years when it experiences decreases in customer counts.[16] This is because a sizable portion of most electric distribution system investments are non-growth related, but instead associated with public policy such as improving/maintaining system reliability.[17] However, this recognition of the lack of a direct causal relationship between growth in customer counts and electric distribution investments undermines the very premise of attempting to classify a portion of such investment costs as customer-related, as Professor Bonbright observed decades ago, and which Mr. Gorman appears to agree with here, at least to an extent.

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[14] Direct Testimony of Michael W. Deupree at 20:11 to 21:6.

[15] Rebuttal Testimony of Howard S. Gorman at 10:21-22.

[16] *Id.* at 10:22-23.

[17] *See*, Rebuttal Testimony of Howard S. Gorman at 10:23 to 11:5.

Q. WHAT IS YOUR RESPONSE TO OSBA WITNESS FARR'S CLAIMS THAT THE NARUC MANUAL PROVIDES THAT SECONDARY ELECTRIC DISTRIBUTION PLANT ASSETS CONTAIN BOTH DEMAND AND CUSTOMER COMPONENTS?

A. Mr. Farr's assertion is inaccurate as to the NARUC Manual because the NARUC Manual does not provide that secondary electric distribution plant assets contain both demand and customer components. Rather, as noted in the NARUC Manual preface, the manual is not intended to advocate for any one particular cost allocation method, but rather discuss all methods that are currently used.[18] Indeed, the NARUC Manual references the controversial classification of substations, poles, transformers, and conductors between demand and customer classifications. Contrast with the less controversial classification of distribution plant accounts 369-373 covering services, meters, street lights, and equipment installed on customer premises, which are generally recognized as fully customer-related and whose costs are either directly assigned to relevant customers or otherwise allocated based on a measure of customer accounts. Indeed, the NARC Manual provides as follows:

> The preceding discussion of the merits of minimum-system versus the zero-intercept classification schemes will affect the major distribution-plant accounts for FERC Accounts 364 through 368. Several other plant accounts remain to be classified. While the classification of the following distribution-plant accounts is an important step, **it is not as controversial as the classification of substation, poles, transformers, and conductors.**[19]

[18] Electric Utility Cost Allocation Manual (January 1992), NARUC, p. ii.

[19] *Id.* at pp. 95-96; *emphasis added.*

III. REVENUE ALLOCATION

Q. DOES COMPANY WITNESS GORMAN SUPPORT YOUR PROPOSED REVENUE ALLOCATIONS?

A. No. Mr. Gorman asserts that my proposed revenue allocations are not supported because they are based on what he asserts is my faulty alternative ACOS study, which he asserts fails to recognize any customer component to the secondary electric plant. Mr. Gorman did recognize my stated concern regarding the large increase in Municipal Boulevard Lighting ("MBL") rates,[20] and is now proposing that the proposed rate increase to this class be capped at 1.50 times the system average increase.[21]

Q. HOW DO YOU RESPOND TO MR. GORMAN STATEMENTS?

A. My alternative ACOS presented in my direct testimony is not faulty and provides a fair and reasonable estimation of relative costs of service between Citizens' customer classes. As I summarize in my direct testimony, Mr. Gorman's inappropriate classification of costs associated with secondary-voltage distribution plant accounts 364-368 skews the allocation of costs and revenue responsibilities away from larger customers and onto residential customers and small commercial customers.[22] MSS and related zero-load analyses depend on deeply flawed premises that have been criticized on theoretical and empirical grounds for decades.[23] As I showed in my direct testimony, there is no statistically significant relationship between changes in average number of customers on

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[20] *Id.* at 13:1-3.

[21] *Id.* at 3:12-14.

[22] Direct Testimony of Michael W. Deupree at 23:12-18.

[23] *See*, *Id.* at 18:13 to 20:4.

Citizens' system and the utility's investment in distribution plant accounts 364-368, highlighting this empirical criticism.[24] It is important that the just and reasonable rates be based on an ACOS that corrects for this flaw.

Q. DO YOU HAVE A RESPONSE TO MR. GORMAN'S REDUCED INCREASE IN MBL RATES?

A. Yes. As shown in my Direct Testimony, Mr. Gorman's initial proposal would have seen base MBL distribution rates increase by 75.0 percent, or 2.53 times the overall Company system-average increase in distribution rates of 29.64 percent.[25] This large increase is inconsistent with principles of gradualism, so I recommended that the proposed rate increase to this class be capped at 1.25 times the overall system-average increase.[26] While Mr. Gorman's rebuttal proposal to cap the increase in MBL distribution rates to 1.50 times the system average is encouraging progress from the Company's initial proposal in this proceeding, I still find my proposed cap equal to 1.25 times the overall system-average increase to be more consistent with principles of gradualism.

[24] *Id.* at 20:6 to 21:5.

[25] Direct Testimony of Michael W. Deupree at 25.

[26] *Id.* at 28:5-10.

IV. CUSTOMER CHARGE

Q. DID MR. GORMAN AGREE WITH YOUR PROPOSAL TO REJECT ANY PROPOSED INCREASES IN EXISTING CUSTOMER CHARGES?

A. No. Mr. Gorman disagrees with my arguments regarding customer charges for multiple reasons. First, he argues that his analysis of customer-related costs was restricted to only customer-related expenses and therefore I did not identify any significant flaw in his computation of customer-related costs.[27] Second, Mr. Gorman disagrees with my regional peer group used to compare the Company's rates, instead arguing that the Company's proposed rates should be compared to its neighboring utility, PPL Electric Utilities Corporation.[28] Finally, Mr. Gorman disagrees with my concerns regarding the negative impacts of higher customer charges on energy conservation, noting that the Company's proposed customer charge recovers only 23 percent of monthly distribution charges for the typical residential customer.[29]

Q. HOW DO YOU RESPOND TO MR. GORMAN'S ARGUMENT THAT YOU DID NOT IDENTIFY ANY SIGNIFICANT FLAW IN THE COMPANY'S COMPUTATION OF CUSTOMER-RELATED COSTS?

[27] Rebuttal Testimony of Howard S. Gorman at 13:13-16.

[28] *Id.* at 13:19-22.

[29] *Id.* at 14:7-12.

A. First, Mr. Gorman's analysis of customer-related costs is flawed because it does include costs associated with line transformers (FERC Account 368). However, ignoring this element, Mr. Gorman's analysis is also flawed in that it assumes the Company's requested rate of return on rate base ("ROR") of 8.49 percent in calculating the required return on customer-related rate base, as I discussed in my rebuttal testimony.[30] The Company's requested ROR is dependent on the Commission's finding of a just and reasonable ROR at the end of this proceeding and therefore is unknown at the current juncture. I therefore based my analysis of customer-related costs on the Company's estimated ROR under current rates of 1.46 percent.[31]

[30] Rebuttal Testimony of Michael W. Deupree at 2:10-13.

[31] *Id.* at 2:15-17.

Table 1: Survey of Customer Charges based on Peer ROE Group

Company	State	Residential Customer Charge ($/month)	Commercial Customer Charge ($/month)
Citizens Electric Company (Current)	**PA**	**$ 13.10**	**$ 16.00**
Citizens Electric Company (Proposed)	**PA**	**$ 16.50**	**$ 21.00**
Alabama Power	AL	14.50	25.00
Oklahoma Gas and Electric Co.	AR	9.75	25.00
Entergy Arkansas	AR	8.40	24.25
Southwestern Electric Power Co.	AR	11.97	14.28
Arizona Public Service Co.	AZ	13.93	38.58
Southern California Edison	CA	10.52	14.24
Public Service Company of Colorado	CO	12.20	20.40
Duke Energy Florida	FL	13.83	17.85
Georgia Power	GA	14.00	36.00
Interstate Power and Light Co.	IA	15.50	23.00
Idaho Power Company	ID	15.00	25.00
Ameren Illinois Co.	IL	6.77	18.15
Duke Energy Indiana	IN	13.70	13.91
Indiana Michigan Power Co.	IN	15.00	29.00
Evergy Kansas Central	KS	14.25	25.29
Evergy Kansas Metro	KS	14.25	17.70
Duke Energy Kentucky	KY	16.00	15.00
Kentucky Power Co.	KY	20.00	28.00
Entergy Louisiana - Gulf States	LA	10.00	13.39
Entergy Louisiana	LA	10.00	9.82
Entergy New Orleans	LA	8.07	0.00
Southwestern Electric Power Co.	LA	7.43	26.17
Northern States Power Co.	MI	9.00	11.50
Indiana Michigan Power Co.	MI	7.58	23.30
Northern States Power Co.	MN	6.00	6.00
Union Electric Co.	MO	9.00	13.46
Evergy Missouri Metro	MO	12.00	18.69
Evergy Missouri West	MO	12.90	10.00
Mississippi Power	MS	48.67	51.71
Entergy Mississippi	MS	31.82	53.10
NorthWestern Energy	MT	4.20	22.05
Duke Energy Carolinas	NC	14.00	21.00
Duke Energy Progress	NC	14.00	22.00
Northern States Power Co.	ND	15.00	16.75
PNM	NM	10.94	22.85
Southwestern Public Service Co.	NM	11.20	21.50
Duke Energy Ohio	OH	8.00	12.00
Ohio Power Company	OH	10.00	9.40
Oklahoma Gas and Electric Co.	OK	13.00	50.95
Public Service Company of Oklahoma	OK	17.00	58.63
Idaho Power Company	OR	10.00	9.50
Portland General Electric Co.	OR	13.00	24.00
Duke Energy Carolinas	SC	11.96	13.50
Duke Energy Progress	SC	11.78	14.00
NorthWestern Energy	SD	7.00	12.00
Northern States Power Co.	SD	8.30	9.05
Kingsport Power Co.	TN	16.43	22.03
Texas-New Mexico Power Co.	TX	7.85	24.56
Xcel Energy	TX	12.45	16.00
Entergy Texas	TX	14.00	21.94
Southwestern Electric Power Co.	TX	9.42	13.06
Appalachian Power Co.	VA	7.96	9.88
Wisconsin Power and Light Co.	WI	15.00	17.00
Northern States Power Co.	WI	15.00	15.00
Appalachian Power Co. & Wheeling Power Co.	WV	12.50	15.00
Peer Group Average		**$ 12.76**	**$ 20.75**

Q. DO YOU AGREE THAT THE COMPANY'S RATES SHOULD BE COMPARED SOLELY TO ITS NEIGHBORING ELECTRIC UTILITY?

A. No. Benchmarking utility rates and financial performance to a sampling of similarly situated utilities is a common practice. Indeed, in the current proceeding, Mr. Gorman compares the Company's requested ROE to a suite of peer utility holding companies. Table 1 compares the Company's current and proposed residential and small commercial customer charges to the various electric utilities operated by these holding companies. My analysis finds that the Company's current residential customer charge of $13.10 is higher than the average of these ROE peer companies. Likewise, while the Company's current general light and power ('GLP-1") customer charge of $16.00 is lower than the average of these companies, the Company's proposed GLP-1 customer charge rate of $21.00 is higher than the average customer charge of these ROE peer companies.

Q. DO THESE RESULTS INDICATE ANY PRESSING NEED TO INCREASE MONTHLY CUSTOMER CHARGE RATES?

A. No, the Company's existing customer charges are reasonably similar to those utilities operated by the utility holding companies included in the Company's ROE peer group. This builds on the findings I presented in my direct testimony that showed that the Company's current residential customer charge is the highest in the region, while its current GLP-1 customer charge is the second highest in the region.

V. CONCLUSIONS AND RECOMMENDATIONS

Q. HAVE YOUR ACOS RECOMMENDATIONS PRESENTED IN YOUR DIRECT TESTIMONY CHANGED AFTER REVIEWING PARTIES REBUTTAL TESTIMONIES?

A. No. I continue to find that Citizens' incorrect classification of secondary-voltage distribution plant skews the allocation of costs and revenue responsibilities away from larger customers and onto residential customers. I continue to recommend the Commission rely on the results of my alternative ACOS presented in my direct testimony as a fair and reasonable estimation of relative costs of service between Citizens' customer classes.

Q. HAVE YOUR REVENUE DISTRIBUTION RECOMMENDATIONS PRESENTED IN YOUR DIRECT TESTIMONY CHANGED AFTER REVIEWING THE COMPANY'S WITNESS GORMAN'S REBUTTAL TESTIMONY?

A. No. I continue to recommend the Commission adopt a more reasonable revenue distribution allocation method based on my alternative ACOS results that also limits the rate increase to the MBL customer class to 1.25 times the overall system average increase.

Q. HAVE YOUR RECOMMENDATIONS REGARDING THE COMPANY'S PROPOSED INCREASE IN CUSTOMER CHARGES CHANGED AFTER REVIEWING MR. GORMAN'S REBUTTAL TESTIMONY?

A. No. I continue to recommend the Commission reject Citizens' proposed increases in customer charges because they disproportionately impact low-income customers and reduce customer incentives to reduce usage, contrary to public goals of promoting energy efficiency. Furthermore, Citizens' existing residential and small commercial customer charges are already higher than the regional average of peer investor-owned utilities, and the proposed increase would make the charges the highest among peers. Finally, a correct analysis of customer-related costs from Citizens' ACOS finds that all residential

and commercial rate classes are currently recovering *all* customer-related costs through monthly customer charges.

Q. DOES THIS CONCLUDE YOUR SURREBUTTAL TESTIMONY?

A. Yes.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No. R-2025-3054394
	:	
Citizens' Electric Co. of Lewisburg, PA	:	

VERIFICATION

I, Michael W. Deupree, hereby state that the facts above set forth in my Surrebuttal Testimony, OCA Statement No. 3SR, are true and correct to the best of my knowledge, information, and belief and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa.C.S. § 4904 (relating to unsworn falsification to authorities).

DATED: August 28, 2025

Signature: /s/ Michael W. Deupree
Michael W. Deupree

Address: Acadian Consulting Group
5800 One Perkins Place Drive
Suite 5-F
Baton Rouge, LA 70808

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	Docket No.: R-2025-3054392
v.	:	
	:	
Wellsboro Electric Company	:	

SURREBUTTAL TESTIMONY

OF

Michael Deupree

On behalf of the

PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

OCA Statement 3SR

Date Served: August 28, 2025

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS?

A. My name is Michael W. Deupree. My business address is 5800 One Perkins Place Drive, Suite 5-F, Baton Rouge, Louisiana, 70808.

Q. HAVE YOU PREVIOUSLY FILED TESTIMONY IN THIS PROCEEDING?

A. Yes. I filed direct and rebuttal testimony in this proceeding on July 15, 2025, and August 13, 2025, respectively, on behalf of the Pennsylvania Office of Consumer Advocate ("OCA").

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to respond to elements of the rebuttal testimonies of Howard S. Gorman on behalf of Wellsboro Electric Company ("Wellsboro" or the "Company"), and Justin B. Farr on behalf of the Pennsylvania Office of Small Business Advocate ("OSBA"). Specifically, I will respond to Wellsboro and OSBA's discussion on the use of a zero-load analysis to classify a portion of electric distribution costs as customer related, and Wellsboro's response to my proposed revenue allocation and analysis of customer-related costs.

II. CLASSIFICATION OF ELECTRIC DISTRIBUTION COSTS

Q. PLEASE SUMMARIZE COMPANY WITNESS GORMAN'S RESPONSE TO YOUR CLASSIFICATION OF THE SECONDARY PORTION OF DISTRIBUTION PLANT ACCOUNTS 364-368.

A. Mr. Gorman argues that classification of the secondary portion of distribution plant accounts 364-368 as 100 percent demand-related is problematic on several levels. First, he disputes my assertion that zero-load analyses are meaningless due to reliance on the

theoretical construct of a system incapable of having load-carrying capabilities.[1] Second, he argues that my direct testimony ignores important findings by Professor Bonbright in his treatise on rate design.[2] Finally, Mr. Gorman disregards my empirical findings showing a lack of statistical correlation between changes in customer counts and distribution system investments as making no sense on a prima-facie basis.[3]

Q. PLEASE SUMMARIZE OSBA WITNESS FARR'S RESPONSE TO YOUR CLASSIFICATION OF THE SECONDARY PORTION OF DISTRIBUTION PLANT ACCOUNTS 364-368.

A. Mr. Farr asserts that the NARUC Manual references accounts 364-368 as containing both customer and demand-related components.[4]

Q. WHY DOES WELLSBORO WITNESS GORMAN ARGUE THAT ZERO-LOAD ANALYSES SERVE AS USEFUL TOOLS TO SEPARATE COSTS BETWEEN DEMAND-RELATED AND CUSTOMER-RELATED FUNCTIONS?

A. Mr. Gorman argues that my critiques about the classification of secondary distribution plant accounts represent "often used but misleading argument."[5] Specifically, Mr. Gorman notes that he acknowledges that his zero-load analysis and related Minimum Size System ("MSS") analyses are theoretical constructs, but he argues that this is not a valid reason to reject the results of such analyses.[6] Instead, Mr. Gorman argues that

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[1] Rebuttal Testimony of Howard S. Gorman at 8:14-17 and 9:8-12.

[2] *Id.* at 9:13-19.

[3] *Id.* at 10:1-4.

[4] Rebuttal Testimony of Justin B. Farr at 3:12 to 4:4.

[5] Rebuttal Testimony of Howard S. Gorman at 8:14.

[6] *Id.* at 8:14-16.

these analyses represent "useful tools," to separate costs between demand-related and customer-related functions, regardless of the fact that no such system would be constructed in reality.[7] Mr. Gorman notes as evidence that it would be possible to install transformers with ratings of 10.0 kVA for customers where this is sufficient to meet demand, and to install larger capacity transformers only where needed.[8]

Q. DO YOU AGREE WITH COMPANY WITNESS GORMAN'S ARGUMENTS ABOUT THE POTENTIAL VALIDITY OF ZERO-LOAD AND MSS ANALYSES?

A. No. Mr. Gorman appears to have misunderstood that my critique is that the theoretical nature of these analyses is an inherent flaw of the analyses. The conceptual purpose of a zero-load analysis is supposedly to identify the system costs that are associated with a hypothetical electric distribution system that serves all customers on its system as connections but which **cannot** serve customer loads (or "zero-load") and thus **cannot** serve these connected customers. This contradiction in purpose is why such a system would never exist, which furthermore creates inherent problems highlighted by Mr. Gorman's statement concerning transformer capacity. Mr. Gorman's zero-load analysis estimates a replacement cost for the Company's inventory of transformers that range in capabilities from 1.5 to 1500 kVA.[9] As Mr. Gorman acknowledges, these replacement transformers, even a minimum-size system, **would be sufficient** to meet many customers' demand requirements, a direct violation of the conceptual purpose of a

[7] *Id.* at 8:16-17.

[8] *Id.* at 9:1-4.

[9] Company's Response to Data Request I&E-RE-1-D Attachment A, D3.

zero-load analysis which is to estimate the costs of a hypothetical electric distribution system **that is not sufficient** to meet customers' demand requirements.

Q. HAS AUTHORITATIVE SOURCES COMMENTED ON THIS CONCERN ASSOCIATED WITH MSS ANALYSES?

A. Yes. As I referenced in my direct testimony, the National Association of Regulatory Utility Commissioners ("NARUC") Electric Cost Allocation Manual ("NARUC Manual") specifically recognizes this fundamental failing of zero-load analyses in its discussion noting that "… the analyst must be aware that the minimum-size distribution equipment has a certain load-carrying capability, **which can be viewed as a demand-related costs**."[10] Essentially, a direct reliance on replacement costs, as the Company has done in the current proceeding for line transformers, would **necessarily over-estimate** the customer-related portion of the equipment costs, even if one accepts the premise of a zero-load or MSS analysis.

Q. IS IT POSSIBLE TO ESTIMATE THE COST OF A ZERO-LOAD SYSTEM?

A. No. When done appropriately, a zero-load analysis would involve estimating the costs of an electric distribution system which cannot function as an electric distribution system. For example, a correct zero-load analysis would require the estimation of the cost of an 'electric line transformer' which cannot function as an electric line transformer – effectively an empty box. Even if one could estimate the costs of this farcical 'electric line transformer,' it would be impossible to verify these estimates with any degree of analytical rigor required in the setting of just and reasonable rates.

[10] Direct Testimony of Michael W. Deupree at 18:2-5, *emphasis added.*

Q. DOES THIS FLAW ALSO HOLD TRUE FOR MR. GORMAN'S ESTIMATION OF ZERO-LOAD COSTS ASSOCIATED WITH POLES, OVERHEAD AND UNDERGROUND CONDUCTORS?

A. Yes. Mr. Gorman's zero-load analysis does not include material costs in his analysis of the zero-load costs associated with secondary electric distribution poles, and overhead and underground conductors (i.e. lines), instead only estimating the labor, overhead, and vehicle costs associated with replacement. However, even this analysis does not truly estimate the costs of a zero-load replacement system as it assumes this replacement system would contain the same number of circuit miles as Wellsboro's current system which was designed with customer's load requirements in mind.[11] A true zero-load replacement system would certainly contain fewer circuit miles compared to Wellsboro's current system.

Q. DO YOU AGREE WITH MR. GORMAN'S CHARACTERIZATION OF PROFESSOR BONBRIGHT'S STATEMENTS ON CLASSIFYING MINIMUM-SIZED DISTRIBUTION SYSTEM COSTS AS CUSTOMER-RELATED?

A. No. Mr. Gorman selectively quotes Professor Bonbright's treatise on the issue out of context. Professor Bonbright's full quote for the record is provided below, and clearly shows his negative opinion on classifying minimum-sized distribution system costs as customer-related.

> While, for the reason just suggested, **the inclusion of the costs of a minimum-sized distribution system among the customer-related costs seems to us <u>clearly indefensible</u>**, its exclusion from the demand-related costs stands on much firmer ground. For this exclusion of minimum-sized

[11] Company's Response to Data Request I&E-RE-1-D Attachment A, D1.

> distribution system costs makes more plausible the assumption that the *remaining* cost of the secondary distribution system is a cost which varies continuously (and, perhaps, even more or less directly) with the maximum demand imposed on this system as measured by peak load.
>
> But if the hypothetical cost of a minimum-sized distribution system is properly excluded from the demand-related costs for the reason just given, while it is also denied a place among the customer costs for the reason stated previously, to which cost function does it then belong? **The only defensible answer, in our opinion, is that it belongs to none of them**. Instead, it should be recognized as a strictly unallocable portion of total costs. And this is the disposition that it would probably receive in an estimate of long-run marginal costs. But fully-distributed cost analysts dare not avail themselves of this solution, since they are the prisoners of their own assumption that "the sum of the parts equals the whole." They are therefore under impelling pressure to fudge their cost apportionments **by using the category of customer costs as a dumping ground for costs that they cannot plausibly impute to any of their other cost categories**.[12]

Q. WHY DOES PROFESSOR BONBRIGHT FIND THAT CLASSIFYING MINIMUM-SYSTEM COSTS AS CUSTOMER-RELATED "CLEARLY INDEFENSIBLE?"

A. Professor Bonbright notes the lack of empirical support in academic literature for a causal relationship between distribution system investments and changes in the number of customers on the system. A relationship, or rather lack thereof, which I showed in my direct testimony can also be seen when examining historic Wellsboro's distribution system investments.[13]

Q. WHAT IS WITNESS GORMAN'S RESPONSE TO YOUR EMPIRICAL ANALYSIS OF THE LACK OF A CAUSAL RELATIONSHIP BETWEEN ELECTRIC

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[12] James C. Bonbright, *et al.* Principles of Public Utility Rates. 1988 Edition. Arlington, VA: Public Utilities Reports, Inc., pp. 491-492; *emphasis added.*

[13] Direct Testimony of Michael W. Deupree at 20:8 to 21:8.

DISTRIBUTION SYSTEM INVESTMENTS AND CHANGES IN THE NUMBER OF CUSTOMERS ON THE SYSTEM?

A. Mr. Gorman dismisses the conclusion of my analysis showing little to no correlation between electric distribution system investments and changes in the number of customers on the system, as not making sense.[14] Mr. Gorman again appears to have misunderstood my critique by correctly noting that it must make investments in its distribution system even during years when it experiences decreases in customer counts.[15] This is because a sizable portion of most electric distribution system investments are non-growth related, but instead associated with public policy such as improving/maintaining system reliability.[16] However, this recognition of the lack of a direct causal relationship between growth in customer counts and electric distribution investments undermines the very premise of attempting to classify a portion of such investment costs as customer-related, as Professor Bonbright observed decades ago, and which Mr. Gorman appears to agree with here, at least to an extent.

Q. WHAT IS YOUR RESPONSE TO OSBA WITNESS FARR'S CLAIMS THAT THE NARUC MANUAL PROVIDES THAT SECONDARY ELECTRIC DISTRIBUTION PLANT ASSETS CONTAIN BOTH DEMAND AND CUSTOMER COMPONENTS?

A. Mr. Farr's assertion is inaccurate as to the NARUC Manual because the NARUC Manual does not provide that secondary electric distribution plant assets contain both demand and customer components. Rather, as noted in the NARUC Manual preface, the

[14] Rebuttal Testimony of Howard S. Gorman at 10:1-4.

[15] *Id.* at 10:4-5.

[16] *See*, Rebuttal Testimony of Howard S. Gorman at 10:5-10.

manual is not intended to advocate for any one particular cost allocation method, but rather discuss all methods that are currently used.[17] Indeed, the NARUC Manual references the controversial classification of substations, poles, transformers, and conductors between demand and customer classifications. Contrast with the less controversial classification of distribution plant accounts 369-373 covering services, meters, street lights, and equipment installed on customer premises, which are generally recognized as fully customer-related and whose costs are either directly assigned to relevant customers or otherwise allocated based on a measure of customer accounts. The NARUC Manual provides as follows:

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Q. DOES WELLSBORO WITNESS GORMAN SUPPORT YOUR PROPOSED REVENUE ALLOCATIONS?

A. No. Mr. Gorman asserts that my proposed revenue allocations are not supported because they are based on what he asserts is my faulty alternative ACOS study, which he asserts fails to recognize any customer component to the secondary electric distribution system, and therefore should be rejected.[19]

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[17] Electric Utility Cost Allocation Manual (January 1992), NARUC, p. ii.

[18] *Id.* at pp. 95-96; *emphasis added.*

[19] Rebuttal Testimony of Howard S. Gorman at 12:3-7.

Q. HOW DO YOU RESPOND TO MR. GORMAN?

A. My alternative ACOS presented in my direct testimony is not faulty and provides a fair and reasonable estimation of relative costs of service between Wellsboro's customer classes. As I summarize in my direct testimony, Mr. Gorman's inappropriate classification of costs associated with secondary-voltage distribution plant accounts 364-368 skews the allocation of costs and revenue responsibilities away from larger customers and onto residential customers and small commercial customers.[20] MSS and related zero-load analyses depend on deeply flawed premises that have been criticized on theoretical and empirical grounds for decades.[21] As I showed in my direct testimony, there is no statistically significant relationship between changes in average number of customers on Citizens' system and the utility's investment in distribution plant accounts 364-368, highlighting this empirical criticism.[22] It is important that the just and reasonable rates be based on an ACOS that corrects for this flaw.

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[20] Direct Testimony of Michael W. Deupree at 23:14-20.

[21] *See*, *Id.* at 18:16 to 20:7.

[22] *Id.* at 20:8 to 21:7.

flaw in his computation of customer-related costs.[23] Second, Mr. Gorman disagrees with my regional peer group used to compare the Company's rates.[24] Finally, Mr. Gorman disagrees with my concerns regarding the negative impacts of higher customer charges on energy conservation, noting that the Company's proposed customer charge recovers only 28.7 percent of monthly distribution charges for the typical residential customer.[25]

Q. HOW DO YOU RESPOND TO MR. GORMAN'S ARGUMENT THAT YOU DID NOT IDENTIFY ANY SIGNIFICANT FLAW IN THE COMPANY'S COMPUTATION OF CUSTOMER-RELATED COSTS?

A. First, Mr. Gorman's analysis of customer-related costs is flawed because it does include costs associated with line transformers (FERC Account 368). However, ignoring this element, Mr. Gorman's analysis is also flawed in that it assumes the Company's requested rate of return on rate base ("ROR") of 8.18 percent in calculating the required return on customer-related rate base, as I discussed in my rebuttal testimony.[26] The Company's requested ROR is dependent on the Commission's finding of a just and reasonable ROR at the end of this proceeding and therefore is unknown at the current juncture. I therefore based my analysis of customer-related costs on the Company's estimated ROR under current rates of 1.46 percent.[27]

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[23] *Id.* at 12:14-20.

[24] *Id.* at 12:23 to 13:2.

[25] *Id.* at 13:7-11.

[26] Rebuttal Testimony of Michael W. Deupree at 2:12-15.

[27] *Id.* at 2:17-19.

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Entergy Arkansas	AR	8.40	24.25
Southwestern Electric Power Co.	AR	11.97	14.28
Arizona Public Service Co.	AZ	13.93	38.58
Southern California Edison	CA	10.52	14.24
Public Service Company of Colorado	CO	12.20	20.40
Duke Energy Florida	FL	13.83	17.85
Georgia Power	GA	14.00	36.00
Interstate Power and Light Co.	IA	15.50	23.00
Idaho Power Company	ID	15.00	25.00
Ameren Illinois Co.	IL	6.77	18.15
Duke Energy Indiana	IN	13.70	13.91
Indiana Michigan Power Co.	IN	15.00	29.00
Evergy Kansas Central	KS	14.25	25.29
Evergy Kansas Metro	KS	14.25	17.70
Duke Energy Kentucky	KY	16.00	15.00
Kentucky Power Co.	KY	20.00	28.00
Entergy Louisiana - Gulf States	LA	10.00	13.39
Entergy Louisiana	LA	10.00	9.82
Entergy New Orleans	LA	8.07	0.00
Southwestern Electric Power Co.	LA	7.43	26.17
Northern States Power Co.	MI	9.00	11.50
Indiana Michigan Power Co.	MI	7.58	23.30
Northern States Power Co.	MN	6.00	6.00
Union Electric Co.	MO	9.00	13.46
Evergy Missouri Metro	MO	12.00	18.69
Evergy Missouri West	MO	12.90	10.00
Mississippi Power	MS	48.67	51.71
Entergy Mississippi	MS	31.82	53.10
NorthWestern Energy	MT	4.20	22.05
Duke Energy Carolinas	NC	14.00	21.00
Duke Energy Progress	NC	14.00	22.00
Northern States Power Co.	ND	15.00	16.75
PNM	NM	10.94	22.85
Southwestern Public Service Co.	NM	11.20	21.50
Duke Energy Ohio	OH	8.00	12.00
Ohio Power Company	OH	10.00	9.40
Oklahoma Gas and Electric Co.	OK	13.00	50.95
Public Service Company of Oklahoma	OK	17.00	58.63
Idaho Power Company	OR	10.00	9.50
Portland General Electric Co.	OR	13.00	24.00
Duke Energy Carolinas	SC	11.96	13.50
Duke Energy Progress	SC	11.78	14.00
NorthWestern Energy	SD	7.00	12.00
Northern States Power Co.	SD	8.30	9.05
Kingsport Power Co.	TN	16.43	22.03
Texas-New Mexico Power Co.	TX	7.85	24.56
Xcel Energy	TX	12.45	16.00
Entergy Texas	TX	14.00	21.94
Southwestern Electric Power Co.	TX	9.42	13.06
Appalachian Power Co.	VA	7.96	9.88
Wisconsin Power and Light Co.	WI	15.00	17.00
Northern States Power Co.	WI	15.00	15.00
Appalachian Power Co. & Wheeling Power Co.	WV	12.50	15.00
Peer Group Average		**$ 12.76**	**$ 20.75**

Q. DO YOU AGREE THAT THE COMPANY'S RATES SHOULD BE COMPARED SOLELY TO ITS NEIGHBORING ELECTRIC UTILITY?

A. No. Benchmarking utility rates and financial performance to a sampling of similarly situated utilities is a common practice. Indeed, in the current proceeding, Mr. Gorman compares the Company's requested ROE to a suite of peer utility holding companies. Table 1 compares the Company's current and proposed residential and small commercial customer charges to the various electric utilities operated by these holding companies. My analysis finds that the Company's current residential customer charge of $12.00 is only slightly below the average of these ROE peer companies.

Q. DO THESE RESULTS INDICATE ANY PRESSING NEED TO INCREASE MONTHLY CUSTOMER CHARGE RATES?

A. No, the Company's existing customer charges are reasonably similar to those utilities operated by the utility holding companies included in the Company's ROE peer group. This builds on the findings I presented in my direct testimony that showed that the Company's current residential customer charge is higher than the regional average, while its proposed non-residential service ("NRS") and non-residential heating ("NRH") customer charge of $16.50 would be higher than the regional average.

V. CONCLUSIONS AND RECOMMENDATIONS

Q. HAVE YOUR ACOS RECOMMENDATIONS PRESENTED IN YOUR DIRECT TESTIMONY CHANGED AFTER REVIEWING PARTIES REBUTTAL TESTIMONIES?

A. No. I continue to find that Wellsboro's incorrect classification of secondary-voltage distribution plant skews the allocation of costs and revenue responsibilities away from larger customers and onto residential customers. I continue to recommend the

Commission rely on the results of my alternative ACOS presented in my direct testimony as a fair and reasonable estimation of relative costs of service between Wellsboro's customer classes.

Q. HAVE YOUR REVENUE DISTRIBUTION RECOMMENDATIONS PRESENTED IN YOUR DIRECT TESTIMONY CHANGED AFTER REVIEWING COMPANY WITNESS GORMAN'S REBUTTAL TESTIMONY?

A. No. I continue to recommend the Commission adopt a more reasonable revenue distribution allocation method based on my alternative ACOS results that also limits rate increases to the NRH, commercial service-heating ("CSH"), and residential service-all electric ("RSAE") customer classes to 1.25 times the overall system average increase.

Q. HAVE YOUR RECOMMENDATIONS REGARDING THE COMPANY'S PROPOSED INCREASE IN CUSTOMER CHARGES CHANGED AFTER REVIEWING MR. GORMAN'S REBUTTAL TESTIMONY?

A. No. I continue to recommend the Commission reject Wellsboro's proposed increases in customer charges because they disproportionately impact low-income customers and reduce customer incentives to reduce usage, contrary to public goals of promoting energy efficiency. Furthermore, Wellsboro's existing residential customer charge is the third highest in the region and the proposed increase would make the charge the highest among regional peer investor-owned utilities. Finally, a correct analysis of customer-related costs from Wellsboro's ACOS finds that all residential and commercial rate classes are currently recovering *nearly all* customer-related costs through monthly customer charges.

Q. DO YOU HAVE AN ALTERANTIVE RECOMMENDATION IF THE COMMISSION DECIDES AN INCREASE IN MONTHLY CUSTOMER CHARGES IS WARRANTED?

A. Yes. I still recommend that the Commission limit its increase in Wellsboro monthly customer charge to only that required to bring the Company's customer charges in line with Citizens' Electric Company.

Q. DOES THIS CONCLUDE YOUR SURREBUTTAL TESTIMONY?

A. Yes.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No. R-2025-3054392
	:	
Wellsboro Electric Company	:	

VERIFICATION

I, Michael W. Deupree, hereby state that the facts above set forth in my Surrebuttal Testimony, OCA Statement No. 3SR, are true and correct to the best of my knowledge, information, and belief and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa.C.S. § 4904 (relating to unsworn falsification to authorities).

DATED: August 28, 2025

Signature: /s/ Michael W. Deupree
Michael W. Deupree

Address: Acadian Consulting Group
5800 One Perkins Place Drive
Suite 5-F
Baton Rouge, LA 70808

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	Docket No.: R-2025-3054393
v.	:	
	:	
Valley Energy, Inc.	:	

SURREBUTTAL TESTIMONY

OF

Michael Deupree

On behalf of the

PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

OCA Statement 3R

Date Served: August 28, 2025

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS?

A. My name is Michael W. Deupree. My business address is 5800 One Perkins Place Drive, Suite 5-F, Baton Rouge, Louisiana, 70808.

Q. HAVE YOU PREVIOUSLY FILED TESTIMONY IN THIS PROCEEDING?

A. Yes. I filed direct and rebuttal testimony in this proceeding on July 15, 2025, and August 13, 2025, respectively, on behalf of the Pennsylvania Office of Consumer Advocate ("OCA").

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to respond to elements of the rebuttal testimonies of Howard S. Gorman on behalf of Valley Energy, Inc. ("Valley" or the "Company"). Specifically, I will respond to Valley's discussion of appropriate customer charge.

II. CUSTOMER CHARGE

Q. DID MR. GORMAN AGREE WITH YOUR PROPOSAL TO REJECT ANY PROPOSED INCREASES IN EXISTING CUSTOMER CHARGES?

A. No. Mr. Gorman disagrees with my arguments regarding customer charges for multiple reasons. First, he argues that an allocated cost of service ("ACOS") study is not necessary to evaluate the appropriateness of Valley's proposed customer charges.[1] Second, he disagrees with my conclusion that the Company's proposed customer charge is inconsistent with its regional peers.[2] Finally, Mr. Gorman disagrees with my concerns

[1] Rebuttal Testimony of Howard S. Gorman at 8:14-18.

[2] *Id.* at 8:21 to 9:8.

regarding the negative impacts of higher customer charges on energy conservation, noting that inefficient pricing and under-recovery of costs lead to more frequent rate cases.[3]

Q. DO YOU AGREE WITH MR. GORMAN THAT AN ACOS STUDY IS NOT NECESSARY TO EVALUATE THE APPROPRIATENESS OF VALLEY'S CUSTOMER CHARGES?

A. No. It is a major deficiency that Mr. Gorman's proposal is not supported by any cost-based analysis in the current proceeding or any known prior rate case proceeding. This is especially true since the Company's current residential and commercial customer charges are near the average of other similarly situated natural gas distribution utilities in the region. It is appropriate to reject any proposed increase in current customer charge until such an increase can be supported by an analysis of ACOS.

III. CONCLUSIONS AND RECOMMENDATIONS

Q. HAVE YOUR RECOMMENDATIONS REGARDING THE COMPANY'S PROPOSED INCREASE IN CUSTOMER CHARGES CHANGED AFTER REVIEWING THE COMPANY'S REBUTTAL TESTIMONY?

A. No. I continue to recommend the Commission reject Valley's proposed increases in customer charges because the Company has no cost basis for its proposed customer charges. The Company's current residential and commercial customer charges are similarly near the average of other similarly situated natural gas distribution utilities in the region. Finally, the proposed increase would disproportionately impact low-income

[3] *Id.* at 9:10-16.

customers and reduce customer incentives to reduce usage, contrary to public goals of promoting energy efficiency.

Q. DO YOU HAVE AN ALTERNATIVE RECOMMENDATION IF THE COMMISSION DECIDES AN INCREASE IN MONTHLY CUSTOMER CHARGES IS WARRANTED?

A. Yes. If the Commission determines that increases in the Company's customer charge are warranted, I still recommend that the Commission cap these increases to no more than the overall system average increase. This will prevent Company rates from becoming more reliant on fixed monthly charges relative to volumetric charges as a result of this proceeding.

Q. DOES THIS CONCLUDE YOUR SURREBUTTAL TESTIMONY?

A. Yes.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No. R-2025-3054393
	:	
Valley Energy, Inc.	:	
	:	

VERIFICATION

I, Michael Deupree, hereby state that the facts above set forth in my Surrebuttal Testimony, OCA Statement No. 3SR, are true and correct to the best of my knowledge, information, and belief and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa.C.S. § 4904 (relating to unsworn falsification to authorities).

DATED: August 28, 2025

Signature: */s/ Michael Deupree*
Michael Deupree

Address: Acadian Consulting Group
5800 One Perkins Place Drive
Suite 5-F
Baton Rouge, LA 70808

OCA STATEMENT 4SR

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission

v. **:** **Docket No. R-2025-3054393**

Valley Energy, Inc.

SURREBUTTAL TESTIMONY OF

LeeAnn Wise
ON BEHALF OF THE
OFFICE OF CONSUMER ADVOCATE

August 28, 2025

Q: PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A: LeeAnn Wise. 555 Walnut Street, Forum Place 5th Floor, Harrisburg Pennsylvania 17101.

Q: ARE YOU THE SAME LEEANN WISE WHO PREVIOUSLY FILED DIRECT TESTIMONY IN THIS PROCEEDING?

A: Yes, I am.

Q: WHAT IS THE PURPOSE OF YOUR SURREBUTTAL TESTIMONY?

A: I will respond to certain relevant comments in Company witnesses Ms. Beale and Mr. Rogers' rebuttal testimony related to my direct testimony. Both have offered numerous critiques of my testimony that I disagree with and wish to respond.

Q: DO YOU AGREE WITH MS. BEALE'S COMMENTS REGARDING FORMAL POLICIES AND PROCEDURE ON SECURITY DEPOSITIS?

No. While I understand the Company's perspective that its small staff and informal training practices may reduce the perceived need for formal policies and procedures, I continue to emphasize that written policies for refunding security deposits are essential—regardless of company size.

I acknowledge Mrs. Beale's statement that the Company's Customer Service Representative are thoroughly trained.[1] I respectfully ask, "What defines this training"? Is it side by side mentoring, team leader training, or some other format?

[1] Valley Statement No. 5R

Formal procedures promote consistency, transparency, and accountability. Even in small organizations, the absence of standardized processes increases the risk of misunderstandings, inconsistent application, and reliance on individual interpretation. Informal, experience-based training can vary significantly between employees, particularly in the event of staff turnover. Written policies help ensure clarity and uniformity in practice, regardless of staff size, skill level, or tenure. Small companies may benefit even more from having formal documentation, since reliance on a single employee for specific knowledge creates operational risk if that individual departs.

Q. DO YOU AGREE WITH MS. BEALE'S COMMENTS ON REFUNDING SECURITY DEPOSITS?

A. No. I continue to suggest that the Company provide the option for customers as to how they wish to receive a refund of security deposits. Mrs. Beale suggests that providing the option would involve additional administrative tasks and would take more time to return the deposit because the Company would need to wait for a customer's decision before proceeding. Ultimately, as long as the customers pay their current and future bills, the effect is the same.[2]

I am not suggesting the Company wait for the customer's decision before issuing a refund. I am suggesting if a customer requests their refund, they should have the option of receiving the cash back. Low-income customers face financial struggles

[2] Valley Statement No. 5R

daily and therefore may need these funds to satisfy immediate non-utility needs. Applying credit to the customer's account can inadvertently limit their ability to manage their money.

In today's economy, many households continue to face increasing financial pressures, providing flexibility would echo the Company's commitment to putting the customers' needs first.

Q: DO YOU AGREE WITH MS. BEALE'S STATEMENT THAT PAYMENT PLAN METRICS ARE NOT APPROPRIATE?

A: No, I continue to believe that implementing formal policies and establishing clear performance metrics for payment plans, ensuring transparency in verifying low-income eligibility, are both appropriate and necessary.

The absence of documented policies and objective metrics introduces the risk of inconsistent handling of payment arrangements. While informal training and individualized case-by-case decisions may seem sufficient for a small team, standardized procedures are essential to ensure equity, accountability, and transparency, particularly for customers facing financial hardships. A well-defined framework protects the interests of both the Company and its customers.

My recommendation to evaluate the effectiveness of the Company's payment plans was not intended to be criticism, nor did I intend to suggest that all payment plans are broken due to lack of payment. Rather, it reflects a recognized utility challenge: unaffordable or poorly aligned payment agreements often lead to broken arrangements. Without properly tracking success rates for identifying underlying

reasons why customers default, it becomes difficult to improve plan structure or anticipate disconnections.

Certainly, service disconnections sometimes become unavoidable. These situations underscore the need for payment plans to be realistic, affordable, and sustainable.

Evaluating why plans fail can yield valuable insights that lead to better strategies and ultimately support customer retention.

In conclusion, I stand by my recommendation that the Company adopt formal policies, define success metrics, and implement evaluation procedures. Without structured oversight and measurable standards, can lead to concerns about the Company's ability to manage payment plan strategies in a fair and effective manner. These actions will not only improve customer outcomes and reduce terminations but also enhance customer satisfaction.

Q: DO YOU AGREE WITH MR. ROGERS STATEMENTS REGARDING THE ELIMINATION OF THE $3.95 CREDIT/DEBIT CARD FEES?

A: No. Assessing a $3.95 processing fee for credit and debit card payments is not reasonable nor is it in public interest. This fee unfairly penalizes customers who choose – or are often forced – to use a more efficient and modern method of payment.

The Company states the customer currently has many options to pay, which are much cheaper on a transactional basis compared to the current fee associated with

debit or credit card payments.[3] They fail to acknowledge processing these forms of payment carry administrative and operational expenses which are included in revenue requirement.

There is a fundamental contradiction in how payment processing costs are treated. The administrative costs of handling checks, and cash are included in the utility rate base – and therefore shared among all customers. However, the credit/debit card fee is being passed only to customers using that method, creating an unfair and discriminatory issue.

If the principle of cost causation is to be applied consistently, then card processing fees – like other administrative payment costs – should be treated as part of the utility's cost of doing business, not an add-on fee to customers. Customers choosing a secure, fast, and modern method of payment should not be penalized.

The Company's statement that customers using credit cards to receive rewards or "perks" is irrelevant. In many cases, the fee far exceeds any reward value the card holder may receive. Any "perk" a customer may receive does not justify charging a $3.95 fee. Most importantly, many customers use credit cards out of necessity, not to earn points, but to avoid late payments and or possible service disconnections.

Although I recognize there are utilities that pass along service fees onto their customers, it should also be noted utilities have recognized the inequity and inefficiency of these charges and have moved to eliminate them. For example:

[3] Valley Statement No. 4R

- Columbia Gas of PA. No fees apply to residential customers for credit/debit/Pay Pay/Venmo one-time card payments.[4]
- Pennsylvania American Water eliminated its $1.95 fee for credit card payments in 2023 (PA PUC Docket No. R-2022-3031672).[5]
- Pittsburgh Water and Sewer Authority (PWSA) similarly removed credit card convenience fees to enhance accessibility and reduce barriers to payment (PWSA Customer Service Update, 2022).[6]

Q. DO YOU HAVE ANY COMMENTS ON THE COMPANY'S CONCERN WITH INCREASED CREDIT CARD USAGE ON FUTURE RATE CASES?

Yes, I would agree that the removal of the $3.95 represents the possibility of increased usage of credit/debit cards. However, these processing fees are a small part of the Company's overall operating expenses. The Company has not provided any evidence that increased usage of credit card payments would outweigh the benefits to customers or significantly impact on its revenue requirement which already includes administrative expenses.

As I stated previously, processing fees would reduce other operation expenses such as check processing fees, reduction in posting of payments, reduced past due balances, and collection costs. It is important to weigh both the cost increase along

[4] http://www.columbiagaspa.com/search-results#/?term=payment%20fees

[5] PA PUC Docket No. R-2022-303167

[6] https://www.pgh2o.com/residential-commercial-customers/account-billing-info/update-contact-information

with the reduction of administrative costs and the elimination of the processing fee brings.

There are several utilities in Pennsylvania and neighboring states who have eliminated these fees without experiencing destabilizing costs or large rate impacts to their customers. The fee is unfair and severely burdens low-income customers who rely on credit cards to pay their bills and therefore should be eliminated. For these reasons, I continue to support the elimination of the $3.95 processing fees.

Q: DOES THIS CONCLUDE YOUR SURREBUTTAL TESTIMONY?

A: Yes.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No. R-2025-3054393
	:	
Valley Energy, Inc.	:	
	:	

VERIFICATION

I, LeeAnn Wise, hereby state that the facts above set forth in my Surrebuttal Testimony, OCA Statement No. 4SR, are true and correct to the best of my knowledge, information, and belief and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa.C.S. § 4904 (relating to unsworn falsification to authorities).

DATED: August 28, 2025

Signature: */s/ LeeAnn Wise*
LeeAnn Wise

Address: Office of Consumer Advocate
555 Walnut Street
Forum Place, 5th Floor
Harrisburg, PA 17101

OCA STATEMENT 4SR

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission

v. **:** **Docket No. R-2025-3054394**

Citizens' Electric Company

SURREBUTTAL TESTIMONY OF

LeeAnn Wise
ON BEHALF OF THE
OFFICE OF CONSUMER ADVOCATE

August 28, 2025

Q: PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A: LeeAnn Wise. 555 Walnut Street, Forum Place 5th Floor, Harrisburg Pennsylvania 17101.

Q: ARE YOU THE SAME LEEANN WISE WHO PREVIOUSLY FILED DIRECT TESTIMONY IN THIS PROCEEDING?

A: Yes, I am.

Q: WHAT IS THE PURPOSE OF YOUR SURREBUTTAL TESTIMONY?

A: I will respond to Company witnesses Mr. Johnson and Ms. Stauder's rebuttal testimony to my direct testimony. Both Mr. Johnson and Ms. Stauder disagree with my findings on the topics of evaluating the effectiveness of payment plans, establishing procedures for handling security deposits, and eliminating credit card fees. I disagree with their critiques and will use this opportunity in surrebuttal testimony to explain why.

Q: DO YOU AGREE WITH MR. JOHNSON'S COMMENT RELATED TO PAYMENT PLANS?

A: No. While Mr. Johnson indicates that the Company follows general billing and collection practices, he does not directly address the specific concern raised in my testimony regarding the effectiveness of payment plans. Actively managing customer accounts is not equivalent to evaluating the success of payment agreements—such as tracking repeat arrangements, agreement completions versus defaults, or reductions in arrearages over time.

Without defined performance metrics, the Company cannot determine whether its payment plans meet customers' needs or are leading to improved financial outcomes. Simply offering payment arrangements is not enough; the Company must also assess whether those arrangements are successful and sustainable on a customer-by-customer basis.

Evaluating the outcomes of payment agreements does not need to be complex. In fact, the relatively small number of agreements currently in place makes such an evaluation more manageable. Without specific metrics, Citizens cannot meaningfully assess the effectiveness of its payment plans or identify areas where improvements are needed.

Financially responsible utilities do more than manage accounts receivable—they measure performance of activity to ensure their strategies are effective, sustainable, and serve the best interests of both the customer and the Company.

Q: DO YOU AGREE WITH MR. JOHNSON'S COMMENTS REGARDING FORMAL POLICIES AND PROCEDURE ON SECURITY DEPOSITIS?

No. While I understand the Company's perspective that its small staff and informal training practices may reduce the perceived need for formal policies and procedures, I continue to emphasize that written policies for refunding security deposits are essential, regardless of company size.

Formal procedures promote consistency, transparency, and accountability. Even in small organizations, the absence of standardized processes increases the risk of misunderstandings, inconsistent application, and reliance on individual

interpretation. Informal, experience-based training can vary significantly between employees, particularly in the event of turnover. Written policies help ensure clarity and uniformity in practice, regardless of staff size, skill level, or tenure. In fact, I would argue that small companies can benefit most from having formal documentation, since reliance on a single employee for specific knowledge creates operational risk if that employee were to depart the organization.

In my direct testimony, I acknowledge that the Company currently verifies income prior to assessing a security deposit. However, the Company also admits that it lacks a formal policy outlining this process. Without such documentation, there is no assurance that the Company is consistently identifying and exempting all qualified low-income applicants. While there is no statute mandating written procedures, having formal written policies can help ensure employees are complying with Commission regulations under 52 Pa. Code § 56.32 and meeting the quality-of-service standards mandated by statute at 66 Pa. C.S. § 1501.

For these reasons, I continue to recommend the Company implement formal written policies and procedures relating to accessing a security deposit.

Q: DO YOU AGREE WITH MR. JOHNSON'S STATEMENT REGARDING PAYMENT PLANS?

A: No. As I have previously acknowledged, I understand and respect the Company's small size. However, I continue to believe that implementing formal policies, establishing clear performance metrics for payment plans, and ensuring transparency in verifying low-income eligibility are both appropriate and necessary.

The absence of documented policies and objective metrics introduces the risk of inconsistent handling of payment arrangements. While informal training and individualized case-by-case decisions may seem sufficient for a small team, standardized procedures are essential to ensure equity, accountability, and transparency, particularly for customers facing financial hardships. A well-defined framework protects the interests of both the Company and its customers.

My recommendation to evaluate the effectiveness of the Company's payment plans was not intended to be criticism, nor did I intend to suggest that all payment plans are broken due to lack of payment. Rather, it reflects a recognized utility challenge: unaffordable or poorly aligned payment agreements often lead to broken arrangements. Without properly tracking success rates for identifying underlying reasons why customers default, it becomes difficult to improve plan structure or anticipate disconnections.

Certainly, service disconnections sometimes become unavoidable. These situations underscore the need for payment plans to be realistic, affordable, and sustainable. Evaluating why plans fail can yield valuable insights that lead to better strategies and ultimately support customer retention.

In conclusion, I stand by my recommendation that the Company adopt formal policies, define success metrics, and implement evaluation procedures. These actions will not only improve customer outcomes and reduce terminations but also enhance customer satisfaction.

Q: DO YOU AGREE WITH MS. STAUDER'S STATEMENTS REGARDING THE ELIMINATION OF THE $3.95 CREDIT/DEBIT CARD FEES?

A: No. Assessing a $3.95 processing fee for credit and debit card payments of utility bills is not reasonable nor is it in public interest. This fee unfairly penalizes customers who choose – or are often forced – to use a more efficient and modern method of payment.

While the Company argues that processing credit or debit card payments through a third-party vendor results in costs, it also downplays the true and total cost of processing cash and check payments that also carry administrative and operational expenses. The Company estimates a cost of $0.25 per transaction[1] to process a cash or check transaction, assuming 30 seconds or less per transaction at $30 per hour. However, they do not account for staff time to open mail, manually match checks with account numbers, input payments into the billing system, totaling cash/check amounts, preparing deposits, traveling to the bank, and updating account balances. Contrast with credit/debit card payments, which are processed electronically, immediately verified, and require no physical handling, deposit preparation, or travel. Credit/debit card payments also eliminate bounced check risk and reduce bad debit collection activities.

There is a fundamental contradiction in how payment processing costs are treated. The administrative costs of handling checks, and cash are included in the utility

[1] Citizens' Statement No. 5R

revenue requirement – and therefore shared among all customers. However, the credit/debit card fee is being passed only to customers using that method, creating an unfair and discriminatory issue.

If the principle of cost causation is to be applied consistently, then card processing fees – like other administrative payment costs – should be treated as part of the utility's cost of doing business, not an add-on fee imposed only on certain customers. Customers choosing a secure, fast, and modern method of payment should not be penalized.

The Company's statement that customers using credit cards to receive rewards or "perks" is irrelevant. In many cases, the fee far exceeds any reward value the card holder may receive. Any "perk" a customer may receive does not justify charging a $3.95 fee. Most importantly, many customers use credit cards out of necessity, not to earn points. For example, avoiding late payments and or possible service disconnections.

Although I recognize there are utilities that pass along service fees onto their customers, it should also be noted utilities have recognized the inequity and inefficiency of these charges and have moved to eliminate them. For example:

- Columbia Gas of PA has no fees apply to residential customers for credit/debit/Pay Pay/Venmo one-time card payments.[2]

[2] http://www.columbiagaspa.com/search-results#/?term=payment%20fees

- Pennsylvania American Water eliminated its $1.95 fee for credit card payments in 2023 (PA PUC Docket No. R-2022-3031672).[3]
- Pittsburgh Water and Sewer Authority (PWSA) similarly removed credit card convenience fees to enhance accessibility and reduce barriers to payment (PWSA Customer Service Update, 2022).[4]

Q. **DO YOU HAVE ANY COMMENTS ON THE COMPANY'S CONCERN WITH INCREASED CREDIT CARD USAGE ON FUTURE RATE CASES?**

Yes, I would agree that the removal of the $3.95 represents the possibility of increased usage of credit/debit cards. However, these processing fees are a small part of the Company's overall operating expenses. The Company has not provided any evidence that increased usage of credit card payments would outweigh the benefits to customers or significantly impact on their revenue requirement which already includes administrative expenses.

As I stated previously, processing fees would reduce other operation expenses such as check processing fees, reduction in posting of payments, reduced past due balances, and collection costs. It is important to weigh both the cost increase along with the reduction of administrative costs and the elimination of the processing fee brings.

There are several utilities in Pennsylvania and neighboring states who have eliminated these fees without experiencing destabilizing costs or large rate impacts

[3] PA PUC Docket No. R-2022-3031672

[4] https://www.pgh2o.com/residential-commercial-customers/account-billing-info/update-contact-information

to their customers. The fee is unfair and severely burdens low-income customers who rely on credit cards to pay their bills and therefore should be eliminated. For these reasons, I continue to support the elimination of the $3.95 processing fees.

Q: DOES THIS CONCLUDE YOUR SURREBUTTAL TESTIMONY?

A: Yes.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No. R-2025-3054394
	:	
Citizens' Electric Co. of Lewisburg, PA	:	

VERIFICATION

I, LeeAnn Wise, hereby state that the facts above set forth in my Surrebuttal Testimony, OCA Statement No. 4SR, are true and correct to the best of my knowledge, information, and belief and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa.C.S. § 4904 (relating to unsworn falsification to authorities).

DATED: August 28, 2025

Signature: */s/ LeeAnn Wise*
LeeAnn Wise

Address: Office of Consumer Advocate
555 Walnut Street
Harrisburg, PA 17101

OCA STATEMENT 4SR

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission		
v.	**:**	**Docket No. R-2025-3054392**
Wellsboro Electric Company		

SURREBUTTAL TESTIMONY OF

LeeAnn Wise
ON BEHALF OF THE
OFFICE OF CONSUMER ADVOCATE

August 28, 2025

Q: PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A: LeeAnn Wise. 555 Walnut Street, Forum Place 5th Floor, Harrisburg Pennsylvania 17101.

Q: ARE YOU THE SAME LEEANN WISE WHO PREVIOUSLY FILED DIRECT TESTIMONY IN THIS PROCEEDING?

A: Yes, I am.

Q: WHAT IS THE PURPOSE OF YOUR SURREBUTTAL TESTIMONY?

A: I will respond to Company witness Mr. Farnsworth's rebuttal testimony as it relates to my direct testimony. Mr. Farnsworth disagrees with my findings on the topics of evaluating the effectiveness of payment plans, establishing procedures for handling security deposits, and eliminating credit card fees. I disagree with their critiques and will use this opportunity in surrebuttal testimony to explain why.

Q: DO YOU AGREE WITH MR. FARNSWORTH'S COMMENTS ON PAYMENT PLANS?

A: No. I would first like to clarify that my review of Wellsboro's practices is not based on a misunderstanding of regulatory requirements, nor am I disputing the experience and knowledge of the Company's employees. Rather, it is a valid and necessary analysis of the Company's lack of formal documentation and measurable performance metrics related to its payment plans.

My testimony emphasized the absence of such metrics as a barrier to evaluating the effectiveness of these plans. Without data on the outcomes of current payment arrangements, the Company cannot determine what is working or where

improvements are needed. This is not speculative—across the utility industry it is well-established that unaffordable or poorly structured payment plans often lead to customer defaults. Without measuring success rates or understanding why customers fail to meet their agreements, it is difficult to improve structures or identify breakdowns that can lead to disconnections.

These metrics are not just tools for internal improvement, they are also necessary to ensure transparency, accountability, and equitable treatment of customers, particularly in regulatory proceedings. While there is no legal mandate requiring utilities to maintain written policies or specific metrics, having formal written policies can help ensure employees are complying with Commission regulations.

Furthermore, Mr. Farnsworth's reference to delinquency rates of 14–17% lacks the necessary context to assess the success of the Company's payment plans. These figures do not address the core issue I raised: whether the payment plans are effectively helping customers avoid disconnecting and maintain service. Delinquency percentages alone do not reflect how accessible or sustainable the payment plans are.

I recommend that the Company should be tracking, at minimum, the following:

- What percentage of payment arrangements are completed successfully?
- How many customers default shortly after enrollment?
- How many payment arrangements were denied?
- Are there disparities in outcomes among different customer groups?

In conclusion, while the Company rightly emphasizes its local presence and the dedication of its staff, these strengths should be supported—not to replace structured policies, performance metrics, and evaluative practices. These tools will enhance customer outcomes, reduce service terminations, and ultimately strengthen the Company's customer service and regulatory accountability.

Q: DO YOU AGREE WITH MR. FARNSWORTH'S COMMENTS REGARDING FORMAL POLICIES AND PROCEDURE ON SECURITY DEPOSITIS?

No. I do agree with Mr. Farnsworth's observation that some customers may be hesitant to seek assistance or may feel uncomfortable engaging with assistance organizations. However, this reality does not eliminate the Company's responsibility to proactively and formally screen applicants for low-income status prior to assessing a security deposit.

I continue to recommend that the Company adopt written policies for income screening in advance of charging a security deposit. This will help ensure that eligible customers receive the low-income deposit waivers they are entitled to under 52 Pa. Code § 56.32. While the Company's willingness to include language in its Denial of Credit Statement is a positive step, it is not sufficient on its own. Improving disclosure does not correct the impact on the customer nor does it eliminate concerns of fairness, accessibility, or possible unfair burden. Clear, proactive communication about waiver eligibility is essential for ensuring that

customers are informed and have the opportunity to access protections afforded by law.

In addition, with respect to the refunding of deposits, I continue to urge the Company to give low-income customers—who were incorrectly charged a deposit—the option to receive a refund, rather than having the amount automatically applied as a credit to their account. In Mr. Farnsworth's rebuttal testimony, he states "we believe that it is appropriate to follow a consistent policy for all customer".[1]Treating all customers the same, in this regard fails to account for the financial realities that disproportionately affect low-income households. Policies should be designed with consideration for those challenges and should not unintentionally disadvantage those already facing economic hardship.

Q: DO YOU AGREE WITH MR. FARNWORTH'S STATEMENTS REGARDING THE ELIMINATION OF THE $3.95 CREDIT/DEBIT CARD FEES?

A: No. Assessing a $3.95 processing fee for credit and debit card payments of utility bills is not reasonable nor is it in public interest. This fee unfairly penalizes customers who choose – or are often forced – to use a more efficient and modern method of payment.

While the Company acknowledges that there are no true "free" payment options, as customers also experience costs to make cash or check payments. They fail to

[1] Wellsboro Statement No. 4R

acknowledge processing these forms of payment carry administrative and operational expenses which are included in base rate making.

There is a fundamental contradiction in how payment processing costs are treated. The administrative costs of handling checks, and cash are included in the utility revenue requirement – and therefore shared among all customers. However, the credit/debit card fee is being passed only to customers using that method, creating an unfair and discriminatory issue.

If the principle of cost causation is to be applied consistently, then card processing fees – like other administrative payment costs – should be treated as part of the utility's cost of doing business, not an add-on fee to customers. Customers choosing a secure, fast, and modern method of payment should not be penalized.

The Company's statement that customers using credit cards to receive rewards or "perks" is irrelevant. In many cases, the fee far exceeds any reward value the card holder may receive. Any "perk" a customer may receive does not justify charging a $3.95 fee. Most importantly, many customers use credit cards out of necessity, not to earn points, but to avoid late payments and or possible service disconnections.

Although I recognize there are utilities that pass along service fees onto their customers, it should also be noted utilities have recognized the inequity and inefficiency of these charges and have moved to eliminate them. For example:

- Columbia Gas of PA. No fees apply to residential customers for credit/debit/Pay Pay/Venmo one-time card payments.[2]
- Pennsylvania American Water eliminated its $1.95 fee for credit card payments in 2023 (PA PUC Docket No. R-2022-3031672).[3]
- Pittsburgh Water and Sewer Authority (PWSA) similarly removed credit card convenience fees to enhance accessibility and reduce barriers to payment (PWSA Customer Service Update, 2022).[4]

Q. **DO YOU HAVE ANY COMMENTS ON THE COMPANY'S CONCERN WITH INCREASED CREDIT CARD USAGE ON FUTURE RATE CASES?**

Yes, I would agree that the removal of the $3.95 represents the possibility of increased usage of credit/debit cards. However, these processing fees are a small part of the Company's overall operating expenses. The Company has not provided any evidence that increased usage of credit card payments would outweigh the benefits to customers or significantly impact on their revenuer requirement which already includes administrative expenses.

As I stated previously, processing fees would reduce other operation expenses such as check processing fees, reduction in posting of payments, reduced past due balances, and collection costs. It is important to weigh both the cost increase along

[2] http://www.columbiagaspa.com/search-results#/?term=payment%20fees

[3] PA PUC Docket No. R-2022-3031672

[4] [4] https://www.pgh2o.com/residential-commercial-customers/account-billing-info/update-contact-information

with the reduction of administrative costs and the elimination of the processing fee brings.

There are several utilities in Pennsylvania and neighboring states who have eliminated these fees without experiencing destabilizing costs or large rate impacts to their customers. The fee is unfair and severely burdens low-income customers who rely on credit cards to pay their bills and therefore should be eliminated. For these reasons, I continue to support the elimination of the $3.95 processing fees.

Q: DOES THIS CONCLUDE YOUR SURREBUTTAL TESTIMONY?

A: Yes.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No. R-2025-3054392
	:	
Wellsboro Electric Company	:	

VERIFICATION

I, LeeAnn Wise, hereby state that the facts above set forth in my Surrebuttal Testimony, OCA Statement No. 4SR, are true and correct to the best of my knowledge, information, and belief and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa.C.S. § 4904 (relating to unsworn falsification to authorities).

DATED: August 28, 2025

Signature: */s/ LeeAnn Wise*
LeeAnn Wise

Address: Office of Consumer Advocate
555 Walnut Street
Harrisburg, PA 17101

OSBA EXHIBIT NO. 1

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	**Docket No. R-2025-3054394**
v.	:	
	:	
Citizens' Electric Company of Lewisburg, PA	:	
	:	

OFFICE OF SMALL BUSINESS ADVOCATE'S
ADMITTED
TESTIMONY AND EXHIBITS

The Office of Small Business Advocate ("OSBA") admitted the enclosed testimony and exhibits, as evidence into the evidentiary record, as OSBA EXHIBIT NO. 1, at the Evidentiary Hearing, held on September 4, 2025, in the above-captioned proceeding:

- Direct Testimony and Exhibits of Justin B. Farr, labelled OSBA Statement No.1, with Exhibit JBF-1, Exhibit JBF-2, and Exhibit JBF-3, with signed Verification of Justin B. Farr.
- Rebuttal Testimony of Justin B. Farr, labelled OSBA Statement No.1-R, with signed Verification of Justin B. Farr.
- Surrebuttal Testimony and Exhibit of Justin B. Farr, labelled OSBA Statement No.1-SR, with associated Exhibit JBF-1SR with signed Verification of Justin B. Farr.

Date: September 4, 2025

COMMONWEALTH OF PENNSYLVANIA

July 15, 2025

The Honorable Mary D. Long
Administrative Law Judge
Pennsylvania Public Utility Commission
Piatt Place
301 Fifth Avenue, Suite 220
Pittsburgh, PA 15222

Re: Pennsylvania Public Utility Commission v. Citizens' Electric Company of Lewisburg, PA / Docket No. R-2025-3054394

Dear Judge Long:

Enclosed please find the Direct Testimony and Exhibits of Justin B. Farr, labelled OSBA Statement No.1, on behalf of the Office of Small Business Advocate ("OSBA"), in the above-referenced proceeding.

As evidenced by the enclosed Certificate of Service, all known parties will be served, as indicated.

If you have any questions, please do not hesitate to contact me.

Sincerely,

/s/ Rebecca Lyttle

Rebecca Lyttle
Assistant Small Business Advocate
Attorney ID No. 201399

Enclosures
cc: PA PUC Secretary Matthew L. Homsher (Cover Letter & Certificate of Service only)
Kevin Higgins / Rebecca Forbes / Justin Farr
Joseph Kubas
Parties of Record

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	**:**	
	:	
v.	**:**	**Docket No. R-2025-3054394**
	:	
Citizens' Electric Company of Lewisburg, PA	**:**	
	:	

Direct Testimony & Exhibits

of

Justin B. Farr

on behalf of

Pennsylvania Office of Small Business Advocate

Topics:

Revenue Requirement Adjustments
Cost of Service
Revenue Allocation

Date Served: July 15, 2025

Date Submitted for the Record: _____

DIRECT TESTIMONY OF JUSTIN B. FARR

Section I - Introduction

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Justin B. Farr. My business address is 111 East Broadway, Suite 1200, Salt Lake City, Utah, 84111.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am a Director in the firm of Energy Strategies, LLC. Energy Strategies is a private consulting firm specializing in economic and policy analysis applicable to energy production, transportation, and consumption.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?

A. My testimony is being sponsored by the Pennsylvania Office of Small Business Advocate ("OSBA").

Q. PLEASE DESCRIBE YOUR PROFESSIONAL EXPERIENCE AND QUALIFICATIONS.

A. My academic background includes a B.S. in economics and an M.B.A. from the University of Utah. After completing my undergraduate degree and while I was completing courses for my master's degree, I worked in the Utah Governor's Office as an economist focused on revenue forecasting and tax policy. I joined Energy Strategies in 2005, where I assist private and public sector clients in the areas of energy-related economic and policy analysis, including evaluation of electric and gas utility rate matters.

From 2013 to 2017 and again from 2020 to early 2022, I worked at PacifiCorp, a six-state electric utility that operates in Utah, Wyoming, Idaho, Oregon, Washington, and California. My roles at PacifiCorp included Manager of Economic & Financial Analysis where I led teams of engineers and plant managers in developing economic solutions for optimizing existing thermal and renewable infrastructure investment, and Assistant Manager of Regulation where I focused on the company's internal 10-year plan. Between 2017 and 2019, I served as Vice President of Financial Planning at Magnum Development where I supported the commercial development of the company's underground salt dome assets. My qualifications are attached in the Appendix to this testimony.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION?

A. Yes. I testified in a proceeding concerning the Second DER Management Plan filed by PPL Electric Utilities Corp, Docket No. P-2024-3049223.

Q. HAVE YOU TESTIFIED BEFORE UTILITY REGULATORY COMMISSIONS IN OTHER STATES?

A. Yes. I have provided testimony before the Utah Public Service Commission and the Indiana Utility Regulatory Commission.

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY IN THIS PROCEEDING?

A. My testimony addresses recommended revenue requirement adjustments. The absence of comment on my part regarding a particular issue or revenue requirement item does not signify support for (or opposition to) the Company's filing with respect to that issue.

Q. ARE YOU MAKING A RECOMMENDATION FOR A SPECIFIC TOTAL REVENUE REQUIREMENT IN THIS CASE?

A. No. My revenue requirement adjustment recommendations address a limited number of issues. Therefore, I am not offering a recommendation for a specific total revenue requirement.

Q. PLEASE SUMMARIZE YOUR PRIMARY CONCLUSIONS AND RECOMMENDATIONS.

A. I offer the following recommendations and conclusions:

1) I recommend certain adjustments that will have the effect of reducing revenue requirement by $269,644 relative to the $1.7 million increase proposed by the Company. My recommended adjustments are outlined in Table JBF-1 presented later in my testimony. My recommended reduction does not account for or incorporate any other adjustments advanced by other parties that are not specifically addressed in my testimony.

2) I conclude that the cost of service study aligns with the principles of cost causation and that Citizens' proposed revenue allocation falls within the range of reasonableness.

Section II - Revenue Requirement Adjustments

Q. BRIEFLY DESCRIBE THE REVENUE REQUIREMENT INCREASE BEING REQUESTED BY CITIZENS' IN THIS CASE.

A. Citizens' Electric Company of Lewisburg, Pennsylvania ("Citizens'" or "Company") is requesting a $1,794,525 increase in annual distribution revenue,

representing a 29.6% increase over present distribution rates. The requested increase is based on a Fully Projected Future Test Year ("FPFTY") ending December 31, 2026, and is designed to produce an overall rate of return of 8.49% on Citizens' rate base.[1]

Q. DO YOU HAVE ANY RECOMMENDED ADJUSTMENTS TO CITIZENS' PROPOSED REVENUE REQUIREMENT?

A. Yes. My recommended adjustments would reduce Citizen's proposed revenue requirement increase by $269,644. As discussed in greater detail later in my testimony, this reduction incorporates a proxy return on equity ("ROE") of 10.0%, which is derived from the ROE authorized by the Commission for the Distribution System Improvement Charge ("DSIC") applicable to most electric utilities in the state. Table JBF-1 presents a summary of my recommended adjustments.

[1] Direct Testimony of Howard S. Gorman (Citizens' Statement No. 1), page 3.

Table JBF-1
Summary of OSBA Adjustments to Citizens' Revenue Requirement

	OSBA Adjustments	Revenue Requirement
Revenue Requirement Increase Requested by Citizens'		**1,794,525**
O&M Adjustments		
Remove POLR/PJM-2024 Expense	(8,298)	
Adjust Generic Escalation Assumptions	(16,051)	
Remove Portion of Rate Case Printing Expense	(1,667)	
Income Tax Rate Adjustment		
Change PA Income Tax Rate from 9.99% to 7.49%	(89,131)	
Proxy Return on Equity		
Change ROE from 11.65% to Proxy 10%	(138,425)	
Impact of GRT gross up	(15,899)	
Rounding	(173)	
Adjusted Revenue Requirement Increase		**1,524,881**

I provide more detail for each of these recommended adjustments as follows:

POLR/PJM-2024 Expense Adjustment

Q. PLEASE EXPLAIN THE BASIS FOR YOUR ADJUSTMENT.

A. In response to interrogatory I&E-RE-7-D, Nathan Johnson, President, and CEO of Citizens' Electric Company, agreed that the POLR/PJM-2024 expense that had been included as a rate case expense and subsequently rolled into O&M expense is actually a generation-related cost that was inadvertently included.[2] Mr. Johnson

[2] Citizens' response to I&E-RE-7-D

noted that this expense would be removed by Company witness Mr. Gorman in rebuttal testimony.

Q. PLEASE EXPLAIN YOUR ADJUSTMENT.

A. My adjustment simply recommends correcting for this error by removing the generation-related expense from this rate case.

Q. WHAT IS THE IMPACT OF THIS ADJUSTMENT?

A. As reported in Table JBF-1, removing the POLR/PJM-2024 expense reduces revenue requirement by $8,298.

General Inflationary Factor Adjustment

Q. PLEASE EXPLAIN CITIZENS' USE OF A GENERAL INFLATIONARY FACTOR TO ESCALATE CERTAIN O&M EXPENSES.

A. In the process of developing expected costs for FPFTY 2026, the Company must forecast or project how historical expenses will increase or decrease. For budget items that have relatively few sources of expense, the Company develops forecasts based on known historical trends and future price projections supplied by vendors or other industry sources. However, for budget items with numerous contributing expense sources, the sheer number and small size of individual components make it impractical to employ a "bottom-up" approach to project expenses for the future test year. For these budget items, the company employs a general inflationary factor of 3.0%.[3]

[3] Citizens' response to I&E-RE-5-D.

Q. PLEASE DESCRIBE IN DETAIL HOW THE COMPANY HAS CALCULATED FPFTY 2026 EXPENSES FOR BUDGET ITEMS THAT RELY ON THIS 3.0% GENERIC INFLATION FACTOR.

A. Rather than using actual data for HTY 2024 as a starting point for escalating to calculate FPFTY 2026 values, the Company used a three-step process to develop 2024 values, which were then escalated by 3% to arrive at FTY 2025 values and then escalated once again to arrive at FPFTY 2026 values. Based upon my analysis of I&E-RE-5-D Attachment A[4], the Company utilized the following three-step process to arrive at 2024 values:

- Step 1: the Company calculated "Annualized" 2024 values based on actual values from January through September of 2024. It's unclear how the Company determined which escalation factors to use for each budget item, but the sum of all of the budget items identified in I&E-RE-5-D Attachment A represented a 3.1% increase over the sum of all 2023 actual values (note: the annual percent change for individual budget items between 2023 and the annualized 2024 values varied between -98% and 608%). The sum total of "Annualized" values for all budget items that the Company identified as being escalated by a general inflationary factor equals $310,199.
- Step 2: the Company calculated a three-year average for each budget item using actual 2022, actual 2023, and annualized 2024 values. The sum total three-year average for these budget items equals $306,744, which is a

[4] JBF WP-2 I&E-RE-5-D Attachment A (Direct)

1.9% increase over the total 2023 value and a 1.1% reduction from the annualized 2024 value.

- Step 3: The Company then "Normalized" the three-year average values by escalating each budget item value by 3.0%. The result of this escalation is labeled "Normalized 3yr Avg" and the Company represents this as the 2024 values. The sum total equals $315,946.

Using the "Normalized 3yr Avg" values as a proxy for actual 2024 values, the company then calculated 2025 values by escalating each budget item by 3.0%. The sum total equals $325, 425. And finally, the company escalated each calculated 2025 budget item one more time by 3.0% for the values that are included in FPFTY 2026. The total equals $335,188. An excel worksheet with formulae intact for the calculations that I have just described is included in my attached work paper JBF WP-2 I&E-RE-5-D Attachment A (Direct).

Q. DO YOU AGREE WITH THE COMPANY'S METHODOLOGY?

A. Yes, I agree with the general approach of using a generic inflationary factor on budget items that are difficult to employ a "bottom-up" approach, but I propose two modifications to Citizens' calculations.

Q. HOW DO YOU RECOMMEND MODIFYING THE COMPANY'S METHODOLOGY?

A. I recommend using actual 2024 values instead of the calculated normalized values. However, since actual 2024 values have not been provided, I recommend using the "3-year average" values the Company calculated to represent 2024 values instead of the Company's "Normalized 3yr Avg" values. The sum of the

normalized values that the Company uses for 2024 values equates to a 5.0% annual increase between 2024 and 2023 values, which seems high considering that the compound annual growth rate ("CAGR") is 1.6% between 2019 and 2023[5] (note: the CAGR is 1.8% between 2020 and 2023, and 0.1% between 2021 and 2023). If the calculated 3-year average values are used for 2024, as I recommend, the annual growth rate from 2023 to 2024 is 1.9%[6], which is still greater than actual recent escalation for these budget items.

My second recommendation is to use 2.0% as a general inflationary factor for these budget items to escalate to FTY 2025 and FPFTY 2026 values instead of the 3.0% proposed by Citizens'. A 2.0% inflationary factor is more consistent with recent inflation experienced by these budget items as a group. These recommendations are illustrated in Table JBF-2.

Table JBF-2
Proposed Modification to Expenses Escalated
Using Generic Inflationary Factor

Company Proposed Methodology

Year	Sum of Expenses	% Change
2019	$282,046	
2020	$285,428	1.2%
2021	$300,083	5.1%
2022	$309,146	3.0%
2023	$300,888	-2.7%
Normalized 2024	$315,946	5.0%
2025	$325,425	3.0%
2026	$335,188	3.0%

OSBA Proposed Methodology

Year	Sum of Expenses	% Change
2019	$282,046	
2020	$285,428	1.2%
2021	$300,083	5.1%
2022	$309,146	3.0%
2023	$300,888	-2.7%
3 Year Ave 2024	$306,744	1.9%
2025	$312,879	2.0%
2026	$319,137	2.0%

[5] JBF WP-2 I&E-RE-5-D Attachment A (Direct)
[6] JBF WP-2 I&E-RE-5-D Attachment A (Direct)

Q. WHAT IS THE IMPACT OF THIS ADJUSTMENT?

A. As reported in Table JBF-1, this adjustment would reduce revenue requirement by $16,051 in FPFTY 2026.

Rate Case Printing Expense

Q. PLEASE DESCRIBE CITIZENS' REQUEST TO RECOVER EXPENSES ASSOCIATED WITH THIS RATE CASE PROCEEDING.

A. Citizens' seeks recovery of costs incurred because of filing this rate case. The total costs included in the filing equal $326,667. Citizens' recommends recovering this expense over three years so that each annual payment equals $108,889. One of the line items included in the budget for rate case expenses is "Printing, other" for $10,000. In response to I&E-RE-6-D, Citizens' summarized the amounts requested in the last three rate cases and the amounts actually spent. In the 2016 rate case, Citizens' claimed $13,000, but only spent $4,335. In the 2019 rate case, Citizens' claimed $13,000, but only spent $3,767. In the 2022 rate case, Citizens' claimed $15,000, but only spent $4,614.[7] It is clear that Citizens' has a history of over-budgeting how much will be required for printing expenses.

Q. WHAT IS YOUR RECOMMENDATION REGARDING RATE CASE PRINTING EXPENSE?

A. I recommend reducing the "Printing, other" rate case expense to $5,000, since the Company has not used more than $5,000 in any of the last three rate cases.

Q. WHAT IS THE IMPACT OF THIS ADJUSTMENT?

[7] Citizens' Response to I&E-RE-6-D

A. Because the rate case expense is spread over three years, a $5,000 reduction in printing expense results in a reduction to revenue requirement of $1,667 in FPFTY 2026, as reported in Table JBF-1.

Pennsylvania Corporate Income Tax Rate Adjustment

Q. DESCRIBE THE PENNSYLVANIA CORPORATE NET INCOME TAX RATE AND ITS HISTORY.

A. For nearly three decades, Pennsylvania maintained a flat Corporate Net Income ("CNI") Tax rate of 9.99%, among the highest in the United States. This rate remained unchanged from 1995 until 2022. In July 2022, the Pennsylvania General Assembly enacted Act 53-2002 (H.B. 1342), initiating a phased reduction of the CNI Tax rate over nine years. The schedule for the rate reductions shown in Table JBF-3 as follows[8]:

Table JBF-3
Pennsylvania Corporate Net Income Tax Rates

Tax Year	CNIT Rate
January 1, 2023 - December 31, 2023	8.99 percent
January 1, 2024 - December 31, 2024	8.49 percent
January 1, 2025 - December 31, 2025	7.99 percent
January 1, 2026 - December 31, 2026	7.49 percent
January 1, 2027 - December 31, 2027	6.99 percent
January 1, 2028 - December 31, 2028	6.49 percent
January 1, 2029 - December 31, 2029	5.99 percent
January 1, 2030 - December 31, 2030	5.49 percent
January 1, 2031 and each taxable year thereafter	4.99 percent

[8] https://www.pa.gov/agencies/revenue/resources/tax-rates/corporation-tax-rates.html

Q. WHAT PENNSYLVANIA CNI TAX RATE WAS USED IN THE DEVELOPMENT OF THE COMPANY'S REQUESTED INCREASE IN REVENUE REQUIREMENT IN THIS CASE?

A. The Company used 9.99% as the Pennsylvania corporate income tax rate.[9]

Q. WHAT PENNSYLVANIA CNI TAX RATE WAS USED IN THE LAST RATE CASE?

A. In docket R-2022-3032369, Citizens' last general rate case, Citizens' initial application included a 9.99% CNIT rate.[10] However, as part of the settlement agreement, parties agreed to an 8.99% CNIT rate, which is equal to the new phased rates enacted through Act 53-2002 for calendar year 2023. The Settlement Terms included in the ALJ's Recommended Decision letter stated:

> The Parties agree that the Pennsylvania Corporate Net Income ("CNI") Tax rate in this proceeding will be set at 8.99%. The Company will reflect actual CNI rates for the post-2023 tax years through the Company's State Tax Adjustment Surcharge, or future base rate proceedings.[11]

Q. WHAT PENNSYLVANIA CNI TAX RATE DO YOU RECOMMEND?

A. I recommend using 7.49% as the CNI Tax rate for FPFTY 2026, which is the tax rate enacted by Act 53-2022 for calendar year 2026, and to require the company to reflect actual CNI rates for the post-2026 tax years through the Company's State Tax Adjustment Surcharge until the next rate case proceeding.

[9] Direct Testimony of Howard S. Gorman (Citizens' Statement No. 1), page 11.
[10] R-2022-3032369, Citizens' Statement No. 1, page 12.
[11] Recommended Decision Letter of Administrative Law Judge's Eranda Vero and Charece Z. Collins, page 5.

Q. WHAT IS THE IMPACT OF THIS ADJUSTMENT?

A. As reported in Table JBF-1, this adjustment would reduce revenue requirement by $89,131 in FPFTY 2026.

Common Equity Cost Rates

Q. WHAT IS THE PERFORMANCE FACTOR ADJUSTMENT?

A. Citizens' witness Nathan Johnson explains that Section 523 of the Public Utility Code provides the Commission's guidelines for performance adjustments. He states that counsel has advised him that the Public Utility Code identifies several criteria to be considered in assessing the performance of a fixed utility for purposes of a performance factor adjustment, including consideration of any relevant and material evidence of efficiency, effectiveness, and adequacy of service. Mr. Johnson provides information on Citizens' operations, which he asserts support receiving a performance factor adjustment.[12]

Q. WHAT IS CITIZENS' PROPOSED PERFORMANCE FACTOR ADJUSTMENT?

A. Citizens' proposes a performance factor adjustment of a 5-basis point addition to the cost of common equity.[13]

Q. WHAT IS YOUR RESPONSE TO CITIZENS' PROPOSED PERFORMANCE FACTOR ADJUSTMENT?

A. Utilities are expected to provide safe and reliable service to their customers. They should also deliver quality customer service, upgrade their systems, and manage

[12] Direct Testimony of Nathan Johnson (Citizens' Statement No.4), pp. 9-12.
[13] Revised Direct Testimony of Dylan W. D'Ascendis (Joint Statement No. 2), page 52.

their costs effectively. Utilities already receive a guaranteed rate of return for performing these functions. Providing an additional upward adjustment for effective operations, at the expense of customers, is excessive.

Q. WHAT IS THE SIZE ADJUSTMENT?

A. Citizens' witness Dylan D'Ascendis explains that the Companies' smaller size relative to the Electric Utility Proxy Group indicates greater relative business risk for the Company because, all else being equal, size has a material bearing on risk. He asserts that size affects business risk because smaller companies generally are less able to cope with significant events that affect sales, revenues, and earnings. For example, smaller companies face more risk exposure to business cycles and economic conditions, both nationally and locally. Additionally, Mr. D'Ascendis states that the loss of revenue from a few larger customers would have a greater effect on a small company than on a bigger company with a larger, more diverse customer base.[14]

Q. WHAT IS CITIZENS' PROPOSED SIZE ADJUSTMENT?

A. Citizens' proposes a size factor adjustment of an 85-basis point addition to the cost of common equity.[15]

Q. WHAT IS YOUR RESPONSE TO CITIZENS' PROPOSED SIZE FACTOR ADJUSTMENT?

A. The Company's arguments for an upward adjustment focus solely on potential losses, without acknowledging the possibility of potential gains. While it is true that a small company losing a large customer could experience reduced revenues,

[14] Revised Direct Testimony of Dylan W. D'Ascendis (Joint Statement No. 2), page 47.

[15] Revised Direct Testimony of Dylan W. D'Ascendis (Joint Statement No. 2), page 51.

it is also possible for the company to gain large customers, therefore increasing revenues. At the very least, new customers could offset the impact of losing existing ones. Customers should not bear the burden of shielding a utility from every possible risk, particularly when utilities have the ability to file a rate case with the Commission to address extreme risks if they arise. An 85-basis-point upward adjustment to account for unspecified risks is excessive.

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE PERFORMANCE FACTOR ADJUSTMENT, THE SIZE FACTOR ADJUSTMENT?

A. I recommend eliminating the performance factor adjustment entirely and lowering or removing the size factor adjustment. These changes support, and help justify, a lower return on equity ("ROE") for the company, which I will discuss in greater detail below.

Proxy Return on Equity Adjustment

Q. WHAT ROE IS CITIZENS' REQUESTING IN THIS PROCEEDING?

A. Citizens' witness Dylan W. D'Ascendis recommends a ROE of 11.65%.[16]

Q. DO YOU SUPPORT CITIZENS' REQUESTED ROE?

A. No.

Q. WHAT OBSERVATIONS HAVE YOU MADE IN REGARD TO CITIZENS' REQUESTED ROE?

[16] Revised Direct Testimony of Dylan W. D'Ascendis (Joint Statement No. 2), page 6.

A. A comparison of Citizens' requested ROE of 11.65% with the most recent Report on the Quarterly Earnings of Jurisdictional Utilities for the year ending December 31, 2024, produced by the Bureau of Technical Utility Services indicates to me that the requested 11.65% is too high and should be adjusted down. Based on the report, the current market indicated ROE as calculated by the Bureau of Technical Utility Services should fall within the range of 9.17% to 11.23%[17]. This report is included as Exhibit JBF-1 at the end of my testimony.

A review of recently completed rate cases across the country for electric distribution companies that were either settled, or fully litigated within the last year, suggests that the proper ROE is likely near the lower part of the range provided by the Bureau of Technical Utility Services. The average authorized ROE in cases involving electric distribution companies that were approved between June 1, 2024, and June 30, 2025, is 9.50%. Expanding the universe of approved rate cases to include vertically integrated electric utilities over the same period increases the authorized ROE to 9.77%. A detailed listing of approved ROE's from rate cases finalized over the last year is included at the end of my testimony as Exhibit JBF-2. I present the results for electric distribution utilities in Table JBF-4.

[17] Exhibit JBF-1, Report on the Quarterly Earnings of Jurisdictional Utilities (Year ending December 31, 2024, page 14.

Table JBF-4
Survey of Approved ROE's for Electric Distribution Companies Between June 1, 2024 & June 30, 2025

State	Company	Case identification	Approved Date	ROE (%)
MD	Potomac Electric Power Company	C-9702	6/10/2024	9.50
MA	Fitchburg Gas and Electric Light Company, In	DPU 23-80	6/28/2024	9.40
NY	Central Hudson Gas & Electric Corporation	C-23-E-0418	7/18/2024	9.50
MA	Massachusetts Electric Company	DPU 23-150	9/30/2024	9.35
DC	Potomac Electric Power Company	FC-1176	11/25/2024	9.50
ME	Versant Power	D-2023-00336	3/13/2025	9.35
TX	AEP Texas Inc.	D-56165	10/3/2024	9.76
NJ	Public Service Electric and Gas Company	D-ER23120924	10/9/2024	9.60
TX	CenterPoint Energy Houston Electric, LLC	D-56211	3/13/2025	9.65
NY	Orange and Rockland Utilities, Inc.	C-24-E-0060	3/20/2025	9.75
NH	Liberty Utilities (Granite State Electric) Corp.	D-DE-23-039	3/25/2025	9.10

Q. DO YOU RECOMMEND A SPECIFIC ROE?

A. No, I do not have a recommendation for a specific ROE but rather defer to analysis and recommendations promulgated by the Office of Consumer Advocate ("OCA") and the Bureau of Investigation and Enforcement ("I&E"). However, for purposes of my testimony, I have assumed a proxy 10.0% ROE based upon the Commission's approved ROE for Distribution System Improvement Charge (DSIC) included in the most recent Report on the Quarterly Earnings of Jurisdictional Utilities[18] for the year ended December 31, 2024, produced by the Bureau of Technical Utility Services referenced previously.

Q. WHAT IS THE REVENUE REQUIREMENT IMPACT OF USING A PROXY 10.0% ROE?

[18] Exhibit JBF-1, Report on the Quarterly Earnings of Jurisdictional Utilities (Year ending December 31, 2024, page 15.

A. As reported in Table JBF-1, this adjustment would reduce revenue requirement by $138,425 in FPFTY 2026.

Section III - Class Cost of Service and Revenue Allocation

Q. DID CITIZENS' PERFORM A CLASS COST OF SERVICE STUDY?

A. Yes, Citizens' completed an allocated class cost of service study ("ACOS") that follows the traditional three-step process of: 1) functionalization of rate base and costs; 2) classification of functionalized costs as demand-related, commodity-related or customer-related; and 3) class allocation of the functionalized, classified costs among the rate classes.

Q. DO YOU HAVE ANY COMMENTS ON THE COST ALLOCATION METHODS USED BY CITIZENS'?

A. Yes. As a general matter, I find the cost allocation methods employed by Citizens, as outlined by Mr. Gorman, to align with the principles of cost causation. Therefore, I am not proposing any modifications to the Company's cost allocation approach in this proceeding.

Q. PLEASE DESCRIBE CITIZENS' REVENUE ALLOCATION PROPOSAL.

A. Citizens' revenue allocation proposal is guided by the objectives of 1) moving each class closer to cost of service as computed in the ACOS, and 2) mitigating extreme rate impacts on rate classes and on customer subgroups.[19]

Q. WHAT IS YOUR ASSESSMENT OF CITIZENS' REVENUE ALLOCATION PROPOSAL?

[19] Direct Testimony of Howard S. Gorman (Citizens' Statement No. 1), page 28.

A. The Company's revenue allocation proposal reasonably balances moving class revenue recovery in the direction of cost causation, while adhering to the principle of gradualism. All classes have reductions in the subsidy paid or received. In my opinion, the proposed revenue allocation falls within the range of reasonableness.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

APPENDIX A

Vitae & Expert Testimony List

of

Justin B. Farr

APPENDIX A

Justin B. Farr

Director, Energy Strategies, L.L.C.
111 East Broadway, Suite 1200, Salt Lake City, UT 84111
jfarr@energystrat.com

Vitae

Professional Experience

Energy Strategies, Salt Lake City UT, April 2022 - Present
An energy consulting firm focused on regulatory services, policy, and markets serving power producers, transmission developers, utilities, government agencies, NGO's, and large energy users

Director

- Perform energy-related economic and policy analysis, regulatory intervention, and strategic negations on behalf of industrial, commercial, and public sector interests
- Provide risk management and market fundamentals analysis to large consumers of natural gas
- Executive director of the Utah Association of Energy Users

PacifiCorp, Salt Lake City UT, January 2020 – April 2022
Berkshire Hathaway owned electric utility serving over 1.6 million customers in Utah, Oregon, Washington, Wyoming, Idaho, and parts of Northern California

Assistant Manager of Regulation, March 2021 – April 2022
Senior Fuels Manager, January 2020 – March 2021

- Performed rate projections tied to the company's 10-year plan
- Provided testimony on the Renewable Energy Credits balancing account
- Procured fuel and managed contracts for company owned and jointly owned thermal plants

Magnum Development, Holladay UT, 2017 – Oct 2019
Private Equity backed developer of utility-scale storage in underground salt caverns. Developing storage for natural gas, compressed air created from renewable electricity, green hydrogen, and helium.

Vice President of Financial Planning, January 2019 – October 2019
Assistant Vice President of Financial Planning, February 2017 – December 2018

- Worked on commercial team developing bidding strategies and analysis to support joint development negotiations

- Managed all financial and economic modeling across all of Magnum's business verticals including: Magnum Midstream (Natural Gas), Magnum Compressed Air Energy Storage (CAES), Magnum Hydrogen, and Magnum Industrial Gases (Helium)

PacifiCorp, Salt Lake City UT, 2013 – 2017
Berkshire Hathaway owned electric utility serving over 1.6 million customers in Utah, Oregon, Washington, Wyoming, Idaho, and parts of Northern California

Manager Economic & Financial Analysis, August 2015 – February 2017
Senior Financial Planning Analyst, October 2013 – August 2015

- Managed team of Sr. Financial Analysts responsible for economic analysis, internal audit of joint owned plants, and annual budget of resource development division
- Led team of engineers, plant managers, and vice presidents in developing economic solutions that optimized existing thermal and renewable infrastructure investment
- Developed economic models to explore new resource development opportunities such as utility scale solar and battery installations
- Prepared annual cost of generation report for senior management

Energy Strategies, Salt Lake City UT, 2005 – 2013
An energy consulting firm focused on regulatory services, policy, and markets serving power producers, transmission developers, utilities, government agencies, NGO's, and large energy users

Senior Consultant, January 2010 – October 2013
Consultant, July 2005 – December 2009

- Developed strategies for clients with energy infrastructure that optimized environmental performance and financial objectives while meeting their utility requirements
- Performed market studies focused on thermal & renewable energy need, transmission availability, pricing, and impacts of public policy initiatives. Studies were designed to inform and improve clients' energy decisions including risk management and procurement strategy.

Education

- Master of Business Administration, University of Utah, May 2005
- Bachelor of Science in Economics/Business Minor, University of Utah, May 2000
- Graduated Magna Cum Laude; GPA 3.92
- Honors at Entrance Scholarship; 1999-2000 Law & Economic Society Fellowship

Expert Testimony

"In the Matter of the Petition of PPL Electric Utilities Corp for Approval of its Second Distributed Energy Resources Management Plan," Public Utilities Commission of **Pennsylvania**, Docket No. P-2024-3049223. Direct testimony submitted September 17, 2024. Surrebuttal testimony filed January 22, 2024.

"In the Matter of the Verified Petition of Indiana Michigan Power Company for Approval of Modifications to its Industrial Power Tariff – Tariff IP," **Indiana** Utility Regulatory Commission, Cause No. 46097. Direct testimony submitted October 15, 2024. Cross-Answering testimony filed November 4, 2024. Settlement testimony filed December 4, 2024.

"In the Matter of the Application of Rocky Mountain Power for Authority to Revise Rates in Tariff Schedule 98, Renewable Energy Credits Balancing Account," **Utah** Public Service Commission, Docket No. 22-035-07. Direct testimony submitted March 15, 2022.

EXHIBIT JBF-1

PENNSYLVANIA PUBLIC UTILITY COMMISSION

Public Meeting held May 8, 2025

Docket Number: M-2025-3054401

BUREAU OF TECHNICAL UTILITY SERVICES

REPORT ON THE QUARTERLY EARNINGS

OF JURISDICTIONAL UTILITIES

FOR THE YEAR ENDED

December 31, 2024

Stephen M. DeFrank, Chairman
Kimberly Barrow, Vice Chair
Kathryn L. Zerfuss
John F. Coleman, Jr., Joint Statement, Dissenting
Ralph V. Yanora, Joint Statement, Dissenting

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This chart depicts the overall and equity returns (actual and adjusted) for the filing utilities for the current quarter. The last authorized equity returns and the year authorized is also shown.

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This is a historical chart that shows the most recent rate cases for select companies in electric, gas, and water. A docket number followed by their final return on equity and year is also given.

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Criteria for determining the industry barometer groups used in ROE calculations. Also, provides details of the Discounted Cash Flow equation and Capital Asset Pricing Model equation.

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The market indicated common equity cost rate range consists of data used from the electric barometer groups and is based on a series of calculations to average the DCF methods. Also, indicates Distribution System Improvement Charge Return.

Attachment F – Historic DCF and CAPM – Electric..... 19
Historic barometer group DCF and CAPM average ROEs.

Attachment F – Electric Barometer Group Calculation of a Current and 52 Week Average Dividend Yield..... 20-21
Electric barometer companies are used to calculate a current DCF in the first chart. The second chart demonstrates the companies 52-week average DCF. A final average of the two calculations is also shown at the bottom.

Attachment F – Development of a Representative Dividend Growth Rate..... 22
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Attachment G – Market Based Returns on Equity – Gas..... 23
The market indicated common equity cost rate range consists of data used from the gas barometer groups and is based on a series of calculations to average the DCF methods. Also, indicates Distribution System Improvement Charge Return.

Attachment G – Historic DCF and CAPM – Gas 24
Historic barometer group DCF and CAPM average ROEs, including a linear trend line graph.

Attachment G – Gas Barometer Group Calculation of a Current and 52 Week Average Dividend Yield 25
Gas barometer companies are used to calculate a current DCF in the first chart. The second chart demonstrates the companies 52-week average DCF. A final average of the two calculations is also shown at the bottom.

Attachment G – Development of a Representative Dividend Growth Rate 26
Multiple sources of the gas barometer companies projected 5-year Earnings Per Share are used to calculate the Group Average Dividend Growth Estimate.

Attachment H – Market Based Returns on Equity – Water 27
The market indicated common equity cost rate range consists of data used from the water barometer groups and is based on a series of calculations to average the DCF methods. Also, indicates Distribution System Improvement Charge Return.

Attachment H – Historic DCF and CAPM – Water 28
Historic barometer group DCF and CAPM average ROEs, including a linear trend line graph.

Attachment H – Water Barometer Group Calculation of a Current and 52 Week Average Dividend Yield 29
Water barometer companies are used to calculate a current DCF in the first chart. The second chart demonstrates the companies 52-week average DCF. A final average of the two calculations is also shown at the bottom.

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Multiple sources of the water barometer companies projected 5-year Earnings Per Share are used to calculate the Group Average Dividend Growth Estimate.

Introduction:

On September 20, 1991, the Commission initiated a rulemaking at L-00910061 pertaining to earnings disclosures by the public utilities subject to its jurisdiction. At that docket, the Commission stated that the submission of accurate, reliable, and complete earnings disclosure reports, at regular intervals, is essential to the fulfillment of the broad regulatory oversight responsibilities entrusted to the Commission by the Legislature in the Public Utility Code. The earnings disclosure regulations promulgated by the Commission were adopted October 1, 1992, and published January 23, 1993, at 23 Pa.B. 463. Based upon those regulations, codified at 52 Pa. Code, Chapter 71, a reporting format was developed and distributed to the jurisdictional fixed utilities of Pennsylvania.

All fixed utilities having jurisdictional revenues of $1,000,000 or more, for a calendar year, are required to file the report by March 31 of each year. Such reports are to be based upon the results of operations for the 12-month period ending December 31 of the prior year. Utilities having more than $10,000,000 in jurisdictional revenues are also required to file reports for the 12 months ending on March 31, June 30, and September 30 of each year.[1] On November 30, 2004, however, the Pennsylvania General Assembly signed into law Act 183 concerning alternative telecommunications regulation and broadband deployment. As a result of Act 183, the reporting requirements for the PUC jurisdictional telecommunications companies of Pennsylvania have been streamlined at section 3015(e) of the Public Utility Code. A quarterly earnings report is not listed among those reports now required of PUC jurisdictional telecommunications utilities in Pennsylvania and, therefore, this report does not address telephone company earnings.

The reports have been filed for the period ending December 31, 2024, at Docket No. M-2025-3052807.[2] The Finance Staff of the Bureau of Technical Utility Services has reviewed the reports and has prepared this summary report for public release. This report sets forth the achieved return on equity for each company, the last allowed return for that utility, a market return as determined through the analysis of the barometer group data and the most recent returns allowed, per industry, by the Pennsylvania Public Utility Commission and by other regulatory bodies. Where a utility has not filed a report, the reasons for not filing are indicated.

Questions pertaining to the preparation and contents of this Report should be directed to Mr. Marc Hoffer, Manager - Finance, Bureau of Technical Utility Services, at (717) 787-1869.

[1] Per Commission regulations at 52 Pa. Code § 71.3(a)(1), the major electric utilities are specifically identified by name rather than utilizing the $10,000,000 revenue threshold utilized by gas and water utilities.

[2] Columbia Gas of PA Inc., UGI Utilities, Inc. – Gas Division, and FirstEnergy Pennsylvania Electric Co. have rate filings at Docket Nos. R-2025-3053499, R-2024-3052716, and R-2024-3047068, respectively, and have filed a letter with the Secretary in place of a report in accordance with 52 Pa. Code § 71.4.

Attachment A

The equity return summaries that follow in Attachment A are, for each quarter;

ACTUAL

1. Based on actual results of operations

and

ADJUSTED

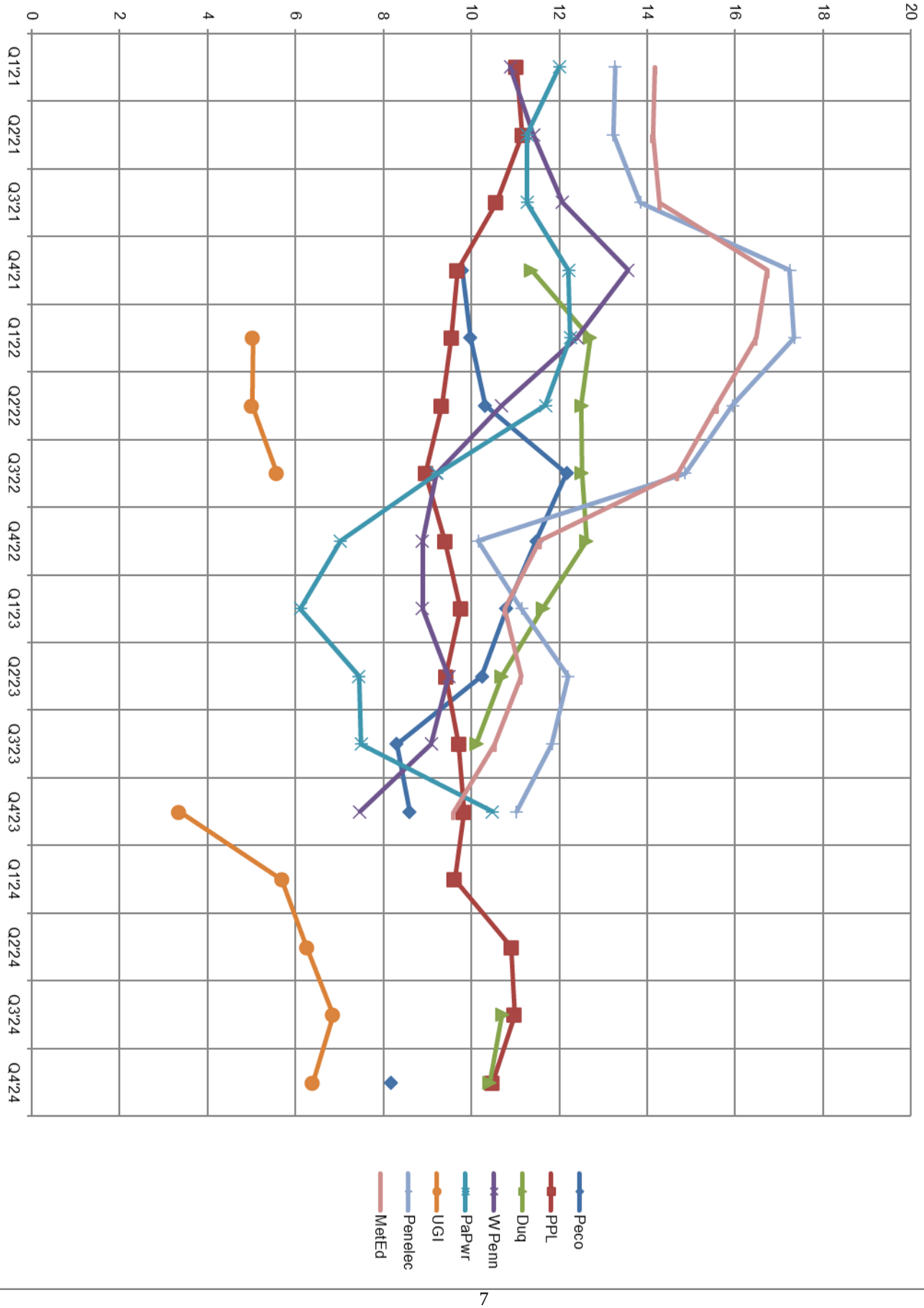
2. Based on company proposed pro forma and ratemaking adjustments

Attachment A

ELECTRIC UTILITIES
EQUITY RETURNS BY QUARTER

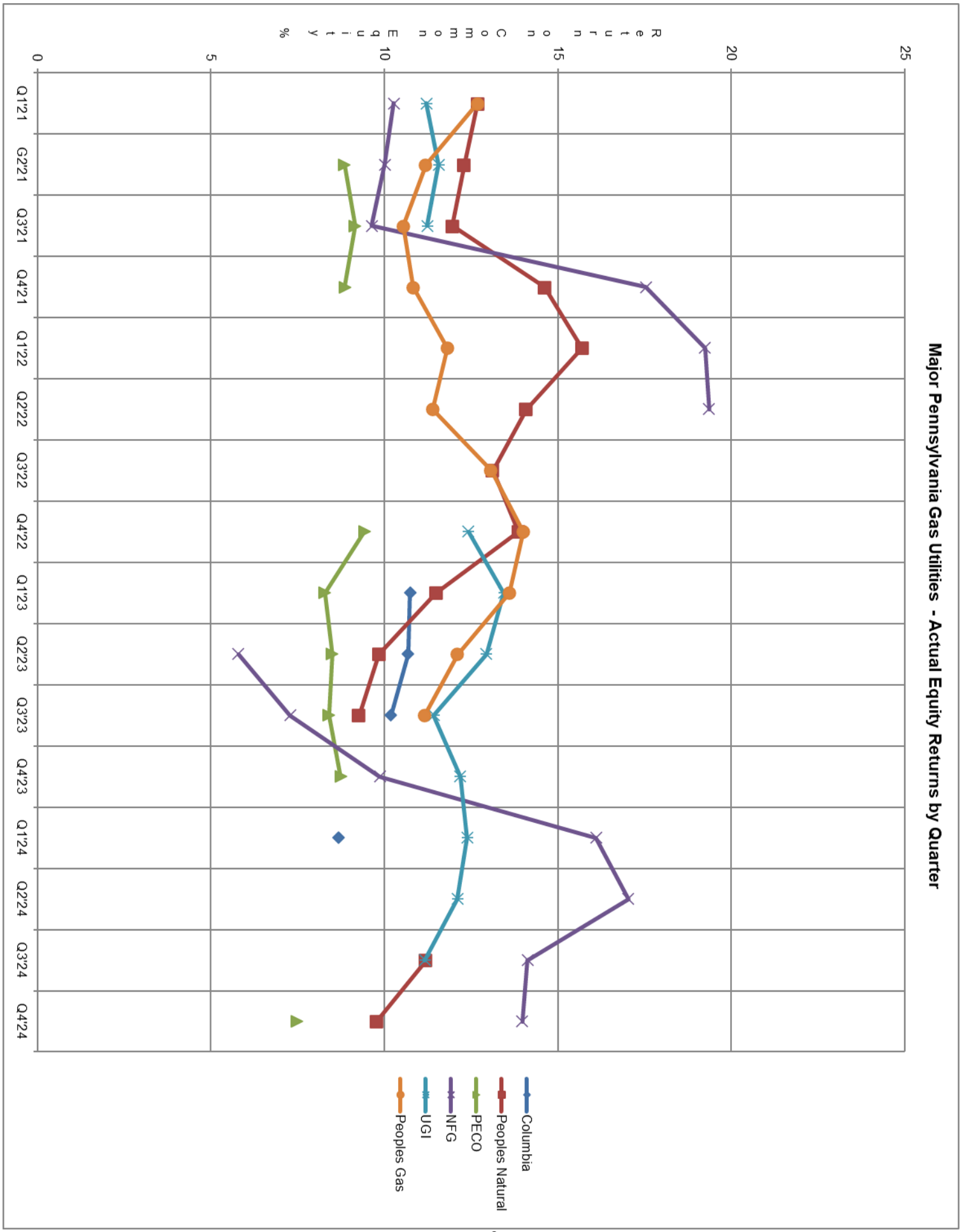
QTR END		Peco		PPL		Duq		W Penn		PaPwr		UGI		Penelec		MetEd	
		ACT	ADJ	ACT	ADJ	ACT	ADJ	ACT	ADJ	ACT	ADJ	ACT	ADJ	ACT	ADJ	ACT	ADJ
2018	1			12.53	11.36			10.35	9.08	9.03	8.08			11.84	9.93	12.77	11.38
	2			11.05	9.49			9.92	8.52	8.79	7.57			11.56	9.39	11.90	10.26
	3			11.19	9.83			11.41	6.74	10.30	5.80			13.97	8.44	14.46	9.62
	4	10.88	7.61	11.10	10.15	12.06	9.39	9.92	6.78	10.64	7.43			13.27	9.31	13.05	7.40
2019	1	12.65	7.93	10.10	8.96	12.58	9.73	9.08	6.62	9.14	7.61	7.05	5.22	12.03	8.07	12.54	7.66
	2	12.34	7.94	10.51	8.95	12.38	9.34	8.02	5.99	8.29	7.10	5.77	3.22	11.42	8.16	11.72	7.21
	3	12.49	7.96	10.61	8.99	13.88	9.33	9.90	7.87	9.28	7.76	6.20	2.04	11.26	8.78	12.25	7.77
	4	12.21	8.50	10.53	10.40	13.92	9.08	14.13	7.07	8.08	6.90	7.20	2.38	10.02	8.54	10.96	9.27
2020	1	11.31	8.35	10.84	11.20	12.66	8.31	9.82	5.54	5.06	6.71	5.43	2.26	7.24	8.74	7.20	8.31
	2	9.38	8.17	11.20	10.81	12.73	8.56	10.41	5.53	5.56	6.55	6.06	2.01	6.68	7.94	7.34	8.04
	3	9.62	8.56	11.14	11.20	12.32	8.08	10.22	5.42	5.62	6.74	7.76	0.41	7.87	8.75	7.64	8.37
	4	9.16	7.64	11.10	11.48	12.57	8.15	7.48	5.65	11.36	7.34			10.08	8.62	9.91	8.64
2021	1			11.03	11.76			10.89	6.64	12.01	7.01			13.27	8.96	14.19	9.44
	2			11.17	11.73			11.42	7.07	11.27	5.94			13.23	8.15	14.13	9.06
	3			10.57	10.65			12.08	7.91	11.27	5.91			13.85	8.67	14.29	9.38
	4	9.79	7.59	9.69	10.57	11.37	11.23	13.57	7.85	12.21	5.42			17.25	8.04	16.74	9.40
2022	1	9.98	6.99	9.55	9.49	12.71	10.91	12.40	6.99	12.26	5.30	5.03	4.93	17.35	7.83	16.48	9.40
	2	10.32	7.19	9.33	9.54	12.51	10.22	10.70	5.78	11.69	5.04	5.01	3.89	15.95	6.93	15.59	8.72
	3	12.17	7.42	8.97	9.14	12.52	9.74	9.21	4.43	9.23	4.35	5.58	0.65	14.87	5.88	14.70	7.57
	4	11.48	6.59	9.41	9.18	12.62	9.54	8.89	4.19	7.03	3.44			10.16	5.07	11.56	7.55
2023	1	10.80	6.47	9.76	9.36	11.63	9.53	8.89	5.32	6.11	4.01			11.15	6.88	10.77	8.25
	2	10.24	6.19	9.43	8.67	10.69	9.39	9.49	6.03	7.45	5.58			12.20	7.90	11.14	8.81
	3	8.30	5.48	9.72	8.12	10.12	8.89	9.09	5.96	7.50	5.76			11.84	7.79	10.54	8.60
	4	8.60	5.19	9.84	8.49			7.47	6.02	10.49	7.09	3.36	4.48	11.03	8.17	9.61	8.66
2024	1			9.63	8.22							5.70	2.03				
	2			10.92	9.17							6.26	1.11				
	3			10.99	9.46	10.71	9.16					6.86	1.70				
	4	8.17	4.22	10.49	7.23	10.42	9.38					6.40	1.41				

Major Pennsylvania Electric Utilities - Actual Equity Returns by Quarter



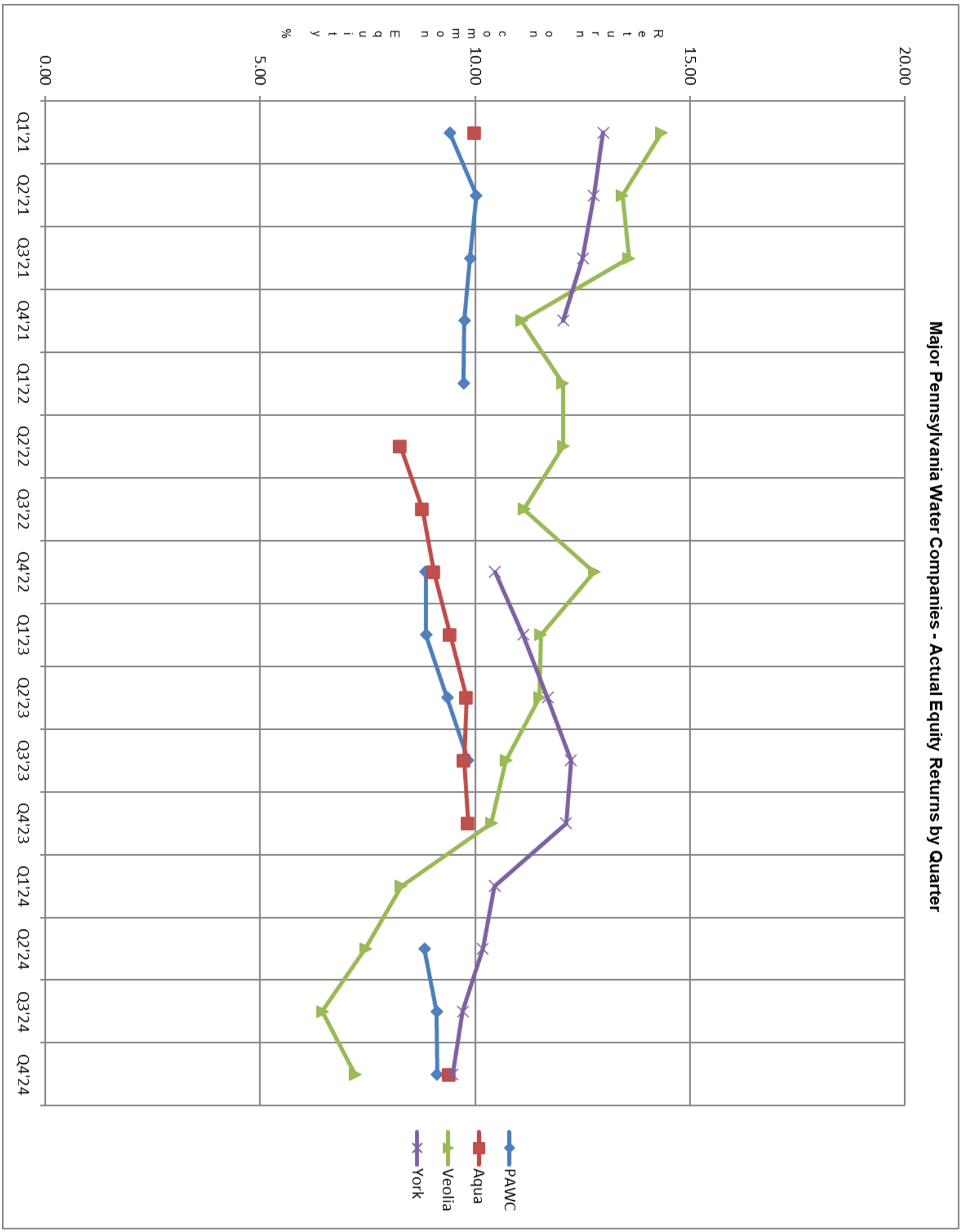
GAS UTILITIES
EQUITY RETURNS BY QUARTER

QTR		Columbia		Peoples Natural		PECO		NFG		UGI		Peoples Gas	
END		ACT	ADJ	ACT	ADJ	ACT	ADJ	ACT	ADJ	ACT	ADJ	ACT	ADJ
2018	1			11.42	7.00	12.65	9.77	14.40	10.20	12.82	7.90	14.02	10.17
	2			11.03	6.80	12.66	9.05	12.06	9.89	16.75	6.80	12.78	10.15
	3			10.21	7.43	12.54	8.36	12.52	10.12	18.69	8.04	13.03	10.20
	4	11.39	9.81			12.86	8.68	12.24	10.21			13.92	11.13
2019	1	12.76	10.22			13.68	9.06	11.83	10.93			14.10	10.71
	2	12.04	9.92			12.62	8.41	14.56	9.99			13.80	11.66
	3	11.77	9.85			12.40	8.31	14.17	9.75			14.02	11.63
	4	9.21	9.09	10.74	12.26	11.75	6.99	14.20	9.77			12.76	11.20
2020	1	8.42	9.11	12.34	12.34	10.84	7.68	11.82	9.92			11.40	11.07
	2			13.81	12.38	11.26	7.25	11.28	9.05			11.89	11.10
	3			14.60	12.77			10.39	8.25			11.82	11.50
	4			12.09	10.37			9.68	8.12			12.93	12.11
2021	1			12.69	10.43			10.27	8.47	11.22	7.70	12.69	11.76
	2			12.31	10.23	8.85	5.13	10.02	8.47	11.57	8.04	11.20	11.61
	3			11.97	10.27	9.16	5.27	9.64	8.45	11.24	6.97	10.56	11.38
	4			14.62	10.52	8.86	5.79	17.54	8.02			10.84	10.28
2022	1			15.71	10.93			19.24	7.88			11.83	12.09
	2			14.09	11.67			19.36	6.87			11.40	12.19
	3			13.13	10.30							13.08	11.31
	4			13.87	10.56	9.43	5.93			12.42	7.62	14.01	14.19
2023	1	10.75	10.30	11.50	9.02	8.29	6.05			13.45	8.33	13.61	12.68
	2	10.68	10.33	9.85	9.50	8.50	6.20	5.80	9.98	12.94	8.97	12.12	13.84
	3	10.19	10.72	9.28	8.17	8.41	6.01	7.29	9.58	11.43	8.27	11.17	14.22
	4					8.75	6.82	9.87	10.80	12.19	7.44		
2024	1	8.67	9.61					16.10	10.64	12.39	7.55		
	2							17.03	9.78	12.11	6.91		
	3			11.20	9.07			14.13	8.63	11.17	6.45		
	4			9.78	8.84	7.49	5.56	13.98	8.62				


Major Pennsylvania Gas Utilities - Actual Equity Returns by Quarter
Return on Common Equity %
0
5
10
15
20
25
Q1'21
Q2'21
Q3'21
Q4'21
Q1'22
Q2'22
Q3'22
Q4'22
Q1'23
Q2'23
Q3'23
Q4'23
Q1'24
Q2'24
Q3'24
Q4'24
Columbia
Peoples Natural
PECO
NFG
UGI
Peoples Gas

WATER UTILITIES
EQUITY RETURNS BY QUARTER

QTR		PAWC		Aqua		Veolia		York	
END		ACT	ADJ	ACT	ADJ	ACT	ADJ	ACT	ADJ
2018	1	9.55	8.97	10.94	8.41				
	2	10.27	9.65						
	3	11.03	9.48						
	4	10.08	9.03					10.70	10.30
2019	1	9.82	8.87					11.60	11.60
	2	9.72	8.90	9.84	9.04	10.78	10.36	11.80	11.80
	3	9.13	8.41	10.69	8.84	11.55	11.75	12.00	12.00
	4	8.71	8.09	10.33	8.24	11.80	12.15	12.00	9.80
2020	1	8.74	7.56	10.47	8.31	11.30	11.30	12.39	12.39
	2			10.81	8.57	10.72	10.69	12.51	12.51
	3			10.33	8.55	11.13	10.69	13.76	13.76
	4	8.90	8.15	9.89	8.30	13.98	10.17	13.42	9.94
2021	1	9.41	8.90	9.99	8.38	14.34	10.48	12.98	9.74
	2	10.03	9.28			13.43	9.83	12.76	9.66
	3	9.89	8.65			13.58	9.07	12.51	9.32
	4	9.75	8.05			11.08	9.75	12.05	8.86
2022	1	9.73	7.82			12.04	9.68		
	2			8.26	8.91	12.05	9.79		
	3			8.78	8.85	11.14	9.30		
	4	8.85	8.97	9.04	8.88	12.77	9.49	10.47	10.57
2023	1	8.86	8.90	9.42	8.48	11.53	8.98	11.12	11.12
	2	9.35	8.89	9.80	8.52	11.50	8.91	11.69	11.69
	3	9.84	8.93	9.74	8.39	10.72	8.42	12.23	12.23
	4			9.84	8.35	10.38	7.64	12.12	8.16
2024	1					8.28	6.49	10.46	7.99
	2	8.82	8.56			7.46	5.70	10.18	8.00
	3	9.11	8.49			6.45	5.42	9.72	7.31
	4	9.12	8.44	9.40	9.29	7.21	5.36	9.48	7.10


Major Pennsylvania Water Companies - Actual Equity Returns by Quarter
Return on Common Equity %
20.00
15.00
10.00
5.00
0.00
Q1'21
Q2'21
Q3'21
Q4'21
Q1'22
Q2'22
Q3'22
Q4'22
Q1'23
Q2'23
Q3'23
Q4'23
Q1'24
Q2'24
Q3'24
Q4'24
PAWC
Aqua
Veolia
York

Attachment B includes:

A. Overall Returns on rate base
1. Actual
2. Company proposed pro forma and ratemaking adjustments

and

B. Equity Returns
1. Actual
2. Company proposed pro forma and ratemaking adjustments

Summary of Returns
For the Year Ended December 31, 2024

COMPANY NAME	OVERALL RETURN ACTUAL	OVERALL RETURN ADJ	EQUITY RETURN ACTUAL	EQUITY RETURN ADJ	ROE AUTH	YEAR AUTH
ELECTRIC						
Major Electric Utilities						
PECO Energy - Electric Operations	6.31	4.10	8.17	4.22	Settled	2024
PPL Electric Utilities Corp.	7.99	6.06	10.49	7.23	Settled	2015
Duquesne Light Company	7.89	7.24	10.42	9.38	Settled	2024
West Penn Power Company*					Settled	2024
Pennsylvania Power Company*					Settled	2024
UGI Utilities, Inc. - Electric Division	5.57	3.18	6.40	1.41	Settled	2023
Pennsylvania Electric Company*					Settled	2024
Metropolitan Edison Company *					Settled	2024
Over $1,000,000						
Revenues						
Pike County Light & Power Co.	6.21	6.21	5.98	5.98	Settled	2021
Citizens Electric Company	6.30	8.03	6.58	8.54	Settled	2022
Wellsboro Electric Company	4.59	4.59	4.67	4.67	9.31	2020
GAS						
$10,000,000 Revenues						
Columbia Gas of PA, Inc.*					Settled	2024
Peoples Natural Gas Company LLC	7.14	6.31	9.78	8.84	Settled	2024
PECO Energy - Gas Operations	6.06	4.93	7.49	5.56	Settled	2024
National Fuel Gas Distribution Co.	10.04	7.11	13.98	8.62	Settled	2023
UGI Utilities, Inc. – Gas Division*					Settled	2022
Valley Energy Inc. of PA	3.89	3.97	3.40	3.51	Settled	2022
$1,000,000 to $10,000,000						
Revenues						
Pike County Light & Power Co.	2.39	2.39	-1.16	-1.16	Settled	2021
Leatherstocking Gas Company	2.15	2.15	-3.47	-3.47	Settled	2023
North East Heat and Light Company	4.25	4.25	4.35	4.37	11.00	2008
WATER						
$10,000,000 Revenues						
PA American Water Company	7.08	6.70	9.12	8.44	9.45	2024
Aqua Pennsylvania	7.03	6.92	9.40	9.29	Settled	2025
York Water Company	7.30	6.00	9.48	7.10	Settled	2023
Veolia Water Pennsylvania, Inc.	5.90	4.94	7.21	5.36	Settled	2024
$1,000,000 to $10,000,000						
Revenues						
Newtown Artesian Water Co.	5.56	3.35	6.29	2.52	Settled	2025
Columbia Water Company	6.27	6.27	6.86	6.86	9.75	2024
York Water Company – Wastewater	1.30	0.40	-0.30	-2.10	Settled	2023
Community Utilities – Water	2.56	2.56	0.44	0.44	Settled	2022
Community Utilities – Wastewater	4.12	4.12	3.24	3.24	Settled	2022
CAN DO Inc. – Water	1.99	1.99	2.46	2.46	Settled	2024
CAN DO Inc. – Wastewater	22.76	22.76	25.93	25.93	Settled	2024

*Columbia Gas of PA Inc., UGI Utilities, Inc. – Gas Division, and FirstEnergy Pennsylvania Electric Co. have rate filings at Docket Nos. R-2025-3053499, R-2024-3052716, and R-2024-3047068, respectively, and have filed a letter with the Secretary in place of a report in accordance with 52 Pa. Code § 71.4.

ALLOWED RATES OF RETURN ON COMMON EQUITY

This is a historical chart that shows the most recent rate cases for select companies in electric, gas, and water. A docket number followed by their final return on equity and year is also given.

ELECTRIC	**Docket Number**	**ROE (%)**	**Year**
Recent PA PUC Allowed			
UGI Utilities, Inc. – Electric	R-2022-3037368	Settled	2023
Duquesne Light Company	R-2024-3046523	Settled	2024
PECO Energy – Electric	R-2024-3046931	Settled	2024
PPL Electric Utilities Corp.	R-2015-2469275	Settled	2015
Pennsylvania Electric Company	R-2024-3047068	Settled	2024
Metropolitan Edison Company	R-2024-3047068	Settled	2024
Pennsylvania Power Company	R-2024-3047068	Settled	2024
West Penn Power Company	R-2024-3047068	Settled	2024
Current Market Indicated ROE as calculated by the Bureau of Technical Utility Services.			**9.17-11.23**

GAS			
Recent PA PUC Allowed			
National Fuel Gas Distribution Corp.	R-2022-3035730	Settled	2023
Columbia Gas of Pennsylvania, Inc.	R-2024-3046519	Settled	2024
PECO Energy – Gas	R-2024-3046932	Settled	2024
UGI Utilities, Inc. – Gas	R-2021-3030218	Settled	2022
Peoples Natural Gas Company	R-2023-3044549	Settled	2024
Current Market Indicated ROE as calculated by the Bureau of Technical Utility Services.			**8.92-12.05**

WATER			
Recent PA PUC Allowed			
Columbia Water	R-2023-3040258	9.75	2024
PA American Water	R-2023-3043189	9.45	2024
York Water	R-2022-3031340	Settled	2023
Aqua Pennsylvania	R-2024-3047822	Settled	2025
Veolia Water Pennsylvania	R-2024-3045192	Settled	2024
Current Market Indicated ROE as calculated by the Bureau of Technical Utility Services.			**7.25-12.59**

Distribution System Improvement Charge (DSIC) Eligible Utilities
Return on Equity (ROE) Summary

	Utility Adjusted ROE[3] (%)	Commission Approved ROE[4] (%)
ELECTRIC		
PECO Energy – Electric Operations	4.22	10.00
PPL Electric Utilities Corp.	7.23	10.00
Duquesne Light Company	9.38	10.00
West Penn Power Company*		10.00
Pennsylvania Power Company*		10.00
Pennsylvania Electric Company*		10.00
Metropolitan Edison Company*		10.00
UGI Utilities, Inc.- Electric Division	1.41	10.00
Pike County Light & Power Co.	5.98	10.00
GAS		
Columbia Gas of PA, Inc.*		10.15
Peoples Natural Gas Company LLC	8.84	10.15
PECO Energy – Gas Operations	5.56	10.15
UGI Utilities, Inc. – Gas Division*		10.15
Pike County Light & Power Co.	-1.16	10.15
National Fuel Gas Distribution Corp	8.62	10.15
WATER		
PA American Water Company	8.44	9.45
PA American – Wastewater	8.44	9.45
AQUA Pennsylvania	9.29	9.75
AQUA Pennsylvania – Wastewater	9.29	9.75
York Water Company	7.10	9.75
Veolia Water Pennsylvania, Inc.	5.36	9.75
Columbia Water Company	6.86	9.75
Newtown Artesian Water	2.52	9.75

* Columbia Gas of PA Inc., UGI Utilities, Inc. – Gas Division, and FirstEnergy Pennsylvania Electric Co. have rate filings at Docket Nos. R-2025-3053499, R-2024-3052716, and R-2024-3047068, respectively, and have filed a letter with the Secretary in place of a report in accordance with 52 Pa. Code § 71.4.

3 Each utility lists adjustments on Schedule B of their quarterly financial report.
4 The ROE is approved in a utility's most recent fully litigated base rate proceeding for hich a final order was entered not more than two years prior to the effective date of the DSIC. If more than two years have elapsed between the entry of a final order and the DSIC effective date, the ROE is from this report. If the base rate proceeding is settled, without a stipulated ROE, the ROE is from this report.

Explanation of Discounted Cash Flow (DCF) and Capital Asset Pricing Model (CAPM)

Barometer Group Criteria

The criteria used for determining the industry barometer groups used to calculate ROEs in this report are as follows:

- 50% or more of the company's assets must be related to the jurisdictional utility industry;
- The company's stock must be publicly traded and must have at least three years of earnings history;
- Companies targeted by merger and acquisition (M&A) activity will be excluded; companies involved in M&A activity may be excluded;
- Investment information for the company must be available to the Commission from more than one source;
- The barometer group companies must have an investment grade credit rating (S&P BBB- or better, Moody's Baa3 or better); and
- Geographic Regions:
  EDCs: *Value Line* Investment Survey's East, Central, and West Group Electric Utility companies;
  NGDCs: *Value Line* Investment Survey's Natural Gas Utility industry group companies;
  Water/Wastewater: *Value Line* Investment Survey's Water Utility industry group companies.

The barometer group companies are reviewed by staff on a quarterly basis and make any changes to these companies based upon the criteria above.

ROE Calculations

The Commission consistently uses the DCF model to determine the appropriate cost of equity for utilities. In this report, the DSIC ROE is calculated using two DCF models.

TUS uses the following formula to calculate the current dividend DCF: $K = D_1/P_0 + G$

TUS uses the following formula to calculate the 52-week average dividend DCF: $K = D_0/P_a + G$

Definitions:

K	=	Cost of equity
D_1	=	Dividend expected during the year
	=	$D_0 + ½g$
D_0	=	Latest indicated dividend, obtained from Yahoo! Finance
g	=	Expected 5-year dividend growth rate of barometer group obtained from Value Line Investment Survey.
P_0	=	Current price of the stock, obtained from Yahoo! Finance
P_a	=	Average of high and low stock price over the latest 52-week period, obtained from Yahoo! Finance
G	=	Average of 5-year expected earnings growth rate forecasts obtained from Value Line, Zacks Investment Survey, and S&P Capital IQ.

The CAPM uses the yield of a risk-free interest-bearing obligation plus a rate of return premium that is proportional to the systematic risk of an investment.

TUS uses the following formula to calculate CAPM: $K = R_f + \beta(R_m - R_f)$

Three components are necessary to calculate the CAPM cost of equity:

β	=	Beta, a measure of systematic risk for each stock
R_f	=	The risk-free rate of return, 10-year U.S. Treasury yields are used for R_f. Yields are taken from the previous two quarters and forecasted next four quarters.
R_m	=	Total return of the equity market as determined by Kroll

The Commission determines the ROE used for DSIC purposes based on the range of reasonableness from the DCF barometer group data, CAPM data, recent ROE adjudicated by the Commission, and informed judgment.

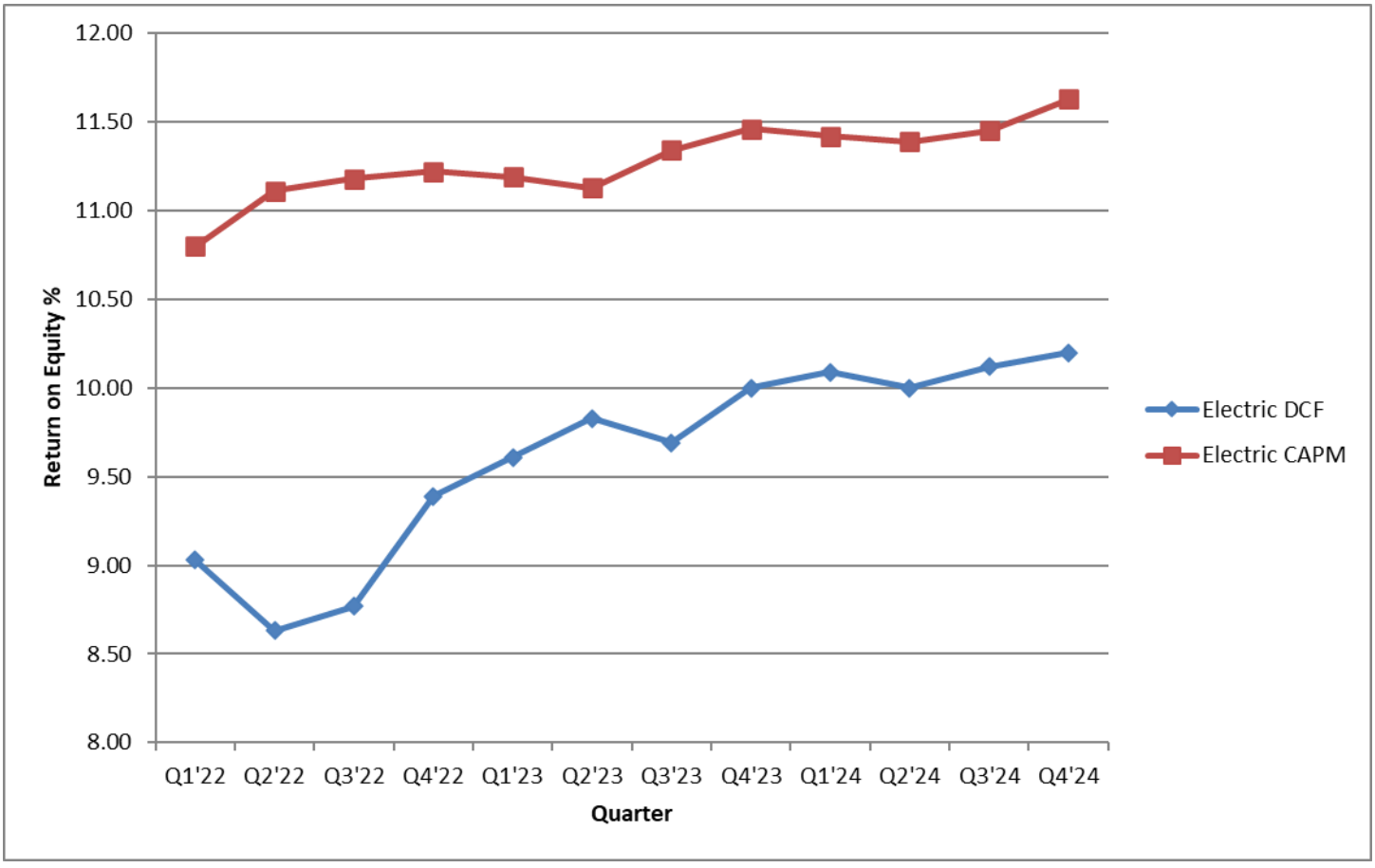
The market indicated common equity cost rate range consists of data used from the barometer groups and is based on a series of calculations to average the DCF methods.

Market Based Returns on Common Equity[1]	
April 7, 2025	
Electric Company Barometer Group	
	Cost Rates
	%
(1) Current DCF:	10.23
(2) 52-Week Average DCF:	10.18
(3) Overall DCF ((1) + (2)) / 2 :	10.20
(4) Market Indicated Common Equity Cost Rate Range:	9.17-11.23
(5) CAPM Check of DCF Reasonableness:	11.63
(6) Recent Commission Approved ROEs[3]:	*
*None within the last two years	
(7) Distribution System Improvement Charge (DSIC) Return[4]:	**10.00%**
[1] As calculated by the Bureau of Technical Utility Services	
[2] Standard Deviation of 58 DCF observations	
[3] Base rate case ROEs within last two years, fully litigated or stipulated for DSIC purposes	
[4] Commission authorized Return on Equity (ROE) for DSIC purposes	
Any questions concerning DSIC should be directed to Rich Layton	
of the Bureau of Technical Utility Services at (717) 214-9117.	

Historic Electric Industry Barometer Group DCF and CAPM Average ROEs

Electric		
	DCF	CAPM
Q1'22	9.03	10.80
Q2'22	8.63	11.11
Q3'22	8.77	11.18
Q4'22	9.39	11.22
Q1'23	9.61	11.19
Q2'23	9.83	11.13
Q3'23	9.69	11.34
Q4'23	10.00	11.46
Q1'24	10.09	11.42
Q2'24	10.00	11.39
Q3'24	10.12	11.45
Q4'24	10.20	11.63

Chart of Historic Electric Industry DCF and CAPM Average ROEs



Barometer electric companies are used to calculate a current DCF in the first chart. The second chart demonstrates the companies' 52-week average DCF. A final average of the two calculations is also shown at the bottom.

Electric Company Barometer Group
Calculation of a Current Dividend Yield

	Closing Market Price (Po) 4/7/2025 ($)	Latest Indicated Dividend (Do) ($)	Ind. Div. Plus 1/2 Div. Growth Rate (D1) ($)	Current Dividend Yield(D1/Po) (%)	DCF (%)
Alliant Energy Corp	59.81	2.03	2.09	3.50	10.00
Ameren Corp	94.34	2.84	2.93	3.11	9.80
American Electric Power	101.57	3.72	3.82	3.76	10.26
Avista Corp	39.56	1.96	2.00	5.05	10.71
CenterPoint Energy	35.50	0.88	0.91	2.55	9.88
CMS Energy Corp	70.94	2.17	2.22	3.14	10.13
Consolidated Edison	105.40	3.40	3.47	3.29	9.13
Dominion Energy	50.83	2.67	2.68	5.27	8.77
DTE Energy Company	127.95	4.36	4.46	3.48	11.47
Duke Energy Company	116.86	4.18	4.25	3.64	9.85
Edison International	53.62	3.31	3.41	6.36	13.94
Entergy Corp.	79.34	2.40	2.47	3.11	12.30
Evergy Inc	64.36	2.67	2.76	4.29	10.60
Eversource Energy	55.56	3.01	3.10	5.58	11.16
Exelon Corporation	44.69	1.60	1.60	3.58	9.63
FirstEnergy Corp	38.71	1.78	1.83	4.72	10.89
IDACORP, Inc..	113.75	3.44	3.53	3.11	10.71
MGE Energy, Inc.	87.02	1.80	1.86	2.14	9.14
NextEra Energy, Inc.	65.06	2.27	2.38	3.65	11.46
NorthWestern Corp	54.72	2.64	2.66	4.86	10.37
OGE Energy Corp	42.24	1.69	1.72	4.06	10.23
Otter Tail Corp	75.27	2.10	2.17	2.89	9.24
PPL Corporation	33.52	1.09	1.09	3.24	10.42
TXNM Energy Inc.	49.78	1.63	1.67	3.36	8.64
Pinnacle West Capital Corp	89.62	3.58	3.61	4.02	8.92
Portland General Electric Co.	41.58	2.00	2.06	4.94	9.91
Public Service Enterprise Group	77.13	2.52	2.60	3.37	9.95
Southern Company	87.22	2.88	2.93	3.36	9.80
Xcel Energy Inc.	67.06	2.28	2.35	3.50	10.49
Group Average	69.76	2.51	2.57	3.83	10.27
Group Average G				6.40	
DCF				**10.23**	

Electric Company Barometer Group 52-week Average Dividend Yield Calculation						
	High	Low	Average (Pa)	Latest Indicated Dividend (Do)	Average Dividend Yield (Do/Pa)	DCF
	($)	($)	($)	($)	(%)	(%)
Alliant Energy Corp	66.54	47.23	56.89	2.03	3.57	10.07
Ameren Corp	104.10	69.39	86.75	2.84	3.27	9.97
American Electric Power	110.48	79.16	94.82	3.72	3.92	10.42
Avista Corp	43.09	33.00	38.05	1.96	5.15	10.81
CenterPoint Energy	37.70	25.41	31.56	0.88	2.79	10.12
CMS Energy Corp	76.45	56.61	66.53	2.17	3.26	10.25
Consolidated Edison	114.87	87.28	101.08	3.40	3.36	9.20
Dominion Energy	61.97	46.62	54.30	2.67	4.92	8.42
DTE Energy Company	140.39	103.06	121.73	4.36	3.58	11.57
Duke Energy Company	125.27	92.75	109.01	4.18	3.83	10.04
Edison International	88.77	49.06	68.92	3.31	4.80	12.38
Entergy Corp.	88.38	50.19	69.29	2.40	3.46	12.65
Evergy Inc	70.30	49.55	59.93	2.67	4.46	10.76
Eversource Energy	69.01	54.54	61.78	3.01	4.87	10.45
Exelon Corporation	48.11	34.01	41.06	1.60	3.90	9.94
FirstEnergy Corp	44.97	36.81	40.89	1.78	4.35	10.52
IDACORP, Inc..	120.84	88.70	104.77	3.44	3.28	10.89
MGE Energy, Inc.	109.22	72.27	90.75	1.80	1.98	8.98
NextEra Energy, Inc.	86.10	61.31	73.71	2.27	3.08	10.88
NorthWestern Corp	59.52	47.48	53.50	2.64	4.93	10.45
OGE Energy Corp	46.91	32.37	39.64	1.69	4.26	10.44
Otter Tail Corp	100.84	71.66	86.25	2.10	2.43	8.78
PPL Corporation	36.64	25.93	31.29	1.09	3.48	10.66
TXNM Energy Inc.	55.50	35.35	45.43	1.63	3.59	8.86
Pinnacle West Capital Corp	96.50	70.72	83.61	3.58	4.28	9.18
Portland General Electric Co.	49.85	40.05	44.95	2.00	4.45	9.42
Public Service Enterprise Group	95.22	64.03	79.63	2.52	3.16	9.75
Southern Company	94.45	67.53	80.99	2.88	3.56	10.00
Xcel Energy Inc.	73.38	51.97	62.68	2.28	3.64	10.62
Group Average	79.84	56.69	68.27	2.51	3.78	10.22
Group Average G					6.40	
DCF					**10.18**	
		Average of Current and 52-Week			**10.20**	

Multiple sources of the Barometer companies' projected 5-year Earnings Per Share are used to calculate the Group Average Dividend Growth Estimate.

Development of a Representative Dividend Growth Rate
for the Barometer Group of Electric Companies

		5 Year Forecast				
	Value Line DPS (%)	Value Line EPS (%)	Zack's EPS (%)	S&P EPS (%)	Average Earnings Growth (%)	Growth Estimate (%)
Alliant Energy Corp	6.00	6.00	6.70	6.81	6.50	6.50
Ameren Corp	6.50	6.50	6.70	6.88	6.69	6.69
American Electric Power	5.50	6.50	6.30	6.69	6.50	6.50
Avista Corp	4.00	5.00	6.10	5.88	5.66	5.66
CenterPoint Energy	6.00	6.50	7.50	7.98	7.33	7.33
CMS Energy Corp	5.00	6.00	7.70	7.27	6.99	6.99
Consolidated Edison	4.00	6.00	5.60	5.91	5.84	5.84
Dominion Energy	0.50	3.50	13.60	13.49	10.20	3.50
DTE Energy Company	4.50	8.50	7.60	7.87	7.99	7.99
Duke Energy Company	3.50	6.00	6.30	6.32	6.21	6.21
Edison International	6.00	6.50	8.50	7.74	7.58	7.58
Entergy Corp.	5.50	3.00	9.50	8.88	7.13	9.19
Evergy Inc	7.00	7.50	5.70	5.72	6.31	6.31
Eversource Energy	6.00	5.50	5.70	5.54	5.58	5.58
Exelon Corporation	NA	NA	6.00	6.09	6.05	6.05
FirstEnergy Corp	5.50	5.50	6.90	6.11	6.17	6.17
IDACORP, Inc..	5.50	6.00	8.50	8.31	7.60	7.60
MGE Energy, Inc.	6.50	7.00	NA	NA	7.00	7.00
NextEra Energy, Inc.	9.50	8.50	7.80	7.11	7.80	7.80
NorthWestern Corp	1.50	4.50	6.10	5.94	5.51	5.51
OGE Energy Corp	3.00	6.50	6.10	5.92	6.17	6.17
Otter Tail Corp	7.00	4.50	NA	8.20	6.35	6.35
PPL Corporation	-0.50	7.50	6.80	7.22	7.17	7.17
TXNM Energy Inc.	5.50	4.00	3.00	6.55	4.52	5.28
Pinnacle West Capital Corp	1.50	4.00	2.10	5.80	3.97	4.90
Portland General Electric Co.	5.50	5.50	3.40	6.01	4.97	4.97
Public Service Enterprise Group	6.00	6.00	7.20	6.56	6.59	6.59
Southern Company	3.50	6.50	6.50	6.33	6.44	6.44
Xcel Energy Inc.	6.00	6.50	6.90	7.56	6.99	6.99
Group Average	4.86	5.91	6.70	7.02	6.54	6.44
USE						**6.40**

Sources: Value Line, April 8, 2025 (www.valueline.com)
Zacks, April 8, 2025 (www.zacks.com)
Yahoo!, April 8, 2025 (http://finance.yahoo.com/)
S&P Capital IQ, April 8, 2025 (www.spglobal.com)
* NA signifies that a forecast was not available

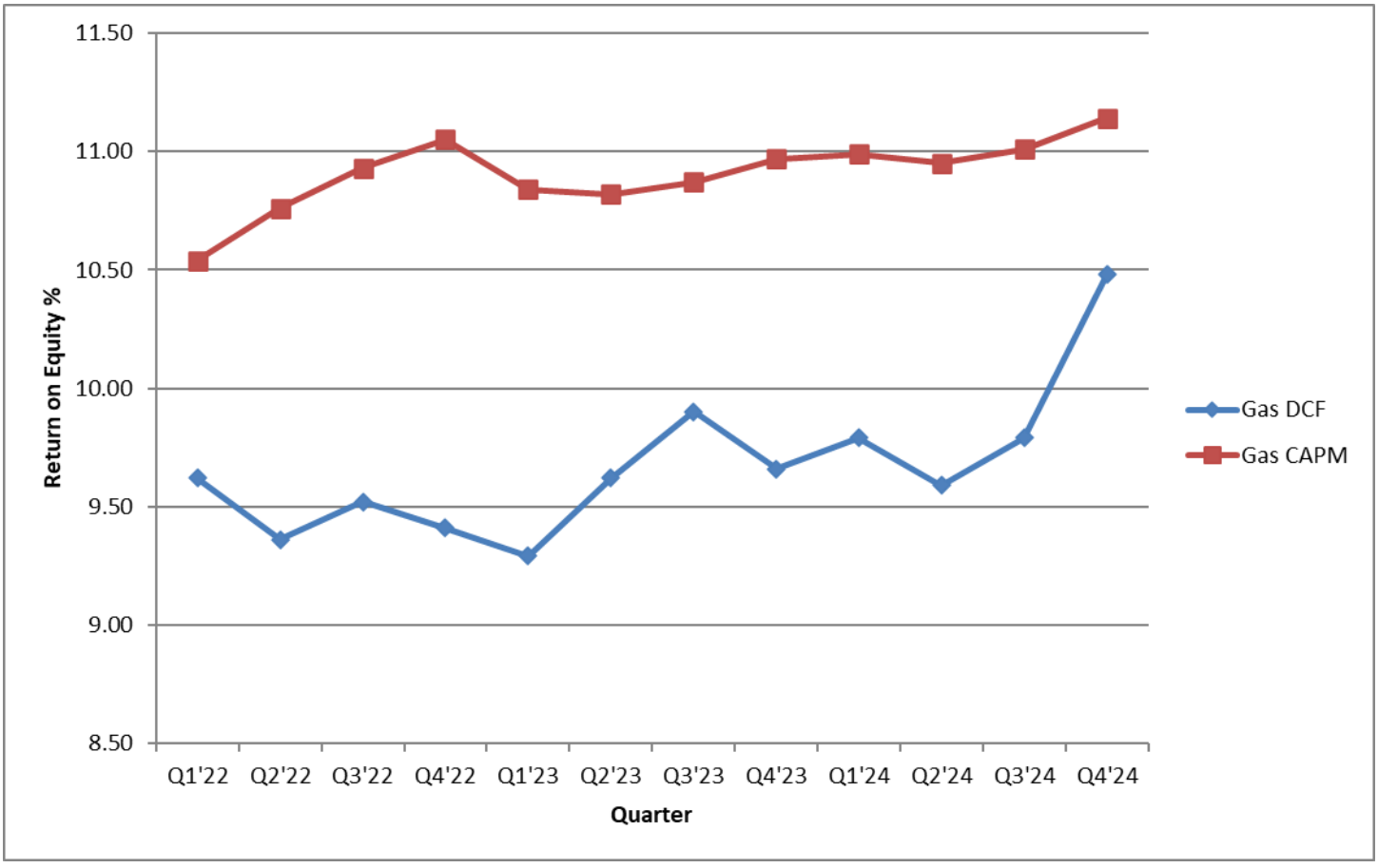
The market indicated common equity cost rate range consists of data used from the barometer groups and is based on a series of calculations to average the DCF methods.

Market Based Returns on Common Equity[1]	
April 7, 2025	
Gas Distribution Company Barometer Group	
	Cost Rates
	%
(1) Current DCF:	10.46
(2) 52-Week Average DCF:	10.51
(3) Overall DCF ((1) + (2)) / 2 :	10.48
(4) Market Indicated Common Equity Cost Rate Range:	8.92-12.05
@ 1 standard deviation around the mean.[2]	
(5) CAPM Check of DCF Reasonableness:	11.14
(6) Recent Commission Approved ROEs[3]:	*
*None within the last two years	
(7) Distribution System Improvement Charge (DSIC) Return[4]:	**10.15%**
[1] As calculated by the Bureau of Technical Utility Services	
[2] Standard Deviation of 16 DCF observations	
[3] Base rate case ROEs within last two years, fully litigated or stipulated for DSIC	
[4] Commission authorized Return on Equity (ROE) for DSIC purposes	
Any questions concerning DSIC should be directed to Rich Layton	
of the Bureau of Technical Utility Services at (717) 214-9117.	

Historic Gas Industry DCF and CAPM Average ROEs

Gas		
	DCF	CAPM
Q1'22	9.62	10.54
Q2'22	9.36	10.76
Q3'22	9.52	10.93
Q4'22	9.41	11.05
Q1'23	9.29	10.84
Q2'23	9.62	10.82
Q3'23	9.90	10.87
Q4'23	9.66	10.97
Q1'24	9.79	10.99
Q2'24	9.59	10.95
Q3'24	9.79	11.01
Q4'24	10.48	11.14

Graph of Historic Gas Industry DCF and CAPM Average ROEs



Barometer gas companies are used to calculate a current DCF in the first chart. The second chart demonstrates the companies' 52-week average DCF. A final average of the two calculations is also shown at the bottom.

Gas Company Barometer Group
Calculation of a Current Dividend Yield

	Closing Market Price (Po) 4/7/2025 ($)	Latest Indicated Dividend (Do) ($)	Ind. Div. Plus 1/2 Div. Growth Rate (D1) ($)	Current Dividend Yield(D1/Po) (%)	DCF (%)
Atmos Energy	145.06	3.48	3.60	2.48	9.39
Chesapeake Utilities Corporation	126.28	2.56	2.66	2.10	8.68
New Jersey Resources	46.94	1.80	1.85	3.93	10.23
NiSource Inc.	37.16	1.12	1.16	3.11	11.06
Northwest Natural Gas	40.06	1.96	1.96	4.90	11.40
ONE Gas, Inc.	71.91	2.68	2.71	3.77	8.35
Southwest Gas	66.91	2.48	2.55	3.81	13.56
Spire Inc.	73.73	3.14	3.20	4.34	10.70
Group Average	76.01	2.40	2.46	3.56	10.42
Group Average G				6.90	
DCF				**10.46**	

Gas Company Barometer Group
52-week Average Dividend Yield Calculation

	High ($)	Low ($)	Average (Pa) ($)	Latest Indicated Dividend (Do) ($)	Average Dividend Yield (Do/Pa) (%)	DCF (%)
Atmos Energy	157.62	110.97	134.30	3.48	2.59	9.50
Chesapeake Utilities Corporation	134.86	98.32	116.59	2.56	2.20	8.77
New Jersey Resources	51.95	40.62	46.29	1.80	3.89	10.19
NiSource Inc.	41.45	26.26	33.86	1.12	3.31	11.25
Northwest Natural Gas	44.25	34.82	39.54	1.96	4.96	11.46
ONE Gas, Inc.	78.89	58.31	68.60	2.68	3.91	8.48
Southwest Gas	80.29	64.31	72.30	2.48	3.43	13.18
Spire Inc.	79.81	57.27	68.54	3.14	4.58	10.94
Group Average	83.64	61.36	72.50	2.40	3.61	10.47
Group Average G					6.90	
DCF					**10.51**	
		Average of Current and 52-Week			**10.48**	

Multiple sources of the Barometer companies' projected 5-year Earnings Per Share are used to calculate the Group Average Dividend Growth Estimate.

Development of a Representative Dividend Growth Rate for the Barometer Group of Gas Companies						
	5 Yr Forecast					
	Value Line DPS (%)	Value Line EPS (%)	Zack's EPS (%)	S&P EPS (%)	Average Earnings Growth (%)	Growth Estimate (%)
Atmos Energy	7.00	6.00	7.20	7.52	6.91	6.91
Chesapeake Utilities Corporation	7.50	5.00	NA	8.15	6.58	6.58
New Jersey Resources	5.00	5.00	NA	7.60	6.30	6.30
NiSource Inc.	6.50	8.00	7.90	7.94	7.95	7.95
Northwest Natural Gas	0.50	6.50	NA	6.50	6.50	6.50
ONE Gas, Inc.	2.50	4.00	5.90	3.83	4.58	4.58
Southwest Gas	5.50	10.00	9.50	12.60	10.70	9.75
Spire Inc.	4.00	4.50	6.50	8.08	6.36	6.36
Group Average	4.81	6.13	7.40	7.78	6.98	6.86
USE						**6.90**
Sources:	Value Line, April 8, 2025 (www.valueline.com)					
	Zacks, April 8, 2025 (www.zacks.com)					
	Yahoo!, April 8, 2025 (http://finance.yahoo.com/)					
	S&P Capital IQ, April 8, 2025 (www.spglobal.com)					
	* NA signifies that a forecast was not available					

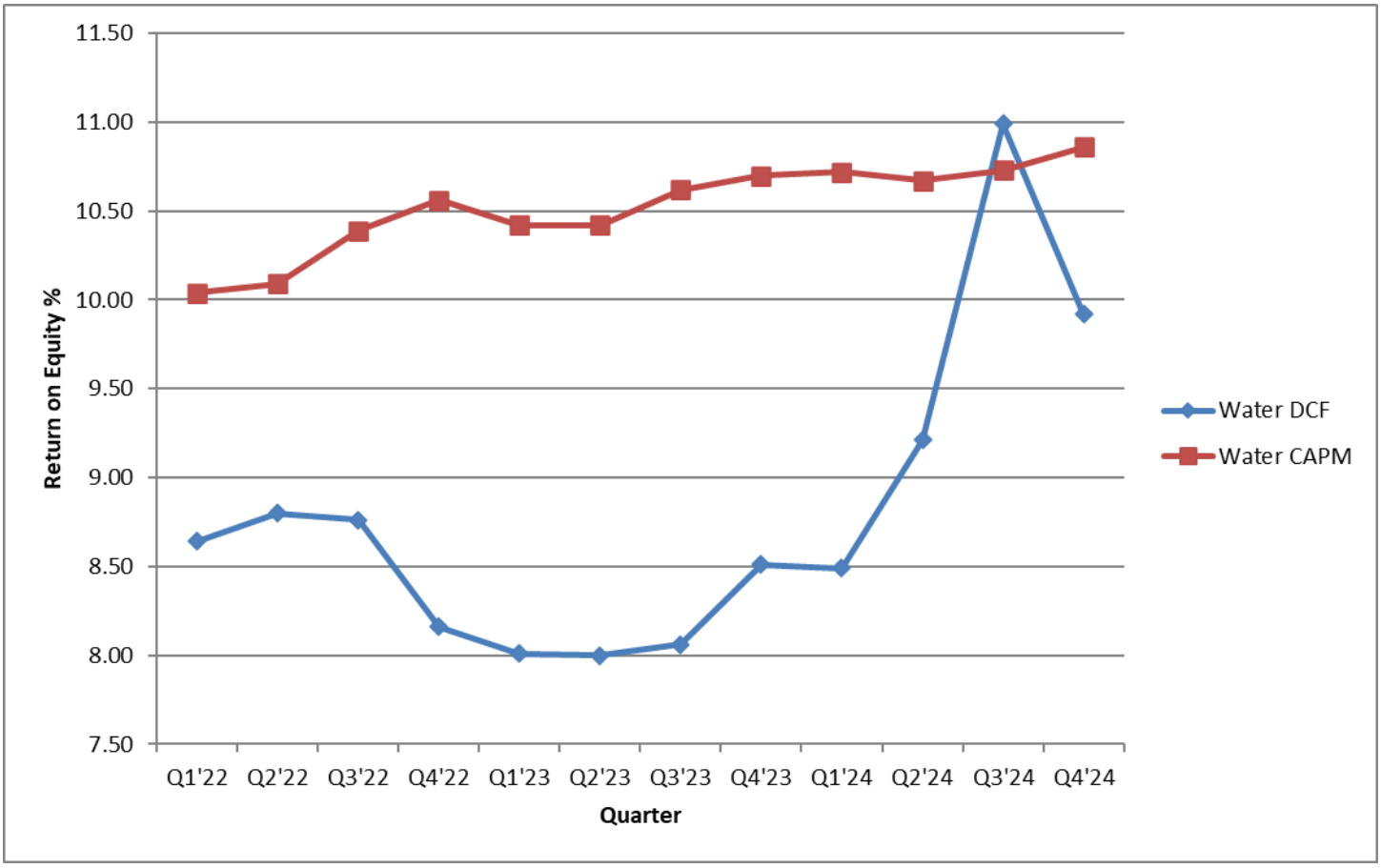
The market indicated common equity cost rate range consists of data used from the barometer groups and is based on a series of calculations to average the DCF methods.

Market Based Returns on Common Equity [1]	
April 7, 2025	
Water Company Barometer Group	
	Cost Rates %
(1) Current DCF	9.96
(2) 52-Week Average DCF	9.88
(3) Average DCF	9.92
(4) Market Indicated Common Equity Cost Rate Range @ 1 standard deviation around the mean.[2]	7.25-12.59
(5) CAPM Check of DCF Reasonableness	10.86
(6) Recent Commission Approved ROEs[3]:	
Columbia Water Company, R-2023-3040258	9.75
Pennsylvania-American water Company, R-2023-3043189	9.45
(7) Distribution System Improvement Charge (DSIC) Return[4]:	**9.75%**
[1] As calculated by the Bureau of Technical Utility Services	
[2] Standard Deviation of 12 DCF observations	
[3] ROEs from base rate cases within last two years, fully litigated or stipulated for DSIC purposes	
[4] Commission authorized Return on Equity (ROE) for DSIC purposes	
Any questions concerning DSIC should be directed to Rich Layton	
of the Bureau of Technical Utility Services at (717) 214-9117.	

Historic Water Industry DCF and CAPM Average ROEs

Water		
	DCF	CAPM
Q1'22	8.64	10.04
Q2'22	8.80	10.09
Q3'22	8.76	10.39
Q4'22	8.16	10.56
Q1'23	8.01	10.42
Q2'23	8.00	10.42
Q3'23	8.06	10.62
Q4'23	8.51	10.70
Q1'24	8.49	10.72
Q2'24	9.21	10.67
Q3'24	10.99	10.73
Q4'24	9.92	10.86

Chart of Historic Water Industry DCF and CAPM Average ROEs



Barometer water companies are used to calculate a current DCF in the first chart. The second chart demonstrates the companies' 52-week average DCF. A final average of the two calculations is also shown at the bottom.

Water Company Barometer Group
Calculation of a Current Dividend Yield

	Closing Market Price (Po) 4/7/2025	Latest Indicated Dividend (Do)	Ind. Div. Plus 1/2 Div. Growth Rate (D1)	Current Dividend Yield(D1/Po)	Growth	DCF
	($)	($)	($)	(%)	(%)	(%)
American States Water Company	75.41	1.86	1.93	2.57	3.52	6.08
American Water Works Co., Inc.	142.36	3.06	3.19	2.24	6.76	9.00
California Water Service Group	47.50	1.20	1.23	2.60	9.50	12.10
Essential Utilities, Inc.	38.32	1.30	1.35	3.53	6.70	10.23
Middlesex Water Company	61.62	1.36	1.39	2.26	11.65	13.92
SJW Group	51.28	1.68	1.72	3.35	5.17	8.52
Group Average	69.42	1.74	1.80	2.76	7.22	9.97
Group Average G				7.20		
DCF				**9.96**		

Water Company Barometer Group
52-week Average Dividend Yield Calculation

	High	Low	Average (Pa)	Latest Indicated Dividend (Do)	Average Dividend Yield (Do/Pa)	Growth	DCF
	($)	($)	($)	($)	(%)	(%)	(%)
American States Water Company	87.50	66.03	76.77	1.86	2.42	3.52	5.94
American Water Works Co., Inc.	155.50	113.34	134.42	3.06	2.28	6.76	9.03
California Water Service Group	56.25	41.64	48.95	1.20	2.45	9.50	11.95
Essential Utilities, Inc.	41.78	33.18	37.48	1.30	3.47	6.70	10.17
Middlesex Water Company	70.73	45.42	58.08	1.36	2.34	11.65	14.00
SJW Group	62.18	44.91	53.55	1.68	3.14	5.17	8.31
Group Average	78.99	57.42	68.21	1.74	2.68	7.22	9.90
Group Average G					7.20		
DCF					**9.88**		
		Average of Current and 52-Week			**9.92**		

Multiple sources of the Barometer companies' projected 5-year Earnings Per Share are used to calculate the Group Average Dividend Growth Estimate.

Development of a Representative Dividend Growth Rate
for the Barometer Group of Water Companies

	5 Yr Forecast					
					Average	
	Value Line	Value Line	Zacks	S&P	Earnings	Growth
	DPS	EPS	EPS	EPS	Growth	Estimate
	(%)	(%)	(%)	(%)	(%)	(%)
American States Water Company	8.00	7.00	1.80	1.75	3.52	3.52
American Water Works Co., Inc.	8.50	4.50	8.00	7.77	6.76	6.76
California Water Service Group	5.50	9.50	42.40	42.44	31.45	9.50
Essential Utilities, Inc.	8.00	7.00	6.60	6.51	6.70	6.70
Middlesex Water Company	5.00	7.00	14.00	13.96	11.65	11.65
SJW Group	4.50	6.50	4.50	4.52	5.17	5.17
Group Average	6.58	6.92	12.88	12.83	10.88	7.22
USE						**7.20**

Sources: Value Line, April 8, 2025 (www.valueline.com)
Zacks, April 8, 2025 (www.zacks.com)
Yahoo!, April 8, 2025 (http://finance.yahoo.com/)
S&P Capital IQ, April 8, 2025 (www.spglobal.com)
* NA signifies that a forecast was not available

EXHIBIT JBF-2

			Requested			Approved				
State	Company	Case identification	Date	Rate Change ($000)	Return on Equity (%)	Date	Rate Change ($000)	Return on Equity (%)	Case Type	Decision Type
MD	Potomac Electric Power Company	C-9702	5/16/2023	187,912	10.50	6/10/2024	44,629	9.50	Distribution	Fully Litigated
MA	Fitchburg Gas and Electric Light Company, Inc.	DPU 23-80	8/17/2023	5,142	10.50	6/28/2024	4,849	9.40	Distribution	Fully Litigated
NY	Central Hudson Gas & Electric Corporation	C-23-E-0418	7/31/2023	128,708	9.80	7/18/2024	74,418	9.50	Distribution	Fully Litigated
MA	Massachusetts Electric Company	DPU 23-150	11/16/2023	118,300	10.50	9/30/2024	90,157	9.35	Distribution	Fully Litigated
DC	Potomac Electric Power Company	FC-1176	4/13/2023	186,488	10.50	11/25/2024	123,351	9.50	Distribution	Fully Litigated
ME	Versant Power	D-2023-00336	3/1/2024	36,144	9.35	3/13/2025	32,300	9.35	Distribution	Fully Litigated
TX	AEP Texas Inc.	D-56165	2/29/2024	100,387	10.60	10/3/2024	45,499	9.76	Distribution	Settled
NJ	Public Service Electric and Gas Company	D-ER23120924	12/29/2023	560,915	10.40	10/9/2024	440,500	9.60	Distribution	Settled
TX	CenterPoint Energy Houston Electric, LLC	D-56211	3/6/2024	14,584	10.40	3/13/2025	-33,543	9.65	Distribution	Settled
NY	Orange and Rockland Utilities, Inc.	C-24-E-0060	1/26/2024	10,678	10.25	3/20/2025	-13,060	9.75	Distribution	Settled
NH	Liberty Utilities (Granite State Electric) Corp.	D-DE-23-039	5/5/2023	20,155	10.35	3/25/2025	323	9.10	Distribution	Settled
MI	Indiana Michigan Power Company	C-U-21461	9/15/2023	41,113	10.50	7/2/2024	21,620	9.86	Vertically Integrated	Fully Litigated
VT	Green Mountain Power Corporation	C-24-1709-TF	5/31/2024	38,060	9.97	8/26/2024	38,060	9.97	Vertically Integrated	Fully Litigated
NV	Sierra Pacific Power Company	D-24-02026	2/23/2024	96,223	10.47	9/18/2024	40,315	9.74	Vertically Integrated	Fully Litigated
CA	San Diego Gas & Electric Company	A-22-04-012 (Phase 2)	1/16/2024	NA	10.65	10/17/2024	-24,900	10.23	Vertically Integrated	Fully Litigated
CA	Pacific Gas and Electric Company	A-22-04-008 (Phase 2)	1/16/2024	NA	10.70	10/17/2024	-114,900	10.28	Vertically Integrated	Fully Litigated
CA	Southern California Edison Company	A-22-04-009 (Phase 2)	1/16/2024	NA	10.75	10/17/2024	-104,400	10.33	Vertically Integrated	Fully Litigated
VA	Appalachian Power Company	C-PUR-2024-00024	3/29/2024	78,304	10.80	11/20/2024	9,768	9.75	Vertically Integrated	Fully Litigated
FL	Tampa Electric Company	D-20240026-EI	4/2/2024	295,522	11.50	12/3/2024	184,881	10.50	Vertically Integrated	Fully Litigated
OR	PacifiCorp	D-UE-433	2/14/2024	208,800	9.65	12/19/2024	139,653	9.50	Vertically Integrated	Fully Litigated
WI	Wisconsin Public Service Corporation	D-6690-UR-128 (Elec)	4/12/2024	172,349	10.00	12/19/2024	85,095	9.80	Vertically Integrated	Fully Litigated
WI	Wisconsin Electric Power Company	D-5-UR-111 (Elec)	4/12/2024	423,334	10.00	12/19/2024	313,507	9.80	Vertically Integrated	Fully Litigated
OR	Portland General Electric Company	D-UE-435	2/29/2024	249,900	9.50	12/20/2024	100,000	9.34	Vertically Integrated	Fully Litigated
WA	Avista Corporation	D-UE-240006	1/18/2024	112,156	10.40	12/20/2024	80,735	9.80	Vertically Integrated	Fully Litigated
WA	Puget Sound Energy, Inc.	D-UE-240004	2/15/2024	588,003	10.50	1/15/2025	529,915	9.90	Vertically Integrated	Fully Litigated
MI	DTE Electric Company	C-U-21534	3/28/2024	441,049	10.50	1/23/2025	217,380	9.90	Vertically Integrated	Fully Litigated
IN	Duke Energy Indiana, LLC	Ca-46038	4/4/2024	536,149	10.50	1/29/2025	295,678	9.75	Vertically Integrated	Fully Litigated
FL	Florida Public Utilities Company	D-20240099-EI	8/22/2024	12,593	11.30	3/4/2025	8,400	10.20	Vertically Integrated	Fully Litigated
CO	Black Hills Colorado Electric, Inc.	D-24AL-0275E	6/14/2024	25,144	9.83	3/12/2025	17,032	9.40	Vertically Integrated	Fully Litigated
MI	Consumers Energy Company	C-U-21585	5/31/2024	255,433	10.25	3/21/2025	153,809	9.90	Vertically Integrated	Fully Litigated
UT	PacifiCorp	D-24-035-04	6/28/2024	331,500	9.65	4/25/2025	87,233	9.38	Vertically Integrated	Fully Litigated
KY	Kentucky Power Company	C-2023-00159	6/29/2023	93,936	9.90	1/19/2024	60,032	9.75	Vertically Integrated	Settled
VA	Virginia Electric and Power Company	C-PUR-2023-00101	7/3/2023	104,605	9.70	2/28/2024	0	9.70	Vertically Integrated	Settled
WV	Monongahela Power Company	C-23-0460-E-42T	5/31/2023	172,788	10.85	3/26/2024	105,000	9.80	Vertically Integrated	Settled
IN	AES Indiana	Ca-45911	6/28/2023	134,242	10.60	4/17/2024	71,037	9.90	Vertically Integrated	Settled
IN	Indiana Michigan Power Company	Ca-45933	8/9/2023	116,376	10.50	5/8/2024	61,542	9.85	Vertically Integrated	Settled
SC	Duke Energy Carolinas, LLC	D-2023-388-E	1/4/2024	323,052	10.50	6/20/2024	233,847	9.94	Vertically Integrated	Settled
SC	Dominion Energy South Carolina, Inc.	D-2024-34-E	3/1/2024	302,894	10.60	8/8/2024	219,470	9.94	Vertically Integrated	Settled
FL	Duke Energy Florida, LLC	D-20240025-EI	4/2/2024	819,945	11.15	8/21/2024	470,000	10.30	Vertically Integrated	Settled
IA	Interstate Power and Light Company	D-RPU-2023-0002 (electric)	10/12/2023	457,934	10.11	9/17/2024	185,000	9.87	Vertically Integrated	Settled
OR	Idaho Power Company	D-UE-426	12/15/2023	10,695	10.40	9/23/2024	6,732	9.50	Vertically Integrated	Settled
MI	Upper Peninsula Power Company	C-U-21555	3/21/2024	16,914	10.70	9/26/2024	9,000	9.86	Vertically Integrated	Settled
MI	Upper Michigan Energy Resources Corporation	C-U-21541	5/1/2024	11,162	10.25	10/10/2024	6,600	9.86	Vertically Integrated	Settled
MN	Minnesota Power Enterprises, Inc.	D-E-015/GR-23-155	11/1/2023	127,853	10.30	10/24/2024	89,168	9.78	Vertically Integrated	Settled
OK	Oklahoma Gas and Electric Company	Ca-PUD2023-000087	12/29/2023	332,537	10.50	11/26/2024	126,660	9.50	Vertically Integrated	Settled
ND	Otter Tail Power Company	C-PU-23-342	11/2/2023	44,773	10.60	12/30/2024	36,444	10.10	Vertically Integrated	Settled
NC	Virginia Electric and Power Company	E-22, Sub 694	3/28/2024	60,863	10.60	1/14/2025	36,835	9.95	Vertically Integrated	Settled
OK	Public Service Company of Oklahoma	Ca-PUD2023-000086	1/31/2024	217,379	10.80	1/15/2025	119,500	9.50	Vertically Integrated	Settled
CA	Bear Valley Electric Service, Inc.	A-22-08-010	8/30/2022	17,520	11.25	1/16/2025	13,095	10.00	Vertically Integrated	Settled
IN	Southern Indiana Gas and Electric Company	Ca-45990	12/5/2023	118,758	10.40	2/3/2025	93,973	9.80	Vertically Integrated	Settled
NM	Public Service Company of New Mexico	C-24-00089-UT	6/14/2024	174,320	10.45	5/15/2025	105,000	9.45	Vertically Integrated	Settled
VA	Appalachian Power Company	C-PUR-2023-00102 (BC-RA	8/25/2023	7,022	9.50	2/20/2024	7,022	9.50	Limited-Issue Rider	Fully Litigated
VA	Virginia Electric and Power Company	C-PUR-2023-00094 (Rider C	6/1/2023	8,247	9.70	2/21/2024	4,965	9.70	Limited-Issue Rider	Fully Litigated
VA	Virginia Electric and Power Company	C-PUR-2023-00184 (Rider F	10/10/2023	10,104	9.70	3/22/2024	10,104	9.70	Limited-Issue Rider	Fully Litigated

			Requested			Approved				
State	Company	Case identification	Date	Rate Change ($000)	Return on Equity (%)	Date	Rate Change ($000)	Return on Equity (%)	Case Type	Decision Type
VA	Virginia Electric and Power Company	C-PUR-2023-00142 (Rider C	10/3/2023	47,522	9.70	3/29/2024	44,126	9.70	Limited-Issue Rider	Fully Litigated
VA	Virginia Electric and Power Company	C-PUR-2023-00137 (Rider U	8/1/2023	-3,731	9.70	4/29/2024	-3,731	9.70	Limited-Issue Rider	Fully Litigated
VA	Virginia Electric and Power Company	C-PUR-2023-00138 (Rider U	8/1/2023	-2,273	9.70	4/29/2024	-2,273	9.70	Limited-Issue Rider	Fully Litigated
VA	Virginia Electric and Power Company	C-PUR-2023-00136 (Rider C	8/1/2023	130,389	9.70	5/1/2024	130,389	9.70	Limited-Issue Rider	Fully Litigated
VA	Virginia Electric and Power Company	C-PUR-2023-00171 (Rider S	10/3/2023	45,145	9.70	7/3/2024	18,788	9.70	Limited-Issue Rider	Fully Litigated
VA	Virginia Electric and Power Company	C-PUR-2023-00172 (Rider U	10/3/2023	75,286	9.70	7/3/2024	75,286	9.70	Limited-Issue Rider	Fully Litigated
VA	Appalachian Power Company	C-PUR-2023-00169 (RAC-E	11/30/2023	14,956	9.20	7/26/2024	11,493	9.20	Limited-Issue Rider	Fully Litigated
VA	Virginia Electric and Power Company	C-PUR-2023-00195 (Rider C	11/1/2023	214,938	9.70	7/26/2024	214,937	9.70	Limited-Issue Rider	Fully Litigated
VA	Virginia Electric and Power Company	C-PUR-2023-00217 (Rider I	12/11/2023	-14,820	9.70	7/26/2024	-15,189	9.70	Limited-Issue Rider	Fully Litigated
VA	Virginia Electric and Power Company	C-PUR-2024-00013 (Rider E	1/24/2024	-37,077	9.70	9/19/2024	-37,077	9.70	Limited-Issue Rider	Fully Litigated
VA	Virginia Electric and Power Company	C-PUR-2024-00029 (Rider C	3/5/2024	-91,200	9.70	11/4/2024	-91,200	9.70	Limited-Issue Rider	Fully Litigated
VA	Virginia Electric and Power Company	C-PUR-2024-00097 (Rider C	6/4/2024	84,436	9.70	2/27/2025	55,655	9.70	Limited-Issue Rider	Fully Litigated
VA	Virginia Electric and Power Company	C-PUR-2024-00180 (Rider F	10/1/2024	6,967	9.70	3/26/2025	6,967	9.70	Limited-Issue Rider	Fully Litigated
VA	Virginia Electric and Power Company	C-PUR-2024-00147 (Rider C	10/16/2024	48,354	9.70	4/15/2025	48,260	9.70	Limited-Issue Rider	Fully Litigated
VA	Virginia Electric and Power Company	C-PUR-2024-00137 (Rider E	8/1/2024	-23,357	9.70	5/1/2025	-27,382	9.70	Limited-Issue Rider	Fully Litigated

Source: S&P Capital IQ (dated 6-25-2025)

EXHIBIT JBF-3

DIRECT TESTIMONY WORKPAPERS**

JBF WP-1 Citizens' Electric Exhibit HSG-1 (Schedule A-D)**

JBF WP-2 I&E-RE-5-D Attachment A (Direct)**

JBF WP-3 Survey of Electric ROE**

The above referenced workpapers, JBF WP-1, JBF WP-2, and JBF WP-3 will be served electronically in excel format only, simultaneous to service of OSBA's Direct Testimony ONLY

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	**Docket No. R-2025-3054394**
	:	
Citizens' Electric Company of Lewisburg, PA	:	

VERIFICATION

I, Justin B. Farr, hereby state that the facts set forth in my Direct Testimony, labelled OSBA Statement No. 1, and Exhibit JBF-1, Exhibit JBF-2, and Exhibit JBF-3, are true and correct to the best of my knowledge, information, and belief, and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements made herein are subject to the penalties of 18 Pa. C.S. § 4904 (relating to unsworn falsification to authorities).

Date: July 14, 2025

Justin B. Farr

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	**Docket No. R-2025-3054394**
	:	
Citizens' Electric Company of Lewisburg, PA	:	
	:	

CERTIFICATE OF SERVICE

I hereby certify that true and correct copies of the foregoing have been served via email (*unless otherwise noted below*) upon the following persons, in accordance with the requirements of 52 Pa. Code § 1.54 (relating to service by a participant).

The Honorable Mary D. Long
Administrative Law Judge
Pennsylvania Public Utility Commission
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Date: July 15, 2025

/s/ Rebecca Lyttle
Rebecca Lyttle
Assistant Small Business Advocate
Attorney ID No. 201399

COMMONWEALTH OF PENNSYLVANIA

August 13, 2025

The Honorable Mary D. Long
Administrative Law Judge
Pennsylvania Public Utility Commission
Piatt Place
301 Fifth Avenue, Suite 220
Pittsburgh, PA 15222

Re: Pennsylvania Public Utility Commission v. Citizens' Electric Company of Lewisburg, PA / Docket No. R-2025-3054394

Dear Judge Long:

Enclosed please find the Rebuttal Testimony of Justin B. Farr, labelled OSBA Statement No.1-R, on behalf of the Office of Small Business Advocate ("OSBA"), in the above-referenced proceeding.

As evidenced by the enclosed Certificate of Service, all known parties will be served, as indicated.

If you have any questions, please do not hesitate to contact me.

Sincerely,

/s/ Rebecca Lyttle

Rebecca Lyttle
Assistant Small Business Advocate
Attorney ID No. 201399

Enclosures
cc: PA PUC Secretary Matthew L. Homsher (Cover Letter & Certificate of Service only)
Kevin Higgins / Rebecca Forbes / Justin Farr
Joseph Kubas
Parties of Record

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	**:**	
	:	
v.	**:**	**Docket No. R-2025-3054394**
	:	
Citizens' Electric Company of Lewisburg, PA	**:**	
	:	

Rebuttal Testimony

of

Justin B. Farr

on behalf of

Pennsylvania Office of Small Business Advocate

Topics:

Classification of Distribution Costs

Date Served: August 13, 2025

Date Submitted for the Record: _____

REBUTTAL TESTIMONY OF JUSTIN B. FARR

INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Justin B. Farr. My business address is 111 East Broadway, Suite 1200, Salt Lake City, Utah, 84111.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am a Director in the firm of Energy Strategies, LLC. Energy Strategies is a private consulting firm specializing in economic and policy analysis applicable to energy production, transportation, and consumption.

Q. ARE YOU THE SAME JUSTIN B. FARR WHO PREFILED DIRECT TESTIMONY IN THIS DOCKET ON BEHALF OF THE PENNSYLVANIA OFFICE OF SMALL BUSINESS ADVOCATE ("OSBA")?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR SURREBUTTAL TESTIMONY?

A. My rebuttal testimony responds to the direct testimony of Citizens' witness Howard Gorman and Pennsylvania Office of Consumer Advocate ("OCA") witness Michael Deupree.

RESPONSE TO CITIZENS

Q. DO YOU AGREE WITH CITIZENS' FILED COST OF SERVICE STUDY WITH RESPECT TO THE CLASSIFICATION OF SECONDARY DISTRIBUTION PLANT ACCOUNTS 364 THROUGH 366?

A. Yes. Citizens Electric ("Citizens" or "the Company") proposes to classify distribution plant accounts 364 through 366 as partially demand-related, and partially customer-related. I agree with this approach. Citizens witness Mr. Gorman conducted a zero-load analysis to determine the customer-related component of secondary-voltage distribution system costs included in accounts 364-366.[1] Mr. Gorman's use of the zero-load analysis to classify distribution plant assets in accounts 366-366 as partially customer-related is supported by the National Association of Regulatory Utility Commissions ("NARUC").

Q. HOW IS SECONDARY DISTRIBUTION PLANT IN ACCOUNT 368 (LINE TRANSFORMERS) PURPORTED TO BE CLASSIFIED?

A. According to Mr. Gorman's testimony, Account 368 was classified between customer-related and demand-related using a minimum size analysis[2] which results in the 35.85% customer allocation factor included in Schedule D3.[3] The resulting demand allocation factor is 64.15%.[4]

Q. HOW WAS SECONDARY PLANT IN ACCOUNT 368 ACTUALLY CLASSIFIED?

A. Account 368 was classified as 100% demand related.[5] There is clearly a discrepancy between the testimony and class cost of service study regarding how this account was classified.

[1] Direct Testimony of Howard S. Gorman (Citizens' Statement No. 1), page 20 ln 6-7.
[2] Direct Testimony of Howard S. Gorman (Citizens' Statement No. 1), page 20 ln 16-17.
[3] Citizens' Electric Exhibit HSG-1 (Schedule A-D), worksheet D3, row 30.
[4] Citizens' Electric Exhibit HSG-1 (Schedule E), worksheet ClassFctr, row 23, column G.
[5] Citizens' Electric Exhibit HSG-1 (Schedule E), worksheet Classify, row 17, column U.

Q. DO YOU HAVE A RECOMMENDATION ON HOW TO CLASSIFY SECONDARY PLANT IN ACCOUNT 368?

A. Yes, I recommend the secondary distribution plant in account 368 be classified as partially customer-related and partially demand-related as described in Mr. Gorman's testimony.

RESPONSE TO OCA

Q. WHAT DOES OCA WITNESS MR. DEUPREE RECOMMEND REGARDING THE CLASSIFICATION OF DISTRIBUTION PLANT ACCOUNTS 364 THROUGH 368?

A. Mr. Deupree recommends that the Commission reject the Company's proposed use of zero-load analysis and minimum-size analysis, together referred to as the minimum system study ("MSS") approach, for classifying the costs of secondary-voltage distribution plant included in FERC accounts 364 through 368. He claims that both the minimum system and zero-intercept methods are fundamentally flawed, offer little to no value in setting just and reasonable rates, and have been discredited by research. He further notes that some state regulatory commissions have expressly rejected the use of these methods. Instead, Mr. Deupree recommends that the Commission classify the assets in distribution plant accounts 364 through 368 as 100 percent demand-related.[6]

Q. WHAT EVIDENCE DOES MR. DEUPREE PROVIDE TO SUPPORT HIS RECOMMENDATION?

[6] OCA Statement No. 3, Direct Testimony of Michael Deupree, pages 21-22.

A. Mr. Deupree cites a passage from the Electric Utility Cost Allocation Manual published by NARUC ("NARUC Manual") in support of his position. However, the NARUC Manual clearly states that Accounts 364 through 368 contain both customer-related and demand-related components. In addition, Mr. Deupree references two jurisdictions that have rejected the use of MSS analyses. He does not acknowledge the jurisdictions that use MSS analyses.

Q. IS YOUR POSITION CONSISTENT WITH THE RECOMMENDED TREATMENT OF THESE COSTS AS PRESENTED IN THE NARUC MANUAL?

A. Yes, it is. The NARUC Manual states that:

> Distribution Plant Accounts 364 through 370 involve demand and customer costs. **The customer component of distribution facilities is that portion of costs which varies with the number of customers. Thus, the number of poles, conductors, transformers, services, and meters are directly related to the number of customers on the utility's system**. As shown in Table 6-1, each primary plant account can be separately classified into a demand and customer component. Two methods are used to determine the demand and customer components of distribution facilities. They are, the minimum-size-of-facilities method, and the minimum-intercept cost (zero-intercept or positive-intercept cost, as applicable) of facilities[7] (emphasis added).

Table 6-1, referenced above, from the NARUC Manual is included below. Table 6-1 shows FERC Accounts 364-368 as having demand-related and customer-related components.

[7] Electric Utility Cost Allocation Manual, January 1992, p. 90.

TABLE 6-1

CLASSIFICATION OF DISTRIBUTION PLANT[1]

FERC Uniform System of Accounts No.	Description	Demand Related	Customer Related
	Distribution Plant [2]		
360	Land & Land Rights	X	X
361	Structures & Improvements	X	X
362	Station Equipment	X	-
363	Storage Battery Equipment	X	-
364	Poles, Towers, & Fixtures	X	X
365	Overhead Conductors & Devices	X	X
366	Underground Conduit	X	X
367	Underground Conductors & Devices	X	X
368	Line Transformers	X	X
369	Services	-	X
370	Meters	-	X
371	Installations on Customer Premises	-	X
372	Leased Property on Customer Premises	-	X
373	Street Lighting & Signal Systems [1]	-	-

[1]Assignment or "exclusive use" costs are assigned directly to the customer class or group which exclusively uses such facilities. The remaining costs are then classified to the respective cost components.

[2]The amounts between classification may vary considerably. A study of the minimum intercept method or other appropriate methods should be made to determine the relationships between the demand and customer components.

Q. WHAT IS YOUR RESPONSE TO MR. DEUPREE'S RECOMMENDATION THAT COSTS ASSOCIATED WITH DISTRIBUTION PLANT ACCOUNTS 364 THROUGH 368 BE CLASSIFIED AND ALLOCATED ON ONLY A DEMAND BASIS?

A. I disagree with Mr. Deupree's recommendation. The costs associated with distribution plant accounts 364 through 368 include facilities such as poles and

conductors, which have a significant customer-related component. These facilities are installed to deliver service to customer premises, and a substantial portion of the investment required is directly related to the number of customers and their geographic dispersion across the utility's service territory.

A well-designed and equitable distribution cost-of-service study should reflect these cost-causation factors. By contrast, Mr. Deupree's approach overlooks the influence of customer count and geographic layout on system investment needs. His proposal to classify all costs in these accounts as solely demand-related would under-assign cost responsibility to customers based on their number and location, while over-assigning costs based solely on demand. This would result in an unreasonable cost shift to larger customers served on the distribution system. I recommend that the Commission maintain the Company's proposed approach which correctly classifies distribution plant accounts 364 through 368 as partially demand-related, and partially customer-related.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	**Docket No. R-2025-3054394**
	:	
Citizens' Electric Company of Lewisburg, PA	:	
	:	

VERIFICATION

I, Justin B. Farr, hereby state that the facts set forth in my Rebuttal Testimony, labelled OSBA Statement No. 1-R, are true and correct to the best of my knowledge, information, and belief, and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements made herein are subject to the penalties of 18 Pa. C.S. § 4904 (relating to unsworn falsification to authorities).

Date: August 12, 2025

Justin B. Farr

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	**Docket No. R-2025-3054394**
	:	
Citizens' Electric Company of Lewisburg, PA	:	
	:	

CERTIFICATE OF SERVICE

I hereby certify that true and correct copies of the foregoing have been served via email (*unless otherwise noted below*) upon the following persons, in accordance with the requirements of 52 Pa. Code § 1.54 (relating to service by a participant).

The Honorable Mary D. Long
Administrative Law Judge
Pennsylvania Public Utility Commission
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301 Fifth Avenue, Suite 220
Pittsburgh, PA 15222
malong@pa.gov

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Date: August 13, 2025

/s/ Rebecca Lyttle
Rebecca Lyttle
Assistant Small Business Advocate
Attorney ID No. 201399

COMMONWEALTH OF PENNSYLVANIA

August 28, 2025

The Honorable Mary D. Long
Administrative Law Judge
Pennsylvania Public Utility Commission
Piatt Place
301 Fifth Avenue, Suite 220
Pittsburgh, PA 15222

Re: Pennsylvania Public Utility Commission v. Citizens' Electric Company of Lewisburg, PA / Docket No. R-2025-3054394

Dear Judge Long:

Enclosed please find the Surrebuttal Testimony and Exhibit of Justin B. Farr, labelled OSBA Statement No.1-SR, with associated Exhibit JBF-1SR, on behalf of the Office of Small Business Advocate ("OSBA"), in the above-referenced proceeding.

As evidenced by the enclosed Certificate of Service, all known parties will be served, as indicated.

If you have any questions, please do not hesitate to contact me.

Sincerely,

/s/ Rebecca Lyttle

Rebecca Lyttle
Assistant Small Business Advocate
Attorney ID No. 201399

Enclosures
cc: PA PUC Secretary Matthew L. Homsher (Cover Letter & Certificate of Service only)
Kevin Higgins / Rebecca Forbes / Justin Farr
Joseph Kubas
Parties of Record

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	**:**	
	:	
v.	**:**	**Docket No. R-2025-3054394**
	:	
Citizens' Electric Company of Lewisburg, PA	**:**	
	:	

Surrebuttal Testimony and Exhibit

of

Justin B. Farr

on behalf of

Pennsylvania Office of Small Business Advocate

Topics:

Revenue Requirement Adjustments

Date Served: August 28, 2025

Date Submitted for the Record: _____

SURREBUTTAL TESTIMONY OF JUSTIN B. FARR

INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Justin B. Farr. My business address is 111 East Broadway, Suite 1200, Salt Lake City, Utah, 84111.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am a Director in the firm of Energy Strategies, LLC. Energy Strategies is a private consulting firm specializing in economic and policy analysis applicable to energy production, transportation, and consumption.

Q. ARE YOU THE SAME JUSTIN B. FARR WHO PREFILED DIRECT TESTIMONY AND REBUTTAL TESTIMONY IN THIS DOCKET ON BEHALF OF THE PENNSYLVANIA OFFICE OF SMALL BUSINESS ADVOCATE ("OSBA")?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR SURREBUTTAL TESTIMONY?

A. My surrebuttal testimony responds to the rebuttal testimony of Citizens' Electric Company of Lewisburg ("Citizens" or "the Company") witness Dylan W. D'Ascendis, and Pennsylvania Office of Consumer Advocate ("OCA") witness Christopher C. Walters regarding my use of a 10% proxy return on equity ("ROE") in my revenue requirement calculations.

I respond to Citizens' witness Nathan Johnson regarding the Performance Factor Adjustment and the Size Adjustment.

I also respond to rebuttal testimony of Citizens' witness Kathy Stauder regarding statements made about sponsorship, meter expense, and my O&M inflationary adjustments.

Q. WHAT CONCLUSIONS DO YOU OFFER IN YOUR SURREBUTTAL TESTIMONY?

A. I offer the following conclusions:

1) I explain my use of a proxy ROE in my direct testimony revenue requirement calculations and provide the results of my revenue requirement calculations using the costs of capital recommended by the Bureau of Investigation & Enforcement ("I&E") and OCA.
2) I continue to recommend eliminating the performance factor entirely and lowering or removing the size factor adjustment.
3) I continue to recommend the revenue requirement adjustment of $16,051 for O&M Inflationary Adjustments as I explained in my direct testimony.

REVENUE REQUIREMENT ADJUSTMENTS

Proxy Return on Equity Adjustment

Q. PLEASE DESCRIBE YOUR PROXY ROE ADJUSTMENT.

A. I assumed the 10% ROE authorized by the Commission for the Distribution System Improvement Charge ("DSIC") included in the most recent Report on the Quarterly Earnings of Jurisdictional Utilities for the year ended December 31, 2024 produced by the Bureau of Technical Utility Services ("TUS").[1]

[1] Direct Testimony of Justin B. Farr (OSBA Statement No. 1) p. 17.

Q. DO ANY PARTIES TAKE ISSUE WITH YOUR USE OF THIS PLACEHOLDER ROE?

A. Yes. Citizens' witness Dylan W. D'Ascendis testifies that while the range of ROEs calculated by the TUS in its quarterly report is generally consistent with both his initial and updated model results – and while the upper end of the TUS ranges for gas and electric utilities aligns with his Company-specific recommendation – the TUS ranges do not account for the performance of Citizens' management. As a result, he argues the TUS analysis provides an incomplete basis for determining the Companies' appropriate ROE.[2]

OCA witness Christopher C. Walters states that he disagrees with my use of a 10% DSIC ROE from the Commission's Quarterly Earnings Report as a proxy ROE for the Company. He claims that the Commission has expressly and repeatedly rejected the use of its DSIC ROE for purposes of establishing the cost of equity in base rate proceedings and cites one case, a Pike County Light and Power rate case.[3] Mr. Walters concludes that because my proxy ROE is not grounded in a proper cost of equity analysis and is inconsistent with Commission precedent, the portion attributed to ROE of my proposed downward adjustment to the Company's revenue requirement should be rejected.[4]

Q. HOW DO YOU RESPOND TO THESE CONCERNS?

A. To clarify, I am not suggesting that the DSIC ROE be adopted in this proceeding in the absence of a detailed ROE analysis. My use of the proxy 10% DSIC ROE is

[2] Rebuttal Testimony of Dylan W. D'Ascendis (Joint Statement No. 2R) p. 3.
[3] Rebuttal Testimony of Christopher C. Walters (OCA Statement 2R) p. 14.
[4] *Id.* p.16.

not intended to replace the Commission's consideration of traditional cost of capital analyses offered by other parties in this proceeding.

Q. HAVE YOU ANALYZED THE IMPACT OF OTHER PARTIES' COST OF CAPITAL RECOMMENDATIONS ON YOUR REVENUE REQUIREMENT CALCULATIONS?

A. Yes. In Table JBF-1SR, I provide a summary of the total revenue increases that would result from utilizing I&E's and OCA's recommended return on equity rate in my revenue requirement calculations.

Table JBF-1SR
OSBA Revenue Increase with OCA and I&E ROE Recommendations

	Low	Mid	High
Source of ROE Assumption	OCA	OSBA	I&E
ROE Rate Assumption	9.50%	10.00%	10.78%
Total Revenue Increase*	$1,462,826	$1,524,881	$1,619,205
Difference from OSBA Direct	-$62,055	$0	$94,324

*Assumes adjustments made in OSBA Direct Testimony

For comparison purposes, Table JBF-2SR summarizes the total revenue increases that I recommended in my direct testimony, as well as those recommended by I&E, OCA, and Citizens.

Table JBF-2SR
Comparison of Proposed Revenue Increases

	Revenue Increase	Difference from Citizen's
Citizen's Application	$1,794,525	$0
OSBA Direct Testimony	$1,524,881	-$269,644
I&E Direct Testimony	$1,478,944	-$315,581
OCA Direct Testimony	$1,108,317	-$686,208

Performance Factor Adjustment and Size Adjustment

Q. PLEASE DESCRIBE YOUR PERFORMANCE FACTOR ADJUSTMENT AND SIZE ADJUSTMENT PROPOSALS.

A. I recommend eliminating the performance factor entirely and lowering or removing the size factor adjustment.[5]

Q. HOW DID CITIZENS RESPOND TO YOUR PERFORMANCE FACTOR ADJUSTMENT?

A. Citizens' witness Nathan Johnson states that the Company agrees there is no obligation or entitlement to performance adjustments, and that satisfactory performance does not warrant an adjustment. He states that the proposed adjustment, however, is based on exceptional performance provided above and beyond regulatory requirements and provides examples of the Company's exceptional performance as he did in direct testimony. He also states that the Commission acknowledged the adjustment in the Company's 2019 proceeding and concludes by urging the Commission to recognize the value of regulatory consistency and certainty by adopting a similar approach in this proceeding.[6]

Q. HOW DID CITIZENS RESPOND TO YOUR SIZE ADJUSTMENT PROPOSAL?

A. Mr. Johnson states that the Commission acknowledged the adjustment in the Company's 2019 proceedings and urges the Commission to recognize the value of regulatory consistency and certainty by adopting a similar approach in this proceeding. He also states that the Company has lost several major customers in

[5] Direct Testimony of Justin B. Farr (OSBA Statement No. 1) p. 15.
[6] Rebuttal Testimony of Nathan Johnson (Citizens' Statement No. 4R) pp. 2-5.

recent years, and large net metering installations continue to increase in number. In contrast, new load has failed to offset or exceed these losses.[7]

Q. HOW DO YOU RESPOND TO CITIZENS' POSITION THAT THE COMMISSION SHOULD RECOGNIZE THE VALUE OF REGULATORY CONSISTENCY AND CERTAINTY BY ADOPTING SIMILAR APPROACHES IN THIS PROCEEDING FOR THE PERFORMANCE FACTOR ADJUSTMENT AND THE SIZE ADJUSTMENT AS IN PREVIOUS PROCEEDINGS?

A. Consistency cannot be the justification for perpetuating adjustments that are unwarranted. Citizens should not receive upward adjustments simply for meeting obligations that every regulated utility is required to meet. Nor should it benefit from adjustments intended to shield it from hypothetical or speculative risks. Citizens already operates under a framework that provides consistency and certainty, as a regulated utility, the Company is guaranteed a rate of return. That guarantee offers far greater consistency and certainty than what is available to nearly all other businesses subject to competitive market forces. Extending additional adjustments in the name of consistency would only reward Citizens beyond what is reasonable or necessary.

Q. HOW DO YOU RESPOND TO MR. JOHNSON'S STATEMENT THAT THE COMPANY HAS LOST SEVERAL MAJOR CUSTOMERS IN RECENT YEARS, AND LARGE NET METERING INSTALLATIONS

[7] *Id.* p.6.

CONTINUE TO INCREASE IN NUMBER AND IN CONTRAST, NEW LOAD HAS FAILED TO OFFSET OR EXCEED THESE LOSSES?

A. The Company's claims of potential declining load are speculative. Even if the Company were to face significant load losses, it can file a new rate case with the Commission. Speculative concerns about potential load loss do not justify imposing upward adjustments that ultimately burden customers. Customers should not be forced to act as insurers for the Company against hypothetical scenarios that may never occur.

Q. DID I&E AND OCA MAKE PROPOSALS RELATED TO THE PERFORMANCE FACTOR ADJUSTMENT AND THE SIZE ADJUSTMENT?

A. Yes. Both I&E and OCA witnesses recommended eliminating the performance factor adjustment and the size adjustment.

Sponsorships & Meter Expense

Q. CITIZENS' WITNESS MS. STAUDER ATTRIBUTES PROPOSED ADJUSTMENTS TO SPONSORSHIPS AND METER EXPENSES TO YOU. DID YOU PROPOSE ADJUSTMENTS TO SPONSORSHIPS AND METER EXPENSES IN YOUR DIRECT TESTIMONY?

A. No, I did not. Ms. Stauder seems to have confused me with Mr. Walker, a witness for I&E.

O&M Inflationary Adjustment

Q. PLEASE DESCRIBE YOUR O&M INFLATIONARY ADJUSTMENT.

A. I generally agree with using a generic inflationary factor for budget items that cannot be developed through a bottom-up approach, but I proposed two modifications to the Company's methodology that resulted in a downward revenue requirement adjustment of $16,051.

First, I recommended using actual 2024 values, but since these were unavailable, I recommended using the Company's calculated 3-year average values instead of the company's "Normalized 3-year Average" to act as a proxy for 2024 values. The normalized method used by the company results in a 5.0% increase from 2023 to 2024, which is excessive compared to the historical compound annual growth rate ("CAGR") of 1.6% from 2019–2023. Using the 3-year average to represent 2024 values produces a 1.9% increase from 2023 to 2024, which is more reasonable when compared to the CAGR of 1.6% experienced over the last four years.

Second, I recommended applying a 2.0% inflation factor for escalating values to 2025 and 2026, rather than Citizens' proposed 3.0%, as 2.0% better reflects recent inflation trends for these accounts.[8]

Q. HOW DID CITIZENS RESPOND TO YOUR O&M INFLATIONARY ADJUSTMENT?

[8] Direct Testimony of Justin B. Farr (OSBA Statement No. 1) pp. 8-9.

A. Citizens witness Kathy Stauder claims that my omission of a normalization factor for past-year expenses undervalues them. She states that while I acknowledge inflation, I then fail to adjust past-year actuals accordingly.

Ms. Stauder introduces in her rebuttal testimony, for the first time in this proceeding, the actual 2024 expenses for the accounts subject to the generic inflation adjustment. These expenses total $323,888, reflecting a 7.6% increase over 2023 levels – a significant rise compared to prior years. Using the actual 2024 data, Ms. Stauder develops two new FPFTY 2026 projections based on generic inflation, yielding results of $336,890 and $340,145. She asserts that OSBA's proposed FPFTY 2026 value of $319,137 is a clear outlier, while both recalculated projections are slightly above the Company's original proposal. Despite her analysis using actual 2024 values, she recommends that the Commission accept the Company's original expense projections for these accounts, as presented in Mr. Gorman's Direct Testimony.[9]

Q. HOW DO YOU RESPOND TO MS. STAUDER'S PROPOSAL THAT THE COMPANY'S ORIGINAL PROPOSED EXPENSES FOR THESE ACCOUNTS BE ACCEPTED?

A. I disagree with Ms. Stauder's proposal. Once actual 2024 values are vetted and approved, they should be used to determine the amount for FPFTY 2026 that will be included in rates. But until that has happened, using the company's calculated 3-year average as a proxy for 2024 as I recommend, instead of the company's

[9] Rebuttal Testimony of Kathy Stauder (Citizens' Statement No. 5R) pp. 8-9.

normalized average, results in an inflation assumption that is more in line with what the company has experienced since 2019.

Q. DOES THIS CONCLUDE YOUR SURREBUTTAL TESTIMONY?

A. Yes, it does.

EXHIBIT JBF-1SR

SURREBUTTAL TESTIMONY WORKPAPERS**

JBF WP-1SR Citizens HSG-1 with OSBA Adj and I&E ROE**

JBF WP-2SR Citizens HSG-1 with OSBA Adj and OCA ROE**

The above referenced workpapers will be served electronically in excel format ONLY, simultaneous to service of OSBA's Surrebuttal Testimony ONLY

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	**Docket No. R-2025-3054394**
	:	
Citizens' Electric Company of Lewisburg, PA	:	
	:	

VERIFICATION

I, Justin B. Farr, hereby state that the facts set forth in my Surrebuttal Testimony and Exhibit, labelled OSBA Statement No. 1-SR, with associated Exhibit JBF-1SR, are true and correct to the best of my knowledge, information, and belief, and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements made herein are subject to the penalties of 18 Pa. C.S. § 4904 (relating to unsworn falsification to authorities).

Date: August 27, 2025

Justin B. Farr

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	**Docket No. R-2025-3054394**
	:	
Citizens' Electric Company of Lewisburg, PA	:	
	:	

CERTIFICATE OF SERVICE

I hereby certify that true and correct copies of the foregoing have been served via email (*unless otherwise noted below*) upon the following persons, in accordance with the requirements of 52 Pa. Code § 1.54 (relating to service by a participant).

The Honorable Mary D. Long
Administrative Law Judge
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Victoria A. Geddis, Esquire
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vgeddis@mcneeslaw.com

Date: August 28, 2025

/s/ Rebecca Lyttle
Rebecca Lyttle
Assistant Small Business Advocate
Attorney ID No. 201399

OSBA EXHIBIT NO. 1

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	**Docket No. R-2025-3054393**
v.	:	
	:	
Valley Energy, Inc.	:	

OFFICE OF SMALL BUSINESS ADVOCATE'S
ADMITTED
TESTIMONY AND EXHIBITS

The Office of Small Business Advocate ("OSBA") admitted the enclosed testimony and exhibits, as evidence into the evidentiary record, as OSBA EXHIBIT NO. 1, at the Evidentiary Hearing, held on September 4, 2025, in the above-captioned proceeding:

- Direct Testimony and Exhibits of Justin B. Farr, labelled OSBA Statement No.1, with Exhibit JBF-1, Exhibit JBF-2, and Exhibit JBF-3, with signed Verification of Justin B. Farr.
- Surrebuttal Testimony and Exhibit of Justin B. Farr, labelled OSBA Statement No.1-SR, with associated Exhibit JBF-1SR, with signed Verification of Justin B. Farr.

Date: September 4, 2025

COMMONWEALTH OF PENNSYLVANIA

July 15, 2025

The Honorable Mary D. Long
Administrative Law Judge
Pennsylvania Public Utility Commission
Piatt Place
301 Fifth Avenue, Suite 220
Pittsburgh, PA 15222

Re: Pennsylvania Public Utility Commission v. Valley Energy, Inc. / Docket No. R-2025-3054393

Dear Judge Long:

Enclosed please find the Direct Testimony and Exhibits of Justin B. Farr, labelled OSBA Statement No.1, on behalf of the Office of Small Business Advocate ("OSBA"), in the above-referenced proceeding.

As evidenced by the enclosed Certificate of Service, all known parties will be served, as indicated.

If you have any questions, please do not hesitate to contact me.

Sincerely,

/s/ Rebecca Lyttle

Rebecca Lyttle
Assistant Small Business Advocate
Attorney ID No. 201399

Enclosures
cc: PA PUC Secretary Matthew L. Homsher (Cover Letter & Certificate of Service only)
Kevin Higgins / Rebecca Forbes / Justin Farr
Joseph Kubas
Parties of Record

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	**:**	
	:	**Docket No. R-2025-3054393**
v.	**:**	
	:	
Valley Energy, Inc.	**:**	

Direct Testimony & Exhibits

of

Justin B. Farr

on behalf of

Pennsylvania Office of Small Business Advocate

Topics:

Revenue Requirement Adjustments

Date Served: July 15, 2025

Date Submitted for the Record: _____

DIRECT TESTIMONY OF JUSTIN B. FARR

Section I - Introduction

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Justin B. Farr. My business address is 111 East Broadway, Suite 1200, Salt Lake City, Utah, 84111.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am a Director in the firm of Energy Strategies, LLC. Energy Strategies is a private consulting firm specializing in economic and policy analysis applicable to energy production, transportation, and consumption.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?

A. My testimony is being sponsored by the Pennsylvania Office of Small Business Advocate ("OSBA").

Q. PLEASE DESCRIBE YOUR PROFESSIONAL EXPERIENCE AND QUALIFICATIONS.

A. My academic background includes a B.S. in economics and an M.B.A. from the University of Utah. After completing my undergraduate degree and while I was completing courses for my master's degree, I worked in the Utah Governor's Office as an economist focused on revenue forecasting and tax policy. I joined Energy Strategies in 2005, where I assist private and public sector clients in the areas of energy-related economic and policy analysis, including evaluation of electric and gas utility rate matters.

From 2013 to 2017 and again from 2020 to early 2022, I worked at PacifiCorp, a six-state electric utility that operates in Utah, Wyoming, Idaho, Oregon, Washington, and California. My roles at PacifiCorp included Manager of Economic & Financial Analysis where I led teams of engineers and plant managers in developing economic solutions for optimizing existing thermal and renewable infrastructure investment, and Assistant Manager of Regulation where I focused on the company's internal 10-year plan. Between 2017 and 2019, I served as Vice President of Financial Planning at Magnum Development where I supported the commercial development of the company's underground salt dome assets. My qualifications are attached in the Appendix to this testimony.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION?

A. Yes. I testified in a proceeding concerning the Second DER Management Plan filed by PPL Electric Utilities Corp, Docket No. P-2024-3049223.

Q. HAVE YOU TESTIFIED BEFORE UTILITY REGULATORY COMMISSIONS IN OTHER STATES?

A. Yes. I have provided testimony before the Utah Public Service Commission and the Indiana Utility Regulatory Commission.

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY IN THIS PROCEEDING?

A. My testimony addresses recommended revenue requirement adjustments. The absence of comment on my part regarding a particular issue or revenue requirement item does not signify support for (or opposition to) the Company's filing with respect to that issue.

Q. ARE YOU MAKING A RECOMMENDATION FOR A SPECIFIC TOTAL REVENUE REQUIREMENT IN THIS CASE?

A. No. My revenue requirement adjustment recommendations address a limited number of issues. Therefore, I am not offering a recommendation for a specific total revenue requirement.

Q. PLEASE SUMMARIZE YOUR PRIMARY CONCLUSIONS AND RECOMMENDATIONS.

A. I offer the following recommendation:

I recommend certain adjustments that will have the effect of reducing the revenue requirement by $286,940 relative to the $1.6 million increase proposed by Valley Energy, Inc. ("Valley" or "the Company"). My recommended adjustments are outlined in Table JBF-1 presented later in my testimony. My recommended reduction does not account for or incorporate any other adjustments advanced by other parties that are not specifically addressed in my testimony.

Section II - Revenue Requirement Adjustments

Q. BRIEFLY DESCRIBE THE REVENUE REQUIREMENT INCREASE BEING REQUESTED BY VALLEY IN THIS CASE.

A. Valley is requesting a $1,626,099 increase in annual distribution revenue, representing a 29.6% increase over present distribution rates. The requested increase is based on a Fully Projected Future Test Year ("FPFTY") ending

December 31, 2026, and is designed to produce an overall rate of return of 8.27% on Valley's rate base.[1]

Q. DO YOU HAVE ANY RECOMMENDED ADJUSTMENTS TO VALLEY'S PROPOSED REVENUE REQUIREMENT?

A. Yes. My recommended adjustments would reduce Valley's proposed revenue requirement increase by $286,940. As discussed in greater detail later in my testimony, this reduction incorporates a proxy return on equity ("ROE") of 10.15%, which is derived from the ROE authorized by the Commission for the Distribution System Improvement Charge ("DSIC") applicable to most natural gas utilities in the state. Table JBF-1 presents a summary of my recommended adjustments.

Table JBF-1
Summary of OSBA Adjustments to Valley's Revenue Requirement

	OSBA Adjustments	Revenue Requirement
Revenue Requirement Increase Requested by Valley		**1,626,099**
Income Tax Rate Adjustment		
Change PA Income Tax Rate from 9.99% to 7.49%	(98,668)	
Proxy Return on Equity		
Change ROE from 11.65% to Proxy 10.15%	(185,644)	
Uncollectables	(2,628)	
Adjusted Revenue Requirement Increase		**1,339,159**

I provide more detail for each of these recommended adjustments as follows:

[1] Direct Testimony of Howard S. Gorman (Valley Statement No. 1), page 15.

Pennsylvania Corporate Income Tax Rate Adjustment

Q. DESCRIBE THE PENNSYLVANIA CORPORATE NET INCOME TAX RATE AND ITS HISTORY.

A. For nearly three decades, Pennsylvania maintained a flat Corporate Net Income ("CNI") Tax rate of 9.99%, among the highest in the United States. This rate remained unchanged from 1995 until 2022. In July 2022, the Pennsylvania General Assembly enacted Act 53-2002 (H.B. 1342), initiating a phased reduction of the CNI Tax rate over nine years. The schedule for the rate reductions is as follows[2]:

Table JBF-3
Pennsylvania Corporate Net Income Tax Rates

Tax Year	CNIT Rate
January 1, 2023 - December 31, 2023	8.99 percent
January 1, 2024 - December 31, 2024	8.49 percent
January 1, 2025 - December 31, 2025	7.99 percent
January 1, 2026 - December 31, 2026	7.49 percent
January 1, 2027 - December 31, 2027	6.99 percent
January 1, 2028 - December 31, 2028	6.49 percent
January 1, 2029 - December 31, 2029	5.99 percent
January 1, 2030 - December 31, 2030	5.49 percent
January 1, 2031 and each taxable year thereafter	4.99 percent

Q. WHAT PENNSYLVANIA CNI TAX RATE WAS USED IN THE DEVELOPMENT OF THE COMPANY'S REQUESTED INCREASE IN REVENUE REQUIREMENT IN THIS CASE?

A. The Company used 9.99% as the Pennsylvania corporate income tax rate.[3]

Q. WHAT PENNSYLVANIA CNI TAX RATE DO YOU RECOMMEND?

[2] https://www.pa.gov/agencies/revenue/resources/tax-rates/corporation-tax-rates.html

[3] Direct Testimony of Howard S. Gorman (Valley Statement No. 1), page 15.

A. I recommend using 7.49% as the CNI Tax rate for FPFTY 2026, which is the tax rate enacted by Act 53-2022 for calendar year 2026, and to require the company to reflect actual CNI rates for the post-2026 tax years through the Company's Rider "B" - State Tax Surcharge until the next rate case proceeding.

Q. WHAT IS THE IMPACT OF THIS ADJUSTMENT?

A. As reported in Table JBF-1, this adjustment would reduce the revenue requirement by $98,668 in FPFTY 2026.

Adjustments to the Common Equity Cost Rates

Q. WHAT IS THE PERFORMANCE FACTOR ADJUSTMENT?

A. Valley witness Edward E. Rogers explains that Section 523 of the Public Utility Code provides the Commission's guidelines for performance adjustments. He states that counsel has advised him that the Public Utility Code identifies several criteria to be considered in assessing the performance of a fixed utility for purposes of a performance factor adjustment, including consideration of any relevant and material evidence of efficiency, effectiveness, and adequacy of service. Mr. Rogers provides information on Valley's operations, which he asserts support receiving a performance factor adjustment.[4]

Q. WHAT IS VALLEY'S PROPOSED PERFORMANCE FACTOR ADJUSTMENT?

A. Valley proposes a performance factor adjustment of a 5-basis point addition to the cost of common equity.[5]

[4] Direct Testimony of Edward W. Rogers (Valley Statement No.4), pp. 9-11.
[5] Revised Direct Testimony of Dylan W. D'Ascendis (Joint Statement No. 2), page 52.

Q. WHAT IS YOUR RESPONSE TO VALLEY'S PROPOSED PERFORMANCE FACTOR ADJUSTMENT?

A. Utilities are expected to provide safe and reliable service to their customers. They should also deliver quality customer service, upgrade their systems, and manage their costs effectively. Utilities already receive a guaranteed rate of return for performing these functions. Providing an additional upward adjustment for effective operations, at the expense of customers, is excessive.

Q. WHAT IS THE SIZE ADJUSTMENT?

A. Valley witness Dylan D'Ascendis explains that the Companies' smaller size relative to the Gas Utility Proxy Group indicates greater relative business risk for the Company because, all else being equal, size has a material bearing on risk. He asserts that size affects business risk because smaller companies generally are less able to cope with significant events that affect sales, revenues and earnings. For example, smaller companies face more risk exposure to business cycles and economic conditions, both nationally and locally. Additionally, Mr. D'Ascendis states that the loss of revenue from a few larger customers would have a greater effect on a small company than on a bigger company with a larger, more diverse, customer base.[6]

Q. WHAT EXAMPLES OF SIZE RISK ARE PROVIDED BY VALLEY?

A. Valley cites the ability of many of its largest customers to switch from natural gas to a different fuel source as a risk that is enhanced by its small size. Valley witness Mr. Rogers states, "…our five largest customers represent approximately

[6] Revised Direct Testimony of Dylan W. D'Ascendis (Joint Statement No. 2), page 47.

32% of our annual distribution margins, and three of the five have dual-fuel capabilities…In addition to the largest customers, many of our other customers have access to potential alternatives to natural gas service, including propane, fuel oil, wood and electric."[7]

Q. WHAT IS VALLEY'S PROPOSED SIZE ADJUSTMENT?

A. Valley proposes a size factor adjustment of a 100-basis point addition to the cost of common equity.[8]

Q. WHAT IS YOUR RESPONSE TO VALLEY'S PROPOSED SIZE FACTOR ADJUSTMENT?

A. The Company's arguments for an upward adjustment focus only on potential losses, without acknowledging the possibility of potential gains. While it is true that a small company losing a large customer could experience reduced revenues, it is also possible for the company to gain large customers, therefore increasing revenues. At the very least, new customers could offset the impact of losing existing ones.

Also, Mr. Rogers' argument that a size factor adjustment is justified due to the risk of its largest customers switching from natural gas to other types of fuel is counter intuitive. Adding 100-basis points to the cost of common equity will increase the price of natural gas service, which in turn will increase the risk of fuel switching, resulting in the loss of customers.

Customers should not bear the burden of shielding a utility from every possible risk, particularly when utilities have the ability to file a rate case with the

[7] Direct Testimony of Edward E. Rogers (Valley Statement No. 4), page 8. [8] Direct Testimony of Howard S.

Gorman (Valley Statement No. 1), page 15.

Commission to address extreme risks if they arise. A 100-basis-point upward adjustment to account for unspecified risks, and likely even increase some of the risks, is excessive.

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE PERFORMANCE FACTOR ADJUSTMENT AND THE SIZE FACTOR ADJUSTMENT?

A. I recommend eliminating the performance factor adjustment entirely and lowering or removing the size factor adjustment. These changes support, and help justify, a lower return on equity ("ROE") for the company, which I will discuss in greater detail below.

Proxy Return on Equity Adjustment

Q. WHAT ROE IS VALLEY REQUESTING IN THIS PROCEEDING?

A. Valley witness Dylan W. D'Ascendis recommends a ROE of 11.65%.[9]

Q. DO YOU SUPPORT VALLEY'S REQUESTED ROE?

A. No.

Q. WHAT OBSERVATIONS HAVE YOU MADE IN REGARD TO VALLEY'S REQUESTED ROE?

A. A comparison of Valley's requested ROE of 11.65% with the most recent Report on the Quarterly Earnings of Jurisdictional Utilities for the year ending December 31, 2024, produced by the Bureau of Technical Utility Services indicates to me that the requested 11.65% is too high and should be adjusted down. Based on the

9 Revised Direct Testimony of Dylan W. D'Ascendis (Joint Statement No. 2), page 6.

report, the current market indicated ROE for natural gas utilities as calculated by the Bureau of Technical Utility Services should fall within the range of 8.92% to 12.05%[10]. This report is included as Exhibit JBF-1 at the end of my testimony.

A review of recently completed rate cases across the country for natural gas distribution companies that were either settled, or fully litigated within the last year, suggests that the proper ROE is likely near the lower part of the range provided by the Bureau of Technical Utility Services. The average authorized ROE in cases involving gas distribution companies that were approved between June 1, 2024, and June 30, 2025, is 9.70%. A detailed listing of approved ROE's from rate cases finalized over the last year is included at the end of my testimony as Exhibit JBF-2. I present the ROE's of a subset of natural gas distribution utility cases that were finalized in 2025 in Table JBF-4.

Table JBF-4
Survey of Approved ROE's for Natural Gas Distribution Companies
Between January 1, 2025 & June 30, 2025

State	Company	Case identification	Approved Date	ROE (%)
OR	Avista Corporation	D-UG-519	5/23/2025	9.50
VA	Columbia Gas of Virginia, Incorporated	C-PUR-2024-00030	5/15/2025	9.75
TX	Atmos Energy Corporation	D-OS-24-00018879	5/13/2025	9.80
MD	Columbia Gas of Maryland, Incorporated	C-9754	4/22/2025	9.80
VA	Roanoke Gas Company	C-PUR-2024-00006	4/10/2025	9.90
AZ	Southwest Gas Corporation	D-G-01551A-23-0341	3/27/2025	9.84
NY	Orange and Rockland Utilities, Inc.	C-24-G-0061	3/20/2025	9.75
WA	Cascade Natural Gas Corporation	D-UG-240008	2/24/2025	9.50
MN	Northern States Power Company	D-G-002/GR-23-413	2/13/2025	9.60
WA	Puget Sound Energy, Inc.	D-UG-240005	1/15/2025	9.90
NC	Piedmont Natural Gas Company, Inc.	D-G-9 Sub 837	1/7/2025	9.80
			Average	9.74

[10] Exhibit JBF-1, Report on the Quarterly Earnings of Jurisdictional Utilities (Year ending December 31, 2024, page 14.

Q. DO YOU RECOMMEND A SPECIFIC ROE?

A. No, I do not have a recommendation for a specific ROE but rather defer to analysis and recommendations promulgated by the Office of Consumer Advocate ("OCA") and the Bureau of Investigation and Enforcement ("I&E"). However, for purposes of my testimony, I have assumed a proxy 10.15% ROE based upon the Commission's approved ROE for Distribution System Improvement Charge (DSIC) included in the most recent Report on the Quarterly Earnings of Jurisdictional Utilities[11] for the year ended December 31, 2024 produced by the Bureau of Technical Utility Services referenced previously.

Q. WHAT IS THE REVENUE REQUIREMENT IMPACT OF USING A PROXY 10.15% ROE?

A. As reported in Table JBF-1, this adjustment would reduce revenue requirement by $185,644 in FPFTY 2026.

<u>Accounts 874 through 880, 889, 920, 932</u>

Q. DO O&M ACCOUNTS 874 THROUGH 880, 889, 920, AND 932 CONTAIN ERRORS IN VALLEY'S APPLICATION TO THE COMMISSION?

A. Yes, they do.

Q. PLEASE EXPLAIN.

A. In several responses to interrogatories posed by I&E in set I&E-RE, Valley stated, "An incorrect source document was inadvertently used for the 2025 expenses in Accounts 874 through 880, 889, 920, and 932. We are in the process of preparing

[11] Exhibit JBF-1, Report on the Quarterly Earnings of Jurisdictional Utilities (Year ending December 31, 2024, page 15.

revisions to Exhibit HSG-1 to correct this oversight, which we will send to the parties (and file with the Commission)."[12]

Q. HAVE YOU RECEIVED THE REVISED EXHIBIT HSG-1?

A. No, I have not. Intervening parties should have the ability to review and make recommended adjustments to those accounts once the revised Exhibit HSG-1 is available.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

[12] Valley Response to I&E-RE-30-D

APPENDIX A

Vitae & Expert Testimony List

of

Justin B. Farr

APPENDIX A

Justin B. Farr

Director, Energy Strategies, L.L.C.
111 East Broadway, Suite 1200, Salt Lake City, UT 84111
jfarr@energystrat.com

Vitae

Professional Experience

Energy Strategies, Salt Lake City UT, April 2022 - Present
An energy consulting firm focused on regulatory services, policy, and markets serving power producers, transmission developers, utilities, government agencies, NGO's, and large energy users

Director

- Perform energy-related economic and policy analysis, regulatory intervention, and strategic negations on behalf of industrial, commercial, and public sector interests
- Provide risk management and market fundamentals analysis to large consumers of natural gas
- Executive director of the Utah Association of Energy Users

PacifiCorp, Salt Lake City UT, January 2020 – April 2022
Berkshire Hathaway owned electric utility serving over 1.6 million customers in Utah, Oregon, Washington, Wyoming, Idaho, and parts of Northern California

Assistant Manager of Regulation, March 2021 – April 2022
Senior Fuels Manager, January 2020 – March 2021

- Performed rate projections tied to the company's 10-year plan
- Provided testimony on the Renewable Energy Credits balancing account
- Procured fuel and managed contracts for company owned and jointly owned thermal plants

Magnum Development, Holladay UT, 2017 – Oct 2019
Private Equity backed developer of utility-scale storage in underground salt caverns. Developing storage for natural gas, compressed air created from renewable electricity, green hydrogen, and helium.

Vice President of Financial Planning, January 2019 – October 2019
Assistant Vice President of Financial Planning, February 2017 – December 2018

- Worked on commercial team developing bidding strategies and analysis to support joint development negotiations

- Managed all financial and economic modeling across all of Magnum's business verticals including: Magnum Midstream (Natural Gas), Magnum Compressed Air Energy Storage (CAES), Magnum Hydrogen, and Magnum Industrial Gases (Helium)

PacifiCorp, Salt Lake City UT, 2013 – 2017
Berkshire Hathaway owned electric utility serving over 1.6 million customers in Utah, Oregon, Washington, Wyoming, Idaho, and parts of Northern California

Manager Economic & Financial Analysis, August 2015 – February 2017
Senior Financial Planning Analyst, October 2013 – August 2015

- Managed team of Sr. Financial Analysts responsible for economic analysis, internal audit of joint owned plants, and annual budget of resource development division
- Led team of engineers, plant managers, and vice presidents in developing economic solutions that optimized existing thermal and renewable infrastructure investment
- Developed economic models to explore new resource development opportunities such as utility scale solar and battery installations
- Prepared annual cost of generation report for senior management

Energy Strategies, Salt Lake City UT, 2005 – 2013
An energy consulting firm focused on regulatory services, policy, and markets serving power producers, transmission developers, utilities, government agencies, NGO's, and large energy users

Senior Consultant, January 2010 – October 2013
Consultant, July 2005 – December 2009

- Developed strategies for clients with energy infrastructure that optimized environmental performance and financial objectives while meeting their utility requirements
- Performed market studies focused on thermal & renewable energy need, transmission availability, pricing, and impacts of public policy initiatives. Studies were designed to inform and improve clients' energy decisions including risk management and procurement strategy.

Education

- Master of Business Administration, University of Utah, May 2005
- Bachelor of Science in Economics/Business Minor, University of Utah, May 2000
- Graduated Magna Cum Laude; GPA 3.92
- Honors at Entrance Scholarship; 1999-2000 Law & Economic Society Fellowship

Expert Testimony

"In the Matter of the Petition of PPL Electric Utilities Corp for Approval of its Second Distributed Energy Resources Management Plan," Public Utilities Commission of **Pennsylvania**, Docket No. P-2024-3049223. Direct testimony submitted September 17, 2024. Surrebuttal testimony filed January 22, 2024.

"In the Matter of the Verified Petition of Indiana Michigan Power Company for Approval of Modifications to its Industrial Power Tariff – Tariff IP," **Indiana** Utility Regulatory Commission, Cause No. 46097. Direct testimony submitted October 15, 2024. Cross-Answering testimony filed November 4, 2024. Settlement testimony filed December 4, 2024.

"In the Matter of the Application of Rocky Mountain Power for Authority to Revise Rates in Tariff Schedule 98, Renewable Energy Credits Balancing Account," **Utah** Public Service Commission, Docket No. 22-035-07. Direct testimony submitted March 15, 2022.

EXHIBIT JBF-1

PENNSYLVANIA PUBLIC UTILITY COMMISSION

Public Meeting held May 8, 2025

Docket Number: M-2025-3054401

BUREAU OF TECHNICAL UTILITY SERVICES

REPORT ON THE QUARTERLY EARNINGS

OF JURISDICTIONAL UTILITIES

FOR THE YEAR ENDED

December 31, 2024

Stephen M. DeFrank, Chairman
Kimberly Barrow, Vice Chair
Kathryn L. Zerfuss
John F. Coleman, Jr., Joint Statement, Dissenting
Ralph V. Yanora, Joint Statement, Dissenting

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This chart depicts the overall and equity returns (actual and adjusted) for the filing utilities for the current quarter. The last authorized equity returns and the year authorized is also shown.

Attachment C – Allowed Rates of Return on Common Equity..... 14
This is a historical chart that shows the most recent rate cases for select companies in electric, gas, and water. A docket number followed by their final return on equity and year is also given.

Attachment D – Distribution System Improvement Charge Return on Equity 15
Compares utility adjusted return on equity to Commission authorized return on equity for utilities with a Distribution System Improvement Charge.

Attachment E – Explanation of Return on Equity Methods 16
Criteria for determining the industry barometer groups used in ROE calculations. Also, provides details of the Discounted Cash Flow equation and Capital Asset Pricing Model equation.

Attachment F – Market Based Returns on Equity – Electric..... 18
The market indicated common equity cost rate range consists of data used from the electric barometer groups and is based on a series of calculations to average the DCF methods. Also, indicates Distribution System Improvement Charge Return.

Attachment F – Historic DCF and CAPM – Electric..... 19
Historic barometer group DCF and CAPM average ROEs.

Attachment F – Electric Barometer Group Calculation of a Current and 52 Week Average Dividend Yield..... 20-21
Electric barometer companies are used to calculate a current DCF in the first chart. The second chart demonstrates the companies 52-week average DCF. A final average of the two calculations is also shown at the bottom.

Attachment F – Development of a Representative Dividend Growth Rate..... 22
Multiple sources of the gas barometer companies projected 5-year Earnings Per Share are used to calculate the Group Average Dividend Growth Estimate.

Attachment G – Market Based Returns on Equity – Gas..... 23
The market indicated common equity cost rate range consists of data used from the gas barometer groups and is based on a series of calculations to average the DCF methods. Also, indicates Distribution System Improvement Charge Return.

Attachment G – Historic DCF and CAPM – Gas 24
Historic barometer group DCF and CAPM average ROEs, including a linear trend line graph.

Attachment G – Gas Barometer Group Calculation of a Current and 52 Week Average Dividend Yield 25
Gas barometer companies are used to calculate a current DCF in the first chart. The second chart demonstrates the companies 52-week average DCF. A final average of the two calculations is also shown at the bottom.

Attachment G – Development of a Representative Dividend Growth Rate 26
Multiple sources of the gas barometer companies projected 5-year Earnings Per Share are used to calculate the Group Average Dividend Growth Estimate.

Attachment H – Market Based Returns on Equity – Water 27
The market indicated common equity cost rate range consists of data used from the water barometer groups and is based on a series of calculations to average the DCF methods. Also, indicates Distribution System Improvement Charge Return.

Attachment H – Historic DCF and CAPM – Water 28
Historic barometer group DCF and CAPM average ROEs, including a linear trend line graph.

Attachment H – Water Barometer Group Calculation of a Current and 52 Week Average Dividend Yield 29
Water barometer companies are used to calculate a current DCF in the first chart. The second chart demonstrates the companies 52-week average DCF. A final average of the two calculations is also shown at the bottom.

Attachment H – Development of a Representative Dividend Growth Rate 30
Multiple sources of the water barometer companies projected 5-year Earnings Per Share are used to calculate the Group Average Dividend Growth Estimate.

Introduction:

On September 20, 1991, the Commission initiated a rulemaking at L-00910061 pertaining to earnings disclosures by the public utilities subject to its jurisdiction. At that docket, the Commission stated that the submission of accurate, reliable, and complete earnings disclosure reports, at regular intervals, is essential to the fulfillment of the broad regulatory oversight responsibilities entrusted to the Commission by the Legislature in the Public Utility Code. The earnings disclosure regulations promulgated by the Commission were adopted October 1, 1992, and published January 23, 1993, at 23 Pa.B. 463. Based upon those regulations, codified at 52 Pa. Code, Chapter 71, a reporting format was developed and distributed to the jurisdictional fixed utilities of Pennsylvania.

All fixed utilities having jurisdictional revenues of $1,000,000 or more, for a calendar year, are required to file the report by March 31 of each year. Such reports are to be based upon the results of operations for the 12-month period ending December 31 of the prior year. Utilities having more than $10,000,000 in jurisdictional revenues are also required to file reports for the 12 months ending on March 31, June 30, and September 30 of each year.[1] On November 30, 2004, however, the Pennsylvania General Assembly signed into law Act 183 concerning alternative telecommunications regulation and broadband deployment. As a result of Act 183, the reporting requirements for the PUC jurisdictional telecommunications companies of Pennsylvania have been streamlined at section 3015(e) of the Public Utility Code. A quarterly earnings report is not listed among those reports now required of PUC jurisdictional telecommunications utilities in Pennsylvania and, therefore, this report does not address telephone company earnings.

The reports have been filed for the period ending December 31, 2024, at Docket No. M-2025-3052807.[2] The Finance Staff of the Bureau of Technical Utility Services has reviewed the reports and has prepared this summary report for public release. This report sets forth the achieved return on equity for each company, the last allowed return for that utility, a market return as determined through the analysis of the barometer group data and the most recent returns allowed, per industry, by the Pennsylvania Public Utility Commission and by other regulatory bodies. Where a utility has not filed a report, the reasons for not filing are indicated.

Questions pertaining to the preparation and contents of this Report should be directed to Mr. Marc Hoffer, Manager - Finance, Bureau of Technical Utility Services, at (717) 787-1869.

[1] Per Commission regulations at 52 Pa. Code § 71.3(a)(1), the major electric utilities are specifically identified by name rather than utilizing the $10,000,000 revenue threshold utilized by gas and water utilities.

[2] Columbia Gas of PA Inc., UGI Utilities, Inc. – Gas Division, and FirstEnergy Pennsylvania Electric Co. have rate filings at Docket Nos. R-2025-3053499, R-2024-3052716, and R-2024-3047068, respectively, and have filed a letter with the Secretary in place of a report in accordance with 52 Pa. Code § 71.4.

Attachment A

The equity return summaries that follow in Attachment A are, for each quarter;

ACTUAL

1. Based on actual results of operations

and

ADJUSTED

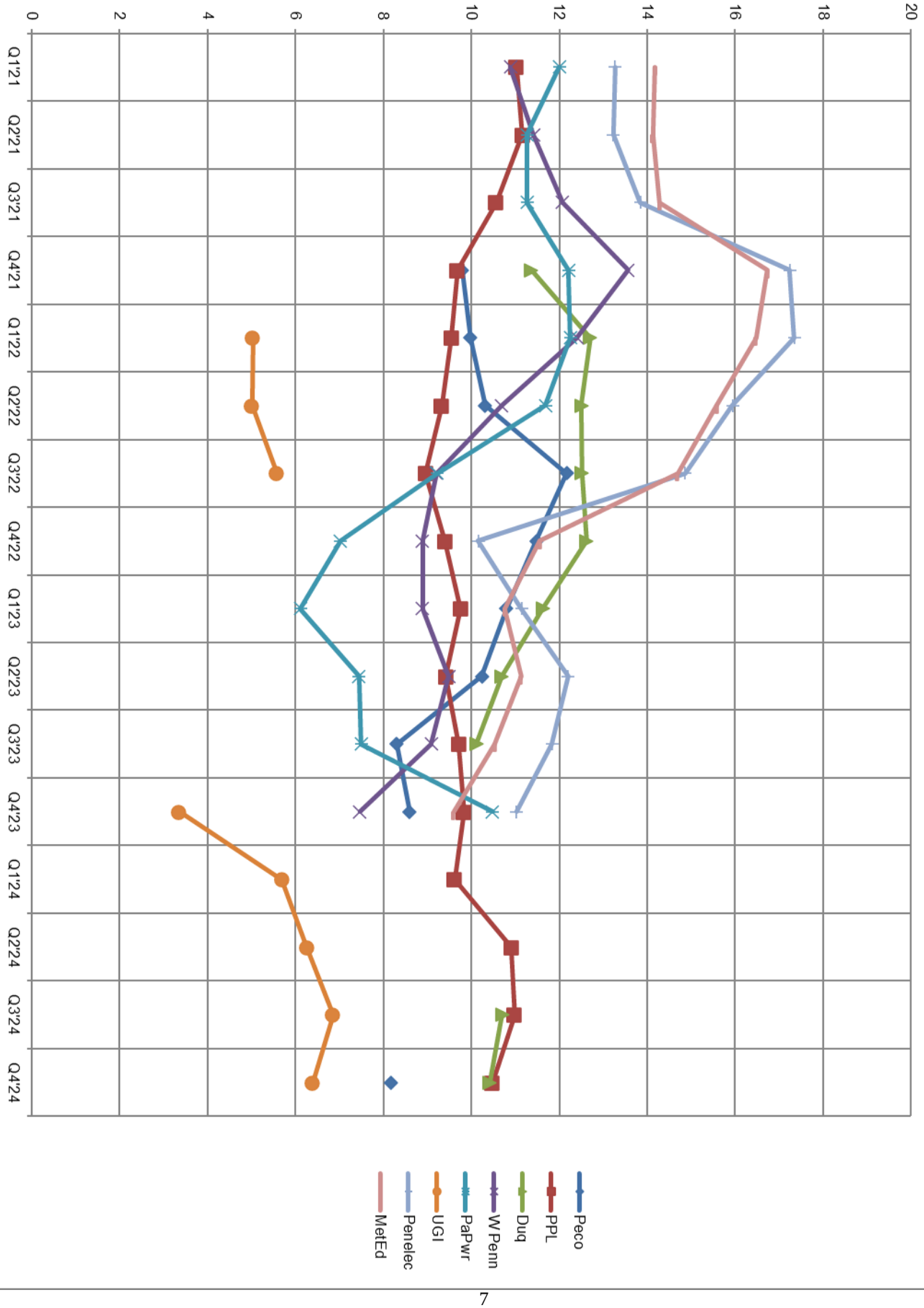
2. Based on company proposed pro forma and ratemaking adjustments

Attachment A

ELECTRIC UTILITIES
EQUITY RETURNS BY QUARTER

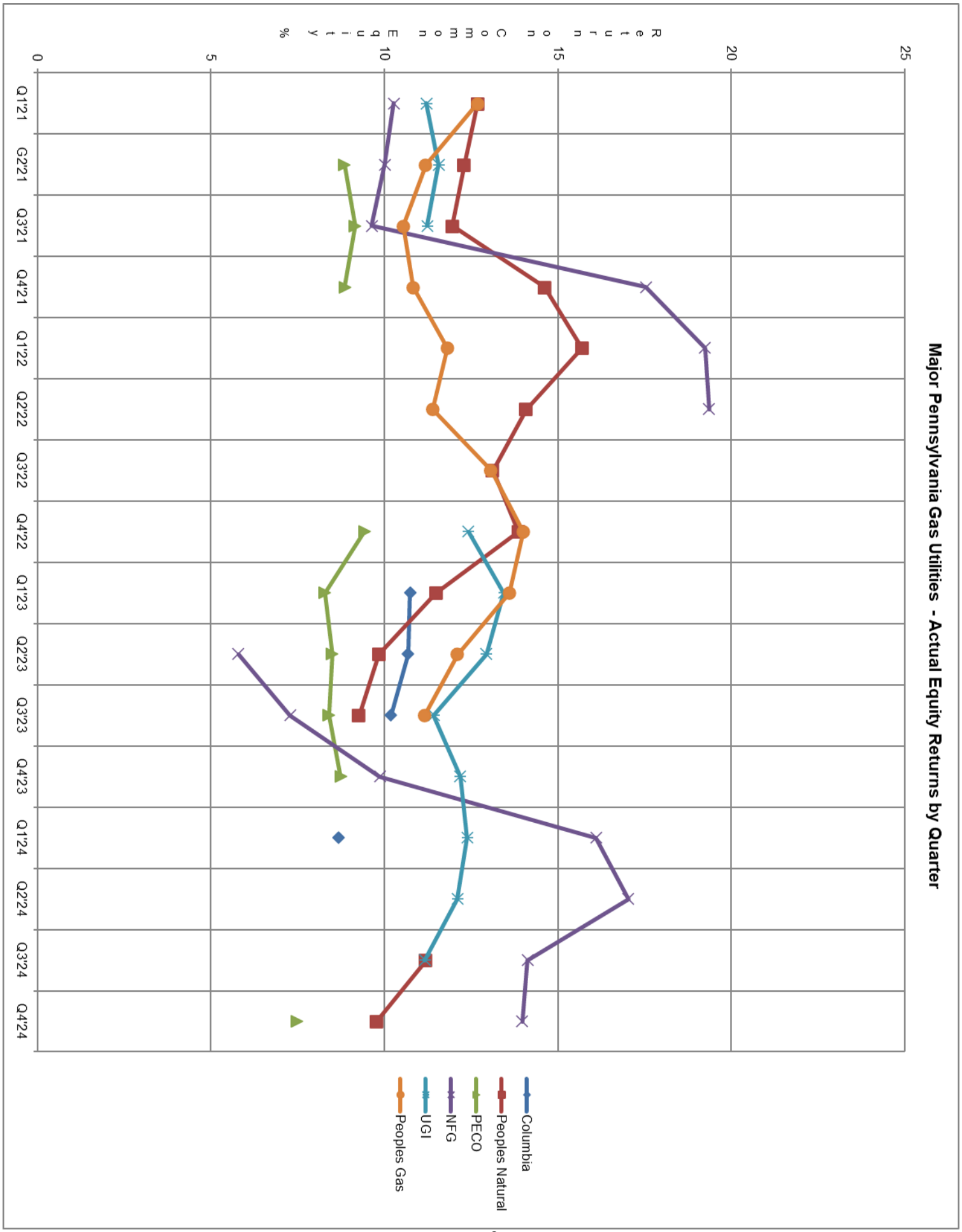
QTR END		Peco		PPL		Duq		W Penn		PaPwr		UGI		Penelec		MetEd	
		ACT	ADJ	ACT	ADJ	ACT	ADJ	ACT	ADJ	ACT	ADJ	ACT	ADJ	ACT	ADJ	ACT	ADJ
2018	1			12.53	11.36			10.35	9.08	9.03	8.08			11.84	9.93	12.77	11.38
	2			11.05	9.49			9.92	8.52	8.79	7.57			11.56	9.39	11.90	10.26
	3			11.19	9.83			11.41	6.74	10.30	5.80			13.97	8.44	14.46	9.62
	4	10.88	7.61	11.10	10.15	12.06	9.39	9.92	6.78	10.64	7.43			13.27	9.31	13.05	7.40
2019	1	12.65	7.93	10.10	8.96	12.58	9.73	9.08	6.62	9.14	7.61	7.05	5.22	12.03	8.07	12.54	7.66
	2	12.34	7.94	10.51	8.95	12.38	9.34	8.02	5.99	8.29	7.10	5.77	3.22	11.42	8.16	11.72	7.21
	3	12.49	7.96	10.61	8.99	13.88	9.33	9.90	7.87	9.28	7.76	6.20	2.04	11.26	8.78	12.25	7.77
	4	12.21	8.50	10.53	10.40	13.92	9.08	14.13	7.07	8.08	6.90	7.20	2.38	10.02	8.54	10.96	9.27
2020	1	11.31	8.35	10.84	11.20	12.66	8.31	9.82	5.54	5.06	6.71	5.43	2.26	7.24	8.74	7.20	8.31
	2	9.38	8.17	11.20	10.81	12.73	8.56	10.41	5.53	5.56	6.55	6.06	2.01	6.68	7.94	7.34	8.04
	3	9.62	8.56	11.14	11.20	12.32	8.08	10.22	5.42	5.62	6.74	7.76	0.41	7.87	8.75	7.64	8.37
	4	9.16	7.64	11.10	11.48	12.57	8.15	7.48	5.65	11.36	7.34			10.08	8.62	9.91	8.64
2021	1			11.03	11.76			10.89	6.64	12.01	7.01			13.27	8.96	14.19	9.44
	2			11.17	11.73			11.42	7.07	11.27	5.94			13.23	8.15	14.13	9.06
	3			10.57	10.65			12.08	7.91	11.27	5.91			13.85	8.67	14.29	9.38
	4	9.79	7.59	9.69	10.57	11.37	11.23	13.57	7.85	12.21	5.42			17.25	8.04	16.74	9.40
2022	1	9.98	6.99	9.55	9.49	12.71	10.91	12.40	6.99	12.26	5.30	5.03	4.93	17.35	7.83	16.48	9.40
	2	10.32	7.19	9.33	9.54	12.51	10.22	10.70	5.78	11.69	5.04	5.01	3.89	15.95	6.93	15.59	8.72
	3	12.17	7.42	8.97	9.14	12.52	9.74	9.21	4.43	9.23	4.35	5.58	0.65	14.87	5.88	14.70	7.57
	4	11.48	6.59	9.41	9.18	12.62	9.54	8.89	4.19	7.03	3.44			10.16	5.07	11.56	7.55
2023	1	10.80	6.47	9.76	9.36	11.63	9.53	8.89	5.32	6.11	4.01			11.15	6.88	10.77	8.25
	2	10.24	6.19	9.43	8.67	10.69	9.39	9.49	6.03	7.45	5.58			12.20	7.90	11.14	8.81
	3	8.30	5.48	9.72	8.12	10.12	8.89	9.09	5.96	7.50	5.76			11.84	7.79	10.54	8.60
	4	8.60	5.19	9.84	8.49			7.47	6.02	10.49	7.09	3.36	4.48	11.03	8.17	9.61	8.66
2024	1			9.63	8.22							5.70	2.03				
	2			10.92	9.17							6.26	1.11				
	3			10.99	9.46	10.71	9.16					6.86	1.70				
	4	8.17	4.22	10.49	7.23	10.42	9.38					6.40	1.41				

Major Pennsylvania Electric Utilities - Actual Equity Returns by Quarter



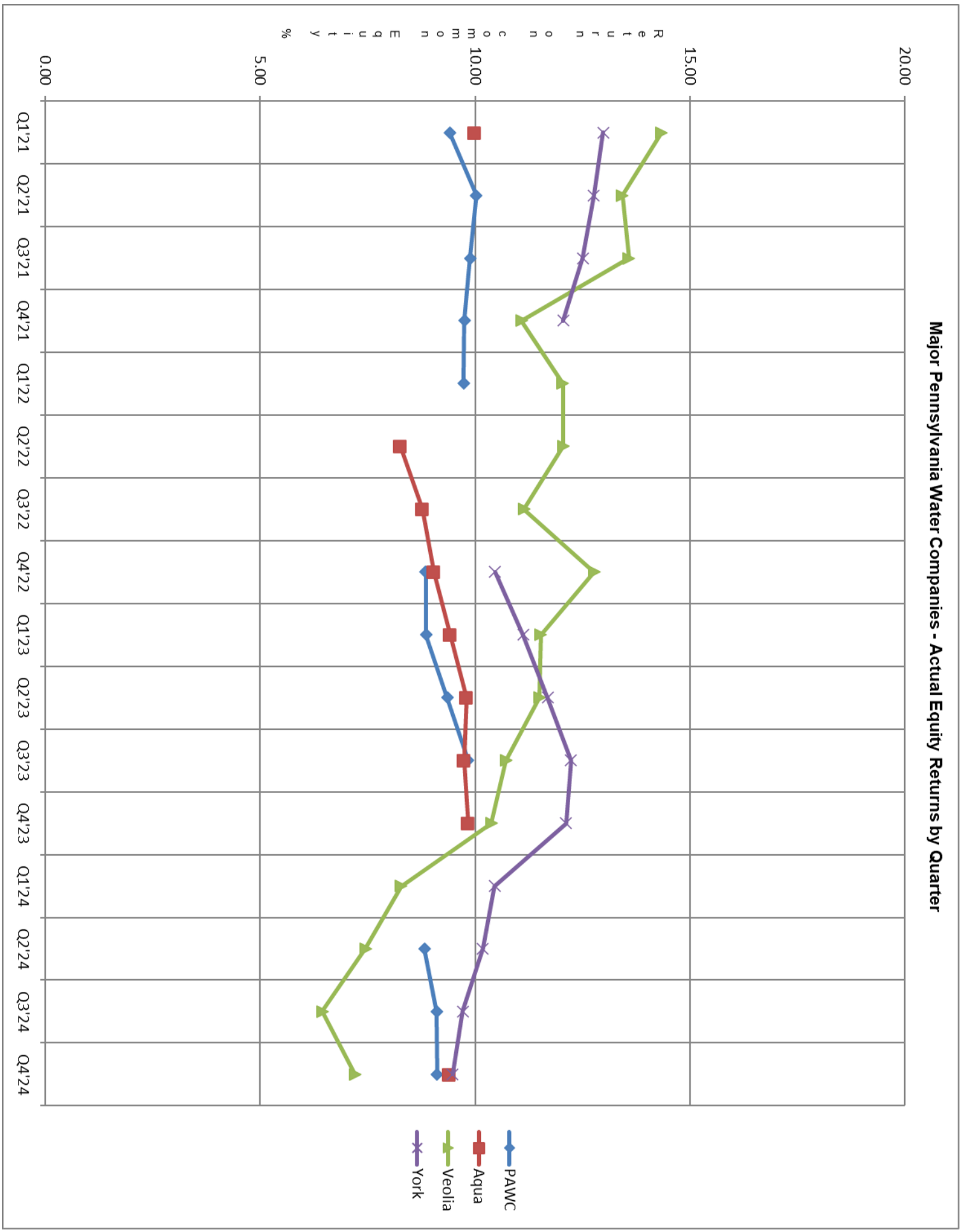
GAS UTILITIES
EQUITY RETURNS BY QUARTER

QTR		Columbia		Peoples Natural		PECO		NFG		UGI		Peoples Gas	
END		ACT	ADJ	ACT	ADJ	ACT	ADJ	ACT	ADJ	ACT	ADJ	ACT	ADJ
2018	1			11.42	7.00	12.65	9.77	14.40	10.20	12.82	7.90	14.02	10.17
	2			11.03	6.80	12.66	9.05	12.06	9.89	16.75	6.80	12.78	10.15
	3			10.21	7.43	12.54	8.36	12.52	10.12	18.69	8.04	13.03	10.20
	4	11.39	9.81			12.86	8.68	12.24	10.21			13.92	11.13
2019	1	12.76	10.22			13.68	9.06	11.83	10.93			14.10	10.71
	2	12.04	9.92			12.62	8.41	14.56	9.99			13.80	11.66
	3	11.77	9.85			12.40	8.31	14.17	9.75			14.02	11.63
	4	9.21	9.09	10.74	12.26	11.75	6.99	14.20	9.77			12.76	11.20
2020	1	8.42	9.11	12.34	12.34	10.84	7.68	11.82	9.92			11.40	11.07
	2			13.81	12.38	11.26	7.25	11.28	9.05			11.89	11.10
	3			14.60	12.77			10.39	8.25			11.82	11.50
	4			12.09	10.37			9.68	8.12			12.93	12.11
2021	1			12.69	10.43			10.27	8.47	11.22	7.70	12.69	11.76
	2			12.31	10.23	8.85	5.13	10.02	8.47	11.57	8.04	11.20	11.61
	3			11.97	10.27	9.16	5.27	9.64	8.45	11.24	6.97	10.56	11.38
	4			14.62	10.52	8.86	5.79	17.54	8.02			10.84	10.28
2022	1			15.71	10.93			19.24	7.88			11.83	12.09
	2			14.09	11.67			19.36	6.87			11.40	12.19
	3			13.13	10.30							13.08	11.31
	4			13.87	10.56	9.43	5.93			12.42	7.62	14.01	14.19
2023	1	10.75	10.30	11.50	9.02	8.29	6.05			13.45	8.33	13.61	12.68
	2	10.68	10.33	9.85	9.50	8.50	6.20	5.80	9.98	12.94	8.97	12.12	13.84
	3	10.19	10.72	9.28	8.17	8.41	6.01	7.29	9.58	11.43	8.27	11.17	14.22
	4					8.75	6.82	9.87	10.80	12.19	7.44		
2024	1	8.67	9.61					16.10	10.64	12.39	7.55		
	2							17.03	9.78	12.11	6.91		
	3			11.20	9.07			14.13	8.63	11.17	6.45		
	4			9.78	8.84	7.49	5.56	13.98	8.62				


Major Pennsylvania Gas Utilities - Actual Equity Returns by Quarter
Return on Common Equity %
0
5
10
15
20
25
Q1'21
Q2'21
Q3'21
Q4'21
Q1'22
Q2'22
Q3'22
Q4'22
Q1'23
Q2'23
Q3'23
Q4'23
Q1'24
Q2'24
Q3'24
Q4'24
Columbia
Peoples Natural
PECO
NFG
UGI
Peoples Gas

WATER UTILITIES
EQUITY RETURNS BY QUARTER

QTR		PAWC		Aqua		Veolia		York	
END		ACT	ADJ	ACT	ADJ	ACT	ADJ	ACT	ADJ
2018	1	9.55	8.97	10.94	8.41				
	2	10.27	9.65						
	3	11.03	9.48						
	4	10.08	9.03					10.70	10.30
2019	1	9.82	8.87					11.60	11.60
	2	9.72	8.90	9.84	9.04	10.78	10.36	11.80	11.80
	3	9.13	8.41	10.69	8.84	11.55	11.75	12.00	12.00
	4	8.71	8.09	10.33	8.24	11.80	12.15	12.00	9.80
2020	1	8.74	7.56	10.47	8.31	11.30	11.30	12.39	12.39
	2			10.81	8.57	10.72	10.69	12.51	12.51
	3			10.33	8.55	11.13	10.69	13.76	13.76
	4	8.90	8.15	9.89	8.30	13.98	10.17	13.42	9.94
2021	1	9.41	8.90	9.99	8.38	14.34	10.48	12.98	9.74
	2	10.03	9.28			13.43	9.83	12.76	9.66
	3	9.89	8.65			13.58	9.07	12.51	9.32
	4	9.75	8.05			11.08	9.75	12.05	8.86
2022	1	9.73	7.82			12.04	9.68		
	2			8.26	8.91	12.05	9.79		
	3			8.78	8.85	11.14	9.30		
	4	8.85	8.97	9.04	8.88	12.77	9.49	10.47	10.57
2023	1	8.86	8.90	9.42	8.48	11.53	8.98	11.12	11.12
	2	9.35	8.89	9.80	8.52	11.50	8.91	11.69	11.69
	3	9.84	8.93	9.74	8.39	10.72	8.42	12.23	12.23
	4			9.84	8.35	10.38	7.64	12.12	8.16
2024	1					8.28	6.49	10.46	7.99
	2	8.82	8.56			7.46	5.70	10.18	8.00
	3	9.11	8.49			6.45	5.42	9.72	7.31
	4	9.12	8.44	9.40	9.29	7.21	5.36	9.48	7.10


Major Pennsylvania Water Companies - Actual Equity Returns by Quarter
Return on Common Equity %
20.00
15.00
10.00
5.00
0.00
Q1'21
Q2'21
Q3'21
Q4'21
Q1'22
Q2'22
Q3'22
Q4'22
Q1'23
Q2'23
Q3'23
Q4'23
Q1'24
Q2'24
Q3'24
Q4'24
PAWC
Aqua
Veolia
York

Attachment B includes:

A. Overall Returns on rate base
1. Actual
2. Company proposed pro forma and ratemaking adjustments

and

B. Equity Returns
1. Actual
2. Company proposed pro forma and ratemaking adjustments

Summary of Returns
For the Year Ended December 31, 2024

COMPANY NAME	OVERALL RETURN ACTUAL	OVERALL RETURN ADJ	EQUITY RETURN ACTUAL	EQUITY RETURN ADJ	ROE AUTH	YEAR AUTH
ELECTRIC						
Major Electric Utilities						
PECO Energy - Electric Operations	6.31	4.10	8.17	4.22	Settled	2024
PPL Electric Utilities Corp.	7.99	6.06	10.49	7.23	Settled	2015
Duquesne Light Company	7.89	7.24	10.42	9.38	Settled	2024
West Penn Power Company*					Settled	2024
Pennsylvania Power Company*					Settled	2024
UGI Utilities, Inc. - Electric Division	5.57	3.18	6.40	1.41	Settled	2023
Pennsylvania Electric Company*					Settled	2024
Metropolitan Edison Company *					Settled	2024
Over $1,000,000						
Revenues						
Pike County Light & Power Co.	6.21	6.21	5.98	5.98	Settled	2021
Citizens Electric Company	6.30	8.03	6.58	8.54	Settled	2022
Wellsboro Electric Company	4.59	4.59	4.67	4.67	9.31	2020
GAS						
$10,000,000 Revenues						
Columbia Gas of PA, Inc.*					Settled	2024
Peoples Natural Gas Company LLC	7.14	6.31	9.78	8.84	Settled	2024
PECO Energy - Gas Operations	6.06	4.93	7.49	5.56	Settled	2024
National Fuel Gas Distribution Co.	10.04	7.11	13.98	8.62	Settled	2023
UGI Utilities, Inc. – Gas Division*					Settled	2022
Valley Energy Inc. of PA	3.89	3.97	3.40	3.51	Settled	2022
$1,000,000 to $10,000,000						
Revenues						
Pike County Light & Power Co.	2.39	2.39	-1.16	-1.16	Settled	2021
Leatherstocking Gas Company	2.15	2.15	-3.47	-3.47	Settled	2023
North East Heat and Light Company	4.25	4.25	4.35	4.37	11.00	2008
WATER						
$10,000,000 Revenues						
PA American Water Company	7.08	6.70	9.12	8.44	9.45	2024
Aqua Pennsylvania	7.03	6.92	9.40	9.29	Settled	2025
York Water Company	7.30	6.00	9.48	7.10	Settled	2023
Veolia Water Pennsylvania, Inc.	5.90	4.94	7.21	5.36	Settled	2024
$1,000,000 to $10,000,000						
Revenues						
Newtown Artesian Water Co.	5.56	3.35	6.29	2.52	Settled	2025
Columbia Water Company	6.27	6.27	6.86	6.86	9.75	2024
York Water Company – Wastewater	1.30	0.40	-0.30	-2.10	Settled	2023
Community Utilities – Water	2.56	2.56	0.44	0.44	Settled	2022
Community Utilities – Wastewater	4.12	4.12	3.24	3.24	Settled	2022
CAN DO Inc. – Water	1.99	1.99	2.46	2.46	Settled	2024
CAN DO Inc. – Wastewater	22.76	22.76	25.93	25.93	Settled	2024

*Columbia Gas of PA Inc., UGI Utilities, Inc. – Gas Division, and FirstEnergy Pennsylvania Electric Co. have rate filings at Docket Nos. R-2025-3053499, R-2024-3052716, and R-2024-3047068, respectively, and have filed a letter with the Secretary in place of a report in accordance with 52 Pa. Code § 71.4.

ALLOWED RATES OF RETURN ON COMMON EQUITY

This is a historical chart that shows the most recent rate cases for select companies in electric, gas, and water. A docket number followed by their final return on equity and year is also given.

ELECTRIC	**Docket Number**	**ROE (%)**	**Year**
Recent PA PUC Allowed			
UGI Utilities, Inc. – Electric	R-2022-3037368	Settled	2023
Duquesne Light Company	R-2024-3046523	Settled	2024
PECO Energy – Electric	R-2024-3046931	Settled	2024
PPL Electric Utilities Corp.	R-2015-2469275	Settled	2015
Pennsylvania Electric Company	R-2024-3047068	Settled	2024
Metropolitan Edison Company	R-2024-3047068	Settled	2024
Pennsylvania Power Company	R-2024-3047068	Settled	2024
West Penn Power Company	R-2024-3047068	Settled	2024
Current Market Indicated ROE as calculated by the Bureau of Technical Utility Services.			**9.17-11.23**

GAS			
Recent PA PUC Allowed			
National Fuel Gas Distribution Corp.	R-2022-3035730	Settled	2023
Columbia Gas of Pennsylvania, Inc.	R-2024-3046519	Settled	2024
PECO Energy – Gas	R-2024-3046932	Settled	2024
UGI Utilities, Inc. – Gas	R-2021-3030218	Settled	2022
Peoples Natural Gas Company	R-2023-3044549	Settled	2024
Current Market Indicated ROE as calculated by the Bureau of Technical Utility Services.			**8.92-12.05**

WATER			
Recent PA PUC Allowed			
Columbia Water	R-2023-3040258	9.75	2024
PA American Water	R-2023-3043189	9.45	2024
York Water	R-2022-3031340	Settled	2023
Aqua Pennsylvania	R-2024-3047822	Settled	2025
Veolia Water Pennsylvania	R-2024-3045192	Settled	2024
Current Market Indicated ROE as calculated by the Bureau of Technical Utility Services.			**7.25-12.59**

Distribution System Improvement Charge (DSIC) Eligible Utilities
Return on Equity (ROE) Summary

	Utility Adjusted ROE[3] (%)	Commission Approved ROE[4] (%)
ELECTRIC		
PECO Energy – Electric Operations	4.22	10.00
PPL Electric Utilities Corp.	7.23	10.00
Duquesne Light Company	9.38	10.00
West Penn Power Company*		10.00
Pennsylvania Power Company*		10.00
Pennsylvania Electric Company*		10.00
Metropolitan Edison Company*		10.00
UGI Utilities, Inc.- Electric Division	1.41	10.00
Pike County Light & Power Co.	5.98	10.00
GAS		
Columbia Gas of PA, Inc.*		10.15
Peoples Natural Gas Company LLC	8.84	10.15
PECO Energy – Gas Operations	5.56	10.15
UGI Utilities, Inc. – Gas Division*		10.15
Pike County Light & Power Co.	-1.16	10.15
National Fuel Gas Distribution Corp	8.62	10.15
WATER		
PA American Water Company	8.44	9.45
PA American – Wastewater	8.44	9.45
AQUA Pennsylvania	9.29	9.75
AQUA Pennsylvania – Wastewater	9.29	9.75
York Water Company	7.10	9.75
Veolia Water Pennsylvania, Inc.	5.36	9.75
Columbia Water Company	6.86	9.75
Newtown Artesian Water	2.52	9.75

* Columbia Gas of PA Inc., UGI Utilities, Inc. – Gas Division, and FirstEnergy Pennsylvania Electric Co. have rate filings at Docket Nos. R-2025-3053499, R-2024-3052716, and R-2024-3047068, respectively, and have filed a letter with the Secretary in place of a report in accordance with 52 Pa. Code § 71.4.

3 Each utility lists adjustments on Schedule B of their quarterly financial report.
4 The ROE is approved in a utility's most recent fully litigated base rate proceeding for hich a final order was entered not more than two years prior to the effective date of the DSIC. If more than two years have elapsed between the entry of a final order and the DSIC effective date, the ROE is from this report. If the base rate proceeding is settled, without a stipulated ROE, the ROE is from this report.

Explanation of Discounted Cash Flow (DCF) and Capital Asset Pricing Model (CAPM)

Barometer Group Criteria

The criteria used for determining the industry barometer groups used to calculate ROEs in this report are as follows:

- 50% or more of the company's assets must be related to the jurisdictional utility industry;
- The company's stock must be publicly traded and must have at least three years of earnings history;
- Companies targeted by merger and acquisition (M&A) activity will be excluded; companies involved in M&A activity may be excluded;
- Investment information for the company must be available to the Commission from more than one source;
- The barometer group companies must have an investment grade credit rating (S&P BBB- or better, Moody's Baa3 or better); and
- Geographic Regions:
  EDCs: *Value Line* Investment Survey's East, Central, and West Group Electric Utility companies;
  NGDCs: *Value Line* Investment Survey's Natural Gas Utility industry group companies;
  Water/Wastewater: *Value Line* Investment Survey's Water Utility industry group companies.

The barometer group companies are reviewed by staff on a quarterly basis and make any changes to these companies based upon the criteria above.

ROE Calculations

The Commission consistently uses the DCF model to determine the appropriate cost of equity for utilities. In this report, the DSIC ROE is calculated using two DCF models.

TUS uses the following formula to calculate the current dividend DCF: $K = D_1/P_0 + G$

TUS uses the following formula to calculate the 52-week average dividend DCF: $K = D_0/P_a + G$

Definitions:

K	=	Cost of equity
D_1	=	Dividend expected during the year
	=	$D_0 + ½g$
D_0	=	Latest indicated dividend, obtained from Yahoo! Finance
g	=	Expected 5-year dividend growth rate of barometer group obtained from Value Line Investment Survey.
P_0	=	Current price of the stock, obtained from Yahoo! Finance
P_a	=	Average of high and low stock price over the latest 52-week period, obtained from Yahoo! Finance
G	=	Average of 5-year expected earnings growth rate forecasts obtained from Value Line, Zacks Investment Survey, and S&P Capital IQ.

The CAPM uses the yield of a risk-free interest-bearing obligation plus a rate of return premium that is proportional to the systematic risk of an investment.

TUS uses the following formula to calculate CAPM: $K = R_f + \beta(R_m - R_f)$

Three components are necessary to calculate the CAPM cost of equity:

β	=	Beta, a measure of systematic risk for each stock
R_f	=	The risk-free rate of return, 10-year U.S. Treasury yields are used for R_f. Yields are taken from the previous two quarters and forecasted next four quarters.
R_m	=	Total return of the equity market as determined by Kroll

The Commission determines the ROE used for DSIC purposes based on the range of reasonableness from the DCF barometer group data, CAPM data, recent ROE adjudicated by the Commission, and informed judgment.

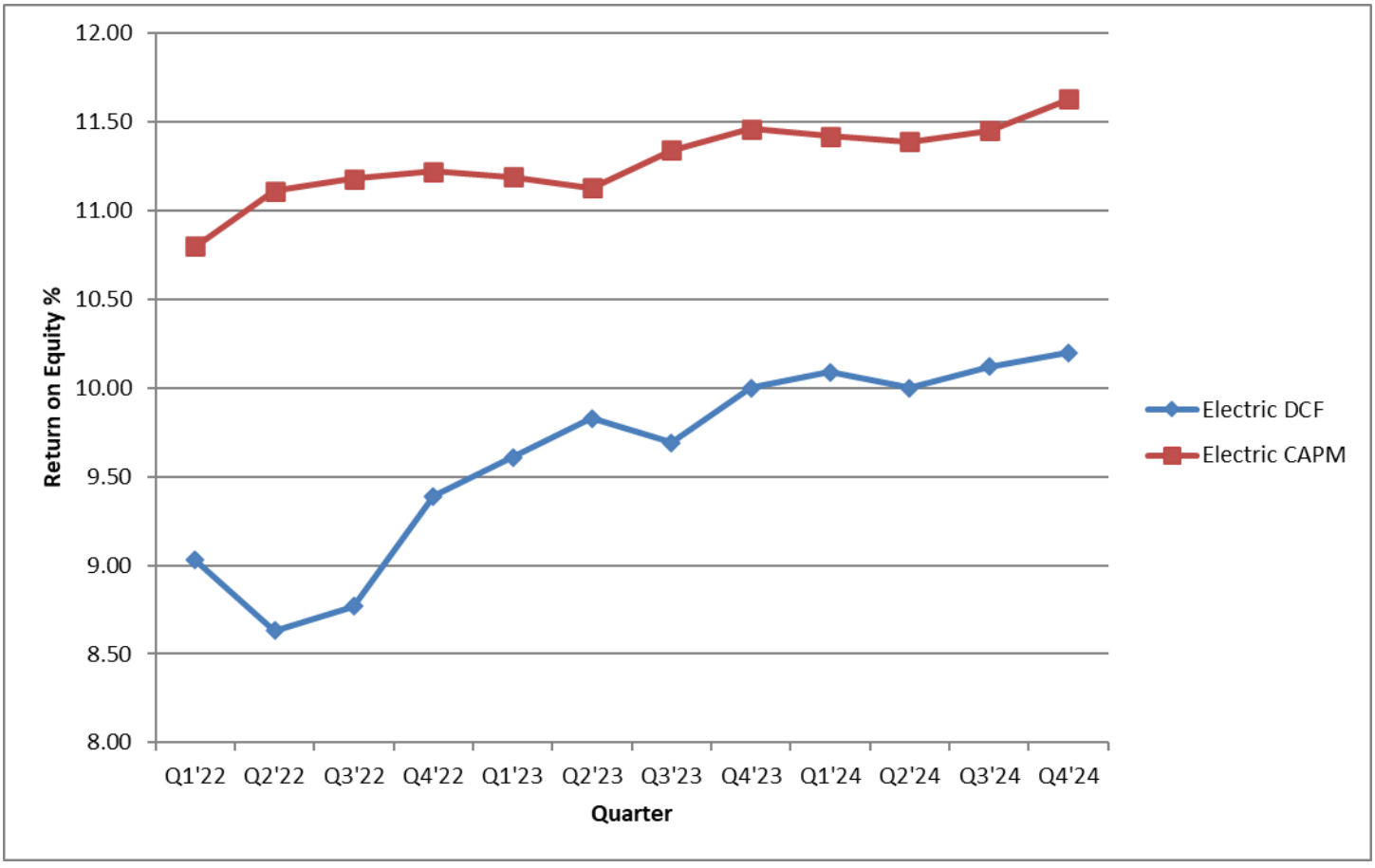
The market indicated common equity cost rate range consists of data used from the barometer groups and is based on a series of calculations to average the DCF methods.

Market Based Returns on Common Equity[1]	
April 7, 2025	
Electric Company Barometer Group	
	Cost Rates
	%
(1) Current DCF:	10.23
(2) 52-Week Average DCF:	10.18
(3) Overall DCF ((1) + (2)) / 2 :	10.20
(4) Market Indicated Common Equity Cost Rate Range:	9.17-11.23
(5) CAPM Check of DCF Reasonableness:	11.63
(6) Recent Commission Approved ROEs[3]:	*
*None within the last two years	
(7) Distribution System Improvement Charge (DSIC) Return[4]:	**10.00%**
[1] As calculated by the Bureau of Technical Utility Services	
[2] Standard Deviation of 58 DCF observations	
[3] Base rate case ROEs within last two years, fully litigated or stipulated for DSIC purposes	
[4] Commission authorized Return on Equity (ROE) for DSIC purposes	
Any questions concerning DSIC should be directed to Rich Layton	
of the Bureau of Technical Utility Services at (717) 214-9117.	

Historic Electric Industry Barometer Group DCF and CAPM Average ROEs

Electric		
	DCF	CAPM
Q1'22	9.03	10.80
Q2'22	8.63	11.11
Q3'22	8.77	11.18
Q4'22	9.39	11.22
Q1'23	9.61	11.19
Q2'23	9.83	11.13
Q3'23	9.69	11.34
Q4'23	10.00	11.46
Q1'24	10.09	11.42
Q2'24	10.00	11.39
Q3'24	10.12	11.45
Q4'24	10.20	11.63

Chart of Historic Electric Industry DCF and CAPM Average ROEs



Barometer electric companies are used to calculate a current DCF in the first chart. The second chart demonstrates the companies' 52-week average DCF. A final average of the two calculations is also shown at the bottom.

Electric Company Barometer Group
Calculation of a Current Dividend Yield

	Closing Market Price (Po) 4/7/2025 ($)	Latest Indicated Dividend (Do) ($)	Ind. Div. Plus 1/2 Div. Growth Rate (D1) ($)	Current Dividend Yield(D1/Po) (%)	DCF (%)
Alliant Energy Corp	59.81	2.03	2.09	3.50	10.00
Ameren Corp	94.34	2.84	2.93	3.11	9.80
American Electric Power	101.57	3.72	3.82	3.76	10.26
Avista Corp	39.56	1.96	2.00	5.05	10.71
CenterPoint Energy	35.50	0.88	0.91	2.55	9.88
CMS Energy Corp	70.94	2.17	2.22	3.14	10.13
Consolidated Edison	105.40	3.40	3.47	3.29	9.13
Dominion Energy	50.83	2.67	2.68	5.27	8.77
DTE Energy Company	127.95	4.36	4.46	3.48	11.47
Duke Energy Company	116.86	4.18	4.25	3.64	9.85
Edison International	53.62	3.31	3.41	6.36	13.94
Entergy Corp.	79.34	2.40	2.47	3.11	12.30
Evergy Inc	64.36	2.67	2.76	4.29	10.60
Eversource Energy	55.56	3.01	3.10	5.58	11.16
Exelon Corporation	44.69	1.60	1.60	3.58	9.63
FirstEnergy Corp	38.71	1.78	1.83	4.72	10.89
IDACORP, Inc..	113.75	3.44	3.53	3.11	10.71
MGE Energy, Inc.	87.02	1.80	1.86	2.14	9.14
NextEra Energy, Inc.	65.06	2.27	2.38	3.65	11.46
NorthWestern Corp	54.72	2.64	2.66	4.86	10.37
OGE Energy Corp	42.24	1.69	1.72	4.06	10.23
Otter Tail Corp	75.27	2.10	2.17	2.89	9.24
PPL Corporation	33.52	1.09	1.09	3.24	10.42
TXNM Energy Inc.	49.78	1.63	1.67	3.36	8.64
Pinnacle West Capital Corp	89.62	3.58	3.61	4.02	8.92
Portland General Electric Co.	41.58	2.00	2.06	4.94	9.91
Public Service Enterprise Group	77.13	2.52	2.60	3.37	9.95
Southern Company	87.22	2.88	2.93	3.36	9.80
Xcel Energy Inc.	67.06	2.28	2.35	3.50	10.49
Group Average	69.76	2.51	2.57	3.83	10.27
Group Average G				6.40	
DCF				**10.23**	

Electric Company Barometer Group 52-week Average Dividend Yield Calculation						
	High	Low	Average (Pa)	Latest Indicated Dividend (Do)	Average Dividend Yield (Do/Pa)	DCF
	($)	($)	($)	($)	(%)	(%)
Alliant Energy Corp	66.54	47.23	56.89	2.03	3.57	10.07
Ameren Corp	104.10	69.39	86.75	2.84	3.27	9.97
American Electric Power	110.48	79.16	94.82	3.72	3.92	10.42
Avista Corp	43.09	33.00	38.05	1.96	5.15	10.81
CenterPoint Energy	37.70	25.41	31.56	0.88	2.79	10.12
CMS Energy Corp	76.45	56.61	66.53	2.17	3.26	10.25
Consolidated Edison	114.87	87.28	101.08	3.40	3.36	9.20
Dominion Energy	61.97	46.62	54.30	2.67	4.92	8.42
DTE Energy Company	140.39	103.06	121.73	4.36	3.58	11.57
Duke Energy Company	125.27	92.75	109.01	4.18	3.83	10.04
Edison International	88.77	49.06	68.92	3.31	4.80	12.38
Entergy Corp.	88.38	50.19	69.29	2.40	3.46	12.65
Evergy Inc	70.30	49.55	59.93	2.67	4.46	10.76
Eversource Energy	69.01	54.54	61.78	3.01	4.87	10.45
Exelon Corporation	48.11	34.01	41.06	1.60	3.90	9.94
FirstEnergy Corp	44.97	36.81	40.89	1.78	4.35	10.52
IDACORP, Inc..	120.84	88.70	104.77	3.44	3.28	10.89
MGE Energy, Inc.	109.22	72.27	90.75	1.80	1.98	8.98
NextEra Energy, Inc.	86.10	61.31	73.71	2.27	3.08	10.88
NorthWestern Corp	59.52	47.48	53.50	2.64	4.93	10.45
OGE Energy Corp	46.91	32.37	39.64	1.69	4.26	10.44
Otter Tail Corp	100.84	71.66	86.25	2.10	2.43	8.78
PPL Corporation	36.64	25.93	31.29	1.09	3.48	10.66
TXNM Energy Inc.	55.50	35.35	45.43	1.63	3.59	8.86
Pinnacle West Capital Corp	96.50	70.72	83.61	3.58	4.28	9.18
Portland General Electric Co.	49.85	40.05	44.95	2.00	4.45	9.42
Public Service Enterprise Group	95.22	64.03	79.63	2.52	3.16	9.75
Southern Company	94.45	67.53	80.99	2.88	3.56	10.00
Xcel Energy Inc.	73.38	51.97	62.68	2.28	3.64	10.62
Group Average	79.84	56.69	68.27	2.51	3.78	10.22
Group Average G					6.40	
DCF					**10.18**	
		Average of Current and 52-Week			**10.20**	

Multiple sources of the Barometer companies' projected 5-year Earnings Per Share are used to calculate the Group Average Dividend Growth Estimate.

Development of a Representative Dividend Growth Rate
for the Barometer Group of Electric Companies

		5 Year Forecast				
	Value Line DPS (%)	Value Line EPS (%)	Zack's EPS (%)	S&P EPS (%)	Average Earnings Growth (%)	Growth Estimate (%)
Alliant Energy Corp	6.00	6.00	6.70	6.81	6.50	6.50
Ameren Corp	6.50	6.50	6.70	6.88	6.69	6.69
American Electric Power	5.50	6.50	6.30	6.69	6.50	6.50
Avista Corp	4.00	5.00	6.10	5.88	5.66	5.66
CenterPoint Energy	6.00	6.50	7.50	7.98	7.33	7.33
CMS Energy Corp	5.00	6.00	7.70	7.27	6.99	6.99
Consolidated Edison	4.00	6.00	5.60	5.91	5.84	5.84
Dominion Energy	0.50	3.50	13.60	13.49	10.20	3.50
DTE Energy Company	4.50	8.50	7.60	7.87	7.99	7.99
Duke Energy Company	3.50	6.00	6.30	6.32	6.21	6.21
Edison International	6.00	6.50	8.50	7.74	7.58	7.58
Entergy Corp.	5.50	3.00	9.50	8.88	7.13	9.19
Evergy Inc	7.00	7.50	5.70	5.72	6.31	6.31
Eversource Energy	6.00	5.50	5.70	5.54	5.58	5.58
Exelon Corporation	NA	NA	6.00	6.09	6.05	6.05
FirstEnergy Corp	5.50	5.50	6.90	6.11	6.17	6.17
IDACORP, Inc..	5.50	6.00	8.50	8.31	7.60	7.60
MGE Energy, Inc.	6.50	7.00	NA	NA	7.00	7.00
NextEra Energy, Inc.	9.50	8.50	7.80	7.11	7.80	7.80
NorthWestern Corp	1.50	4.50	6.10	5.94	5.51	5.51
OGE Energy Corp	3.00	6.50	6.10	5.92	6.17	6.17
Otter Tail Corp	7.00	4.50	NA	8.20	6.35	6.35
PPL Corporation	-0.50	7.50	6.80	7.22	7.17	7.17
TXNM Energy Inc.	5.50	4.00	3.00	6.55	4.52	5.28
Pinnacle West Capital Corp	1.50	4.00	2.10	5.80	3.97	4.90
Portland General Electric Co.	5.50	5.50	3.40	6.01	4.97	4.97
Public Service Enterprise Group	6.00	6.00	7.20	6.56	6.59	6.59
Southern Company	3.50	6.50	6.50	6.33	6.44	6.44
Xcel Energy Inc.	6.00	6.50	6.90	7.56	6.99	6.99
Group Average	4.86	5.91	6.70	7.02	6.54	6.44
USE						**6.40**

Sources: Value Line, April 8, 2025 (www.valueline.com)
Zacks, April 8, 2025 (www.zacks.com)
Yahoo!, April 8, 2025 (http://finance.yahoo.com/)
S&P Capital IQ, April 8, 2025 (www.spglobal.com)
* NA signifies that a forecast was not available

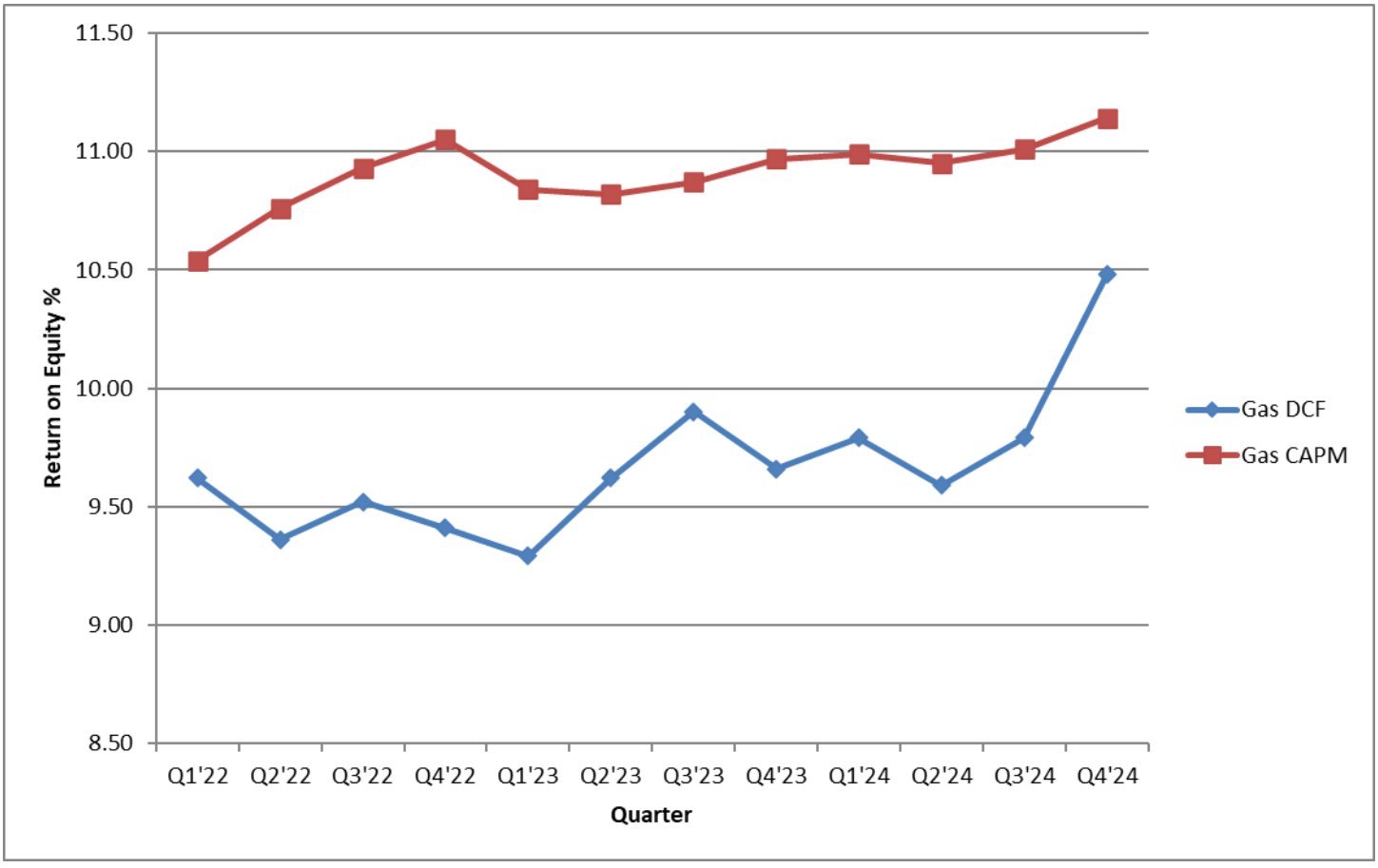
The market indicated common equity cost rate range consists of data used from the barometer groups and is based on a series of calculations to average the DCF methods.

Market Based Returns on Common Equity[1]	
April 7, 2025	
Gas Distribution Company Barometer Group	
	Cost Rates
	%
(1) Current DCF:	10.46
(2) 52-Week Average DCF:	10.51
(3) Overall DCF ((1) + (2)) / 2 :	10.48
(4) Market Indicated Common Equity Cost Rate Range:	8.92-12.05
@ 1 standard deviation around the mean.[2]	
(5) CAPM Check of DCF Reasonableness:	11.14
(6) Recent Commission Approved ROEs[3]:	*
*None within the last two years	
(7) Distribution System Improvement Charge (DSIC) Return[4]:	**10.15%**
[1] As calculated by the Bureau of Technical Utility Services	
[2] Standard Deviation of 16 DCF observations	
[3] Base rate case ROEs within last two years, fully litigated or stipulated for DSIC	
[4] Commission authorized Return on Equity (ROE) for DSIC purposes	
Any questions concerning DSIC should be directed to Rich Layton	
of the Bureau of Technical Utility Services at (717) 214-9117.	

Historic Gas Industry DCF and CAPM Average ROEs

Gas		
	DCF	CAPM
Q1'22	9.62	10.54
Q2'22	9.36	10.76
Q3'22	9.52	10.93
Q4'22	9.41	11.05
Q1'23	9.29	10.84
Q2'23	9.62	10.82
Q3'23	9.90	10.87
Q4'23	9.66	10.97
Q1'24	9.79	10.99
Q2'24	9.59	10.95
Q3'24	9.79	11.01
Q4'24	10.48	11.14

Graph of Historic Gas Industry DCF and CAPM Average ROEs



Barometer gas companies are used to calculate a current DCF in the first chart. The second chart demonstrates the companies' 52-week average DCF. A final average of the two calculations is also shown at the bottom.

Gas Company Barometer Group
Calculation of a Current Dividend Yield

	Closing Market Price (Po) 4/7/2025 ($)	Latest Indicated Dividend (Do) ($)	Ind. Div. Plus 1/2 Div. Growth Rate (D1) ($)	Current Dividend Yield(D1/Po) (%)	DCF (%)
Atmos Energy	145.06	3.48	3.60	2.48	9.39
Chesapeake Utilities Corporation	126.28	2.56	2.66	2.10	8.68
New Jersey Resources	46.94	1.80	1.85	3.93	10.23
NiSource Inc.	37.16	1.12	1.16	3.11	11.06
Northwest Natural Gas	40.06	1.96	1.96	4.90	11.40
ONE Gas, Inc.	71.91	2.68	2.71	3.77	8.35
Southwest Gas	66.91	2.48	2.55	3.81	13.56
Spire Inc.	73.73	3.14	3.20	4.34	10.70
Group Average	76.01	2.40	2.46	3.56	10.42
Group Average G				6.90	
DCF				**10.46**	

Gas Company Barometer Group
52-week Average Dividend Yield Calculation

	High ($)	Low ($)	Average (Pa) ($)	Latest Indicated Dividend (Do) ($)	Average Dividend Yield (Do/Pa) (%)	DCF (%)
Atmos Energy	157.62	110.97	134.30	3.48	2.59	9.50
Chesapeake Utilities Corporation	134.86	98.32	116.59	2.56	2.20	8.77
New Jersey Resources	51.95	40.62	46.29	1.80	3.89	10.19
NiSource Inc.	41.45	26.26	33.86	1.12	3.31	11.25
Northwest Natural Gas	44.25	34.82	39.54	1.96	4.96	11.46
ONE Gas, Inc.	78.89	58.31	68.60	2.68	3.91	8.48
Southwest Gas	80.29	64.31	72.30	2.48	3.43	13.18
Spire Inc.	79.81	57.27	68.54	3.14	4.58	10.94
Group Average	83.64	61.36	72.50	2.40	3.61	10.47
Group Average G					6.90	
DCF					**10.51**	
		Average of Current and 52-Week			**10.48**	

Multiple sources of the Barometer companies' projected 5-year Earnings Per Share are used to calculate the Group Average Dividend Growth Estimate.

Development of a Representative Dividend Growth Rate for the Barometer Group of Gas Companies						
	5 Yr Forecast					
	Value Line DPS (%)	Value Line EPS (%)	Zack's EPS (%)	S&P EPS (%)	Average Earnings Growth (%)	Growth Estimate (%)
Atmos Energy	7.00	6.00	7.20	7.52	6.91	6.91
Chesapeake Utilities Corporation	7.50	5.00	NA	8.15	6.58	6.58
New Jersey Resources	5.00	5.00	NA	7.60	6.30	6.30
NiSource Inc.	6.50	8.00	7.90	7.94	7.95	7.95
Northwest Natural Gas	0.50	6.50	NA	6.50	6.50	6.50
ONE Gas, Inc.	2.50	4.00	5.90	3.83	4.58	4.58
Southwest Gas	5.50	10.00	9.50	12.60	10.70	9.75
Spire Inc.	4.00	4.50	6.50	8.08	6.36	6.36
Group Average	4.81	6.13	7.40	7.78	6.98	6.86
USE						**6.90**
Sources:	Value Line, April 8, 2025 (www.valueline.com)					
	Zacks, April 8, 2025 (www.zacks.com)					
	Yahoo!, April 8, 2025 (http://finance.yahoo.com/)					
	S&P Capital IQ, April 8, 2025 (www.spglobal.com)					
	* NA signifies that a forecast was not available					

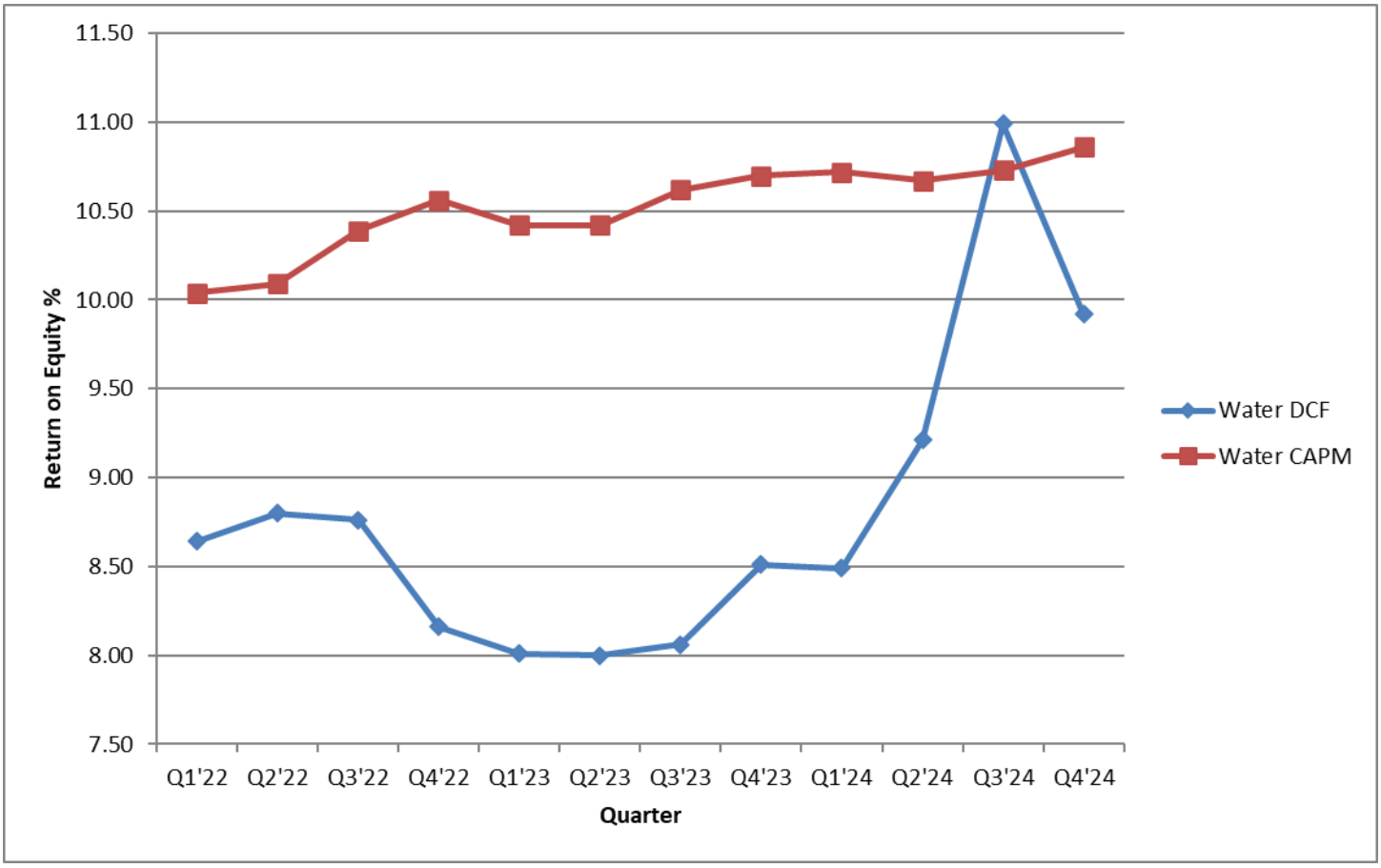
The market indicated common equity cost rate range consists of data used from the barometer groups and is based on a series of calculations to average the DCF methods.

Market Based Returns on Common Equity [1]	
April 7, 2025	
Water Company Barometer Group	
	Cost Rates %
(1) Current DCF	9.96
(2) 52-Week Average DCF	9.88
(3) Average DCF	9.92
(4) Market Indicated Common Equity Cost Rate Range @ 1 standard deviation around the mean.[2]	7.25-12.59
(5) CAPM Check of DCF Reasonableness	10.86
(6) Recent Commission Approved ROEs[3]:	
Columbia Water Company, R-2023-3040258	9.75
Pennsylvania-American water Company, R-2023-3043189	9.45
(7) Distribution System Improvement Charge (DSIC) Return[4]:	**9.75%**
[1] As calculated by the Bureau of Technical Utility Services	
[2] Standard Deviation of 12 DCF observations	
[3] ROEs from base rate cases within last two years, fully litigated or stipulated for DSIC purposes	
[4] Commission authorized Return on Equity (ROE) for DSIC purposes	
Any questions concerning DSIC should be directed to Rich Layton	
of the Bureau of Technical Utility Services at (717) 214-9117.	

Historic Water Industry DCF and CAPM Average ROEs

Water		
	DCF	CAPM
Q1'22	8.64	10.04
Q2'22	8.80	10.09
Q3'22	8.76	10.39
Q4'22	8.16	10.56
Q1'23	8.01	10.42
Q2'23	8.00	10.42
Q3'23	8.06	10.62
Q4'23	8.51	10.70
Q1'24	8.49	10.72
Q2'24	9.21	10.67
Q3'24	10.99	10.73
Q4'24	9.92	10.86

Chart of Historic Water Industry DCF and CAPM Average ROEs



Barometer water companies are used to calculate a current DCF in the first chart. The second chart demonstrates the companies' 52-week average DCF. A final average of the two calculations is also shown at the bottom.

Water Company Barometer Group
Calculation of a Current Dividend Yield

	Closing Market Price (Po) 4/7/2025	Latest Indicated Dividend (Do)	Ind. Div. Plus 1/2 Div. Growth Rate (D1)	Current Dividend Yield(D1/Po)	Growth	DCF
	($)	($)	($)	(%)	(%)	(%)
American States Water Company	75.41	1.86	1.93	2.57	3.52	6.08
American Water Works Co., Inc.	142.36	3.06	3.19	2.24	6.76	9.00
California Water Service Group	47.50	1.20	1.23	2.60	9.50	12.10
Essential Utilities, Inc.	38.32	1.30	1.35	3.53	6.70	10.23
Middlesex Water Company	61.62	1.36	1.39	2.26	11.65	13.92
SJW Group	51.28	1.68	1.72	3.35	5.17	8.52
Group Average	69.42	1.74	1.80	2.76	7.22	9.97
Group Average G				7.20		
DCF				**9.96**		

Water Company Barometer Group
52-week Average Dividend Yield Calculation

	High	Low	Average (Pa)	Latest Indicated Dividend (Do)	Average Dividend Yield (Do/Pa)	Growth	DCF
	($)	($)	($)	($)	(%)	(%)	(%)
American States Water Company	87.50	66.03	76.77	1.86	2.42	3.52	5.94
American Water Works Co., Inc.	155.50	113.34	134.42	3.06	2.28	6.76	9.03
California Water Service Group	56.25	41.64	48.95	1.20	2.45	9.50	11.95
Essential Utilities, Inc.	41.78	33.18	37.48	1.30	3.47	6.70	10.17
Middlesex Water Company	70.73	45.42	58.08	1.36	2.34	11.65	14.00
SJW Group	62.18	44.91	53.55	1.68	3.14	5.17	8.31
Group Average	78.99	57.42	68.21	1.74	2.68	7.22	9.90
Group Average G					7.20		
DCF					**9.88**		
		Average of Current and 52-Week			**9.92**		

Multiple sources of the Barometer companies' projected 5-year Earnings Per Share are used to calculate the Group Average Dividend Growth Estimate.

Development of a Representative Dividend Growth Rate
for the Barometer Group of Water Companies

	5 Yr Forecast					
					Average	
	Value Line	Value Line	Zacks	S&P	Earnings	Growth
	DPS	EPS	EPS	EPS	Growth	Estimate
	(%)	(%)	(%)	(%)	(%)	(%)
American States Water Company	8.00	7.00	1.80	1.75	3.52	3.52
American Water Works Co., Inc.	8.50	4.50	8.00	7.77	6.76	6.76
California Water Service Group	5.50	9.50	42.40	42.44	31.45	9.50
Essential Utilities, Inc.	8.00	7.00	6.60	6.51	6.70	6.70
Middlesex Water Company	5.00	7.00	14.00	13.96	11.65	11.65
SJW Group	4.50	6.50	4.50	4.52	5.17	5.17
Group Average	6.58	6.92	12.88	12.83	10.88	7.22
USE						**7.20**

Sources: Value Line, April 8, 2025 (www.valueline.com)
Zacks, April 8, 2025 (www.zacks.com)
Yahoo!, April 8, 2025 (http://finance.yahoo.com/)
S&P Capital IQ, April 8, 2025 (www.spglobal.com)
* NA signifies that a forecast was not available

EXHIBIT JBF-2

				Requested			Approved				
State	Company	Case identification	Service	Date	Rate Change ($000)	ROE (%)	Date	Rate Change ($000)	ROE (%)	Case Type	Decision Type
OR	Avista Corporation	D-UG-519	Natural Gas	11/1/2024	7,822	10.40	5/23/2025	4,195	9.50	Distribution	Settled
VA	Columbia Gas of Virginia, Incorporated	C-PUR-2024-00030	Natural Gas	4/29/2024	52,632	10.85	5/15/2025	40,700	9.75	Distribution	Settled
TX	Atmos Energy Corporation	D-OS-24-00018879(West Te	Natural Gas	10/25/2024	65,555	10.85	5/13/2025	30,200	9.80	Distribution	Settled
VA	Roanoke Gas Company	C-PUR-2024-00006	Natural Gas	2/2/2024	4,188	10.35	4/10/2025	4,080	9.90	Distribution	Settled
AZ	Southwest Gas Corporation	D-G-01551A-23-0341	Natural Gas	2/2/2024	95,910	9.65	3/27/2025	80,242	9.84	Distribution	Settled
NY	Orange and Rockland Utilities, Inc.	C-24-G-0061	Natural Gas	1/26/2024	17,480	10.25	3/20/2025	3,568	9.75	Distribution	Settled
WA	Cascade Natural Gas Corporation	D-UG-240008	Natural Gas	3/29/2024	55,499	10.50	2/24/2025	40,613	9.50	Distribution	Settled
MN	Northern States Power Company	D-G-002/GR-23-413	Natural Gas	11/1/2023	81,283	10.20	2/13/2025	68,880	9.60	Distribution	Settled
NC	Piedmont Natural Gas Company, Inc.	D-G-9 Sub 837	Natural Gas	4/1/2024	195,766	10.50	1/7/2025	141,462	9.80	Distribution	Settled
KY	Columbia Gas of Kentucky, Incorporated	C-2024-00092	Natural Gas	5/16/2024	23,773	10.80	12/30/2024	14,293	9.75	Distribution	Settled
NY	National Fuel Gas Distribution Corporation	C-23-G-0627	Natural Gas	10/31/2023	88,560	9.80	12/19/2024	57,291	9.70	Distribution	Settled
NJ	New Jersey Natural Gas Company	D-GR24010071	Natural Gas	1/31/2024	219,862	10.42	11/21/2024	157,000	9.60	Distribution	Settled
NJ	Elizabethtown Gas Company	D-GR24020158	Natural Gas	2/29/2024	70,254	10.75	11/21/2024	38,000	9.60	Distribution	Settled
AR	Summit Utilities Arkansas, Inc.	D-23-079-U	Natural Gas	1/25/2024	101,194	11.00	11/21/2024	87,684	9.85	Distribution	Settled
TX	Texas Gas Service Company, Inc.	D-OS-24-00017471(Central-	Natural Gas	6/3/2024	25,573	10.25	11/20/2024	19,300	9.70	Distribution	Settled
ND	MDU Resources Group, Inc.	C-PU-23-341	Natural Gas	11/1/2023	11,635	10.50	11/7/2024	9,444	9.90	Distribution	Settled
ND	Northern States Power Company	C-PU-23-367	Natural Gas	12/29/2023	8,463	10.20	11/7/2024	7,348	9.90	Distribution	Settled
IN	Ohio Valley Gas Inc	Ca-46011	Natural Gas	2/7/2024	12,062	11.00	11/6/2024	11,059	10.00	Distribution	Settled
OR	Northwest Natural Gas Company	D-UG-490	Natural Gas	12/29/2023	152,345	10.10	10/25/2024	95,000	9.40	Distribution	Settled
NJ	Public Service Electric and Gas Company	D-GR23120925	Natural Gas	12/29/2023	409,438	10.40	10/9/2024	270,800	9.60	Distribution	Settled
AR	Black Hills Energy Arkansas, Inc.	D-23-074-U	Natural Gas	12/4/2023	39,108	10.50	10/1/2024	29,076	9.85	Distribution	Settled
MI	Michigan Gas Utilities Corporation	C-U-21540	Natural Gas	3/1/2024	11,300	10.25	9/26/2024	7,000	9.86	Distribution	Settled
IA	Interstate Power and Light Company	D-RPU-2023-0002 (gas)	Natural Gas	10/12/2023	13,934	10.00	9/17/2024	10,000	9.65	Distribution	Settled
NY	The Brooklyn Union Gas Company	C-23-G-0225	Natural Gas	4/28/2023	466,486	9.80	8/15/2024	443,984	9.35	Distribution	Settled
NY	KeySpan Gas East Corporation	C-23-G-0226	Natural Gas	4/28/2023	277,257	9.80	8/15/2024	246,468	9.35	Distribution	Settled
IN	Northern Indiana Public Service Company, LI	Ca-45967	Natural Gas	10/25/2023	161,897	10.70	7/31/2024	120,948	9.75	Distribution	Settled
NM	New Mexico Gas Company, Inc.	C-23-00255-UT	Natural Gas	9/14/2023	48,430	10.50	7/25/2024	30,000	9.38	Distribution	Settled
MI	Consumers Energy Company	C-U-21490	Natural Gas	12/15/2023	136,034	10.25	7/23/2024	35,000	9.90	Distribution	Settled
TX	CenterPoint Energy Resources Corp.	D-OSS-23-00015513 (Texas	Natural Gas	10/30/2023	38,844	10.50	6/26/2024	5,000	9.80	Distribution	Settled
OH	Northeast Ohio Natural Gas Corp.	C-23-0154-GA-AIR	Natural Gas	3/31/2023	5,981	10.90	4/17/2024	2,395	9.75	Distribution	Settled
NV	Southwest Gas Corporation	D-23-09012 (Northern)	Natural Gas	9/11/2023	10,473	10.00	4/8/2024	8,700	9.50	Distribution	Settled
NV	Southwest Gas Corporation	D-23-09012 (Southern)	Natural Gas	9/11/2023	63,504	10.00	4/8/2024	50,400	9.50	Distribution	Settled
CO	Black Hills Colorado Gas, Inc.	D-23AL-0231G	Natural Gas	5/8/2023	26,105	10.49	3/24/2024	20,171	9.30	Distribution	Settled
TX	Texas Gas Service Company, Inc.	D-OSS-23-00014399(Rio Gr	Natural Gas	6/30/2023	9,813	10.25	1/31/2024	5,875	9.70	Distribution	Settled
WY	Black Hills Wyoming Gas, LLC	D-30026-78-GR-23	Natural Gas	5/18/2023	20,498	10.49	1/17/2024	15,143	9.85	Distribution	Settled
WA	Puget Sound Energy, Inc.	D-UG-240005	Natural Gas	2/15/2024	224,794	10.50	1/15/2025	130,907	9.90	Distribution	Fully Litigated
WA	Avista Corporation	D-UG-240007	Natural Gas	1/18/2024	20,819	10.40	12/20/2024	18,200	9.80	Distribution	Fully Litigated
WI	Wisconsin Public Service Corporation	D-6690-UR-128 (Gas)	Natural Gas	4/12/2024	42,881	10.00	12/19/2024	28,401	9.80	Distribution	Fully Litigated
WI	Wisconsin Electric Power Company	D-5-UR-111 (Gas)	Natural Gas	4/12/2024	88,479	10.00	12/19/2024	71,103	9.80	Distribution	Fully Litigated
WI	Wisconsin Gas LLC	D-5-UR-111	Natural Gas	4/12/2024	98,269	10.00	12/19/2024	58,009	9.80	Distribution	Fully Litigated
CT	Connecticut Natural Gas Corporation	D-23-11-02 (CNG)	Natural Gas	11/3/2023	19,703	10.20	11/18/2024	-24,610	9.15	Distribution	Fully Litigated
CT	The Southern Connecticut Gas Company	D-23-11-02 (SCG)	Natural Gas	11/3/2023	43,239	10.20	11/18/2024	-10,716	9.15	Distribution	Fully Litigated
MI	DTE Gas Company	C-U-21291	Natural Gas	1/8/2024	262,407	10.25	11/7/2024	113,788	9.80	Distribution	Fully Litigated
IL	Liberty Utilities (Midstates Natural Gas) Corp	D-24-0043	Natural Gas	12/20/2023	4,148	10.80	10/31/2024	3,174	9.90	Distribution	Fully Litigated
CO	Public Service Company of Colorado	D-24AL-0049G	Natural Gas	1/29/2024	169,571	10.10	10/25/2024	130,759	9.35	Distribution	Fully Litigated
CA	Southern California Gas Company	A-22-04-011 (Phase 2)	Natural Gas	1/16/2024	NA	10.50	10/17/2024	-28,900	10.08	Distribution	Fully Litigated
NV	Sierra Pacific Power Company	D-24-02027	Natural Gas	2/23/2024	12,201	10.34	9/18/2024	8,363	9.45	Distribution	Fully Litigated
NY	Central Hudson Gas & Electric Corporation	C-23-G-0419	Natural Gas	7/31/2023	42,002	9.80	7/18/2024	27,307	9.50	Distribution	Fully Litigated
MA	Fitchburg Gas and Electric Light Company, In	DPU 23-81	Natural Gas	8/17/2023	11,278	10.75	6/28/2024	10,208	9.40	Distribution	Fully Litigated
AK	ENSTAR Natural Gas Company	D-U-22-081	Natural Gas	8/1/2022	5,041	12.95	4/8/2024	1,345	11.88	Distribution	Fully Litigated
MD	Columbia Gas of Maryland, Incorporated	C-9754	Natural Gas	9/24/2024	10,747	11.05	4/22/2025	7,820	9.80	Distribution	
VA	Columbia Gas of Virginia, Incorporated	C-PUR-2024-00103 (SAVE)	Natural Gas	8/15/2024	-3,778	9.70	11/19/2024	-3,778	9.70	Limited-Issue Rider	Fully Litigated
VA	Roanoke Gas Company	C-PUR-2024-00093 (SAVE)	Natural Gas	6/28/2024	1,309	10.35	9/24/2024	1,171	9.44	Limited-Issue Rider	Fully Litigated
VA	Roanoke Gas Company	C-PUR-2024-00098 (Rider F	Natural Gas	5/30/2024	122	11.35	9/4/2024	94	10.44	Limited-Issue Rider	Fully Litigated
VA	Washington Gas Light Company	C-PUR-2023-00220 (Rider F	Natural Gas	12/4/2023	1,352	10.65	5/30/2024	NA	9.65	Limited-Issue Rider	Fully Litigated

Source: S&P Capital IQ (dated 6-25-2025)

EXHIBIT JBF-3

DIRECT TESTIMONY WORKPAPERS**

JBF WP-1 Valley Energy Exhibit HSG-1**

JBF WP-2 Survey of Gas ROE**

The above referenced workpapers, JBF WP-1, and JBF WP-2 will be served electronically in excel format only, simultaneous to service of OSBA's Direct Testimony ONLY

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	**Docket No. R-2025-3054393**
v.	:	
	:	
Valley Energy, Inc.	:	

VERIFICATION

I, Justin B. Farr, hereby state that the facts set forth in my Direct Testimony, labelled OSBA Statement No. 1, and Exhibit JBF-1, Exhibit JBF-2, and Exhibit JBF-3, are true and correct to the best of my knowledge, information, and belief, and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements made herein are subject to the penalties of 18 Pa. C.S. § 4904 (relating to unsworn falsification to authorities).

Date: July 14, 2025

Justin B. Farr

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	**Docket No. R-2025-3054393**
v.	:	
	:	
Valley Energy, Inc.	:	

CERTIFICATE OF SERVICE

I hereby certify that true and correct copies of the foregoing have been served via email (*unless otherwise noted below*) upon the following persons, in accordance with the requirements of 52 Pa. Code § 1.54 (relating to service by a participant).

The Honorable Mary D. Long
Administrative Law Judge
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301 Fifth Avenue, Suite 220
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vgeddis@mcneeslaw.com

Date: July 15, 2025

/s/ Rebecca Lyttle
Rebecca Lyttle
Assistant Small Business Advocate
Attorney ID No. 201399

COMMONWEALTH OF PENNSYLVANIA

August 28, 2025

The Honorable Mary D. Long
Administrative Law Judge
Pennsylvania Public Utility Commission
Piatt Place
301 Fifth Avenue, Suite 220
Pittsburgh, PA 15222

Re: Pennsylvania Public Utility Commission v. Valley Energy, Inc. / Docket No. R-2025-3054393

Dear Judge Long:

Enclosed please find the Surrebuttal Testimony and Exhibit of Justin B. Farr, labelled OSBA Statement No.1-SR, with associated Exhibit JBF-1SR, on behalf of the Office of Small Business Advocate ("OSBA"), in the above-referenced proceeding.

As evidenced by the enclosed Certificate of Service, all known parties will be served, as indicated.

If you have any questions, please do not hesitate to contact me.

Sincerely,

/s/ Rebecca Lyttle

Rebecca Lyttle
Assistant Small Business Advocate
Attorney ID No. 201399

Enclosures
cc: PA PUC Secretary Matthew L. Homsher (Cover Letter & Certificate of Service only)
Kevin Higgins / Rebecca Forbes / Justin Farr
Joseph Kubas
Parties of Record

OSBA Statement No. 1-SR

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	**:**	
	:	**Docket No. R-2025-3054393**
v.	**:**	
	:	
Valley Energy, Inc.	**:**	

Surrebuttal Testimony and Exhibit

of

Justin B. Farr

on behalf of

Pennsylvania Office of Small Business Advocate

Topics:

Revenue Requirement Adjustments

Date Served: August 28, 2025

Date Submitted for the Record: _____

SURREBUTTAL TESTIMONY OF JUSTIN B. FARR

INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Justin B. Farr. My business address is 111 East Broadway, Suite 1200, Salt Lake City, Utah, 84111.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am a Director in the firm of Energy Strategies, LLC. Energy Strategies is a private consulting firm specializing in economic and policy analysis applicable to energy production, transportation, and consumption.

Q. ARE YOU THE SAME JUSTIN B. FARR WHO PREFILED DIRECT TESTIMONY IN THIS DOCKET ON BEHALF OF THE PENNSYLVANIA OFFICE OF SMALL BUSINESS ADVOCATE ("OSBA")?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR SURREBUTTAL TESTIMONY?

A. My surrebuttal testimony responds to the rebuttal testimony of Valley Energy, Inc ("Valley" or "the Company) witness Dylan W. D'Ascendis, and Pennsylvania Office of Consumer Advocate ("OCA") witness Christopher C. Walters regarding my use of a 10% proxy return on equity ("ROE") in my revenue requirement calculations.

I respond to Valley witness Edward E. Rogers regarding the Performance Factor Adjustment and Size Adjustment.

I also respond to Valley witness Howard S. Gorman regarding my Uncollectibles expense adjustment.

Q. WHAT CONCLUSIONS DO YOU OFFER IN YOUR SURREBUTTAL TESTIMONY?

A. I offer the following conclusions:

1) I explain my use of a proxy ROE in my direct revenue requirement calculations and provide the results of my revenue requirement calculations using the costs of capital recommended by the Bureau of Investigation & Enforcement ("I&E") and OCA.
2) I continue to recommend eliminating the performance factor entirely and lowering or removing the size factor adjustment.
3) I continue to recommend a decrease in Uncollectables expense of $2,628 reflected in Table JBF-1 of my direct testimony.

REVENUE REQUIREMENT ADJUSTMENTS

Proxy Return on Equity Adjustment

Q. PLEASE DESCRIBE YOUR PROXY ROE ADJUSTMENT.

A. I assumed the 10.15% ROE authorized by the Commission for the Distribution System Improvement Charge ("DSIC") for natural gas utilities included in the most recent Report on the Quarterly Earnings of Jurisdictional Utilities for the year ended December 31, 2024 produced by the Bureau of Technical Utility Services ("TUS").[1]

[1] Direct Testimony of Justin B. Farr (OSBA Statement No. 1) p. 11.

Q. DO ANY PARTIES TAKE ISSUE WITH YOUR USE OF THIS PLACEHOLDER ROE?

A. Yes. Citizens' witness Dylan W. D'Ascendis testifies that while the range of ROEs calculated by the TUS in its quarterly report is generally consistent with both his initial and updated model results – and while the upper end of the TUS ranges for gas and electric utilities aligns with his Company-specific recommendation – the TUS ranges do not account for the performance of Valley's management. As a result, he argues the TUS analysis provides an incomplete basis for determining the Companies' appropriate ROE.[2]

OCA witness Christopher C. Walters states that he disagrees with my use of a 10.15% DSIC ROE from the Commission's Quarterly Earnings Report as a proxy ROE for the Company. He claims that the Commission has expressly and repeatedly rejected the use of its DSIC ROE for purposes of establishing the cost of equity in base rate proceedings and cites one case, a Pike County Light and Power rate case.[3] Mr. Walters concludes that because my proxy ROE is not grounded in a proper cost of equity analysis and is inconsistent with Commission precedent, the portion attributed to ROE of my proposed downward adjustment to the Company's revenue requirement should be rejected.[4]

Q. HOW DO YOU RESPOND TO THESE CONCERNS?

A. To clarify, I am not suggesting that the DSIC ROE be adopted in this proceeding in the absence of a detailed ROE analysis. My use of the proxy 10.15% DSIC ROE

[2] Rebuttal Testimony of Dylan W. D'Ascendis (Joint Statement No. 2R) p. 3.
[3] Rebuttal Testimony of Christopher C. Walters (OCA Statement 2R) pp. 11-13.
[4] *Id.* p.13.

is not intended to replace the Commission's consideration of traditional cost of capital analyses offered by other parties in this proceeding.

Q. HAVE YOU ANALYZED THE IMPACT OF OTHER PARTIES' COST OF CAPITAL RECOMMENDATIONS ON YOUR REVENUE REQUIREMENT CALCULATIONS?

A. Yes. In Table JBF-1SR I provide a summary of the total revenue increases that would result from utilizing I&E's and OCA's recommended return on equity in my revenue requirement calculations.

Table JBF-1SR
OSBA Revenue Increase with OCA and I&E ROE Recommendations

	Low	Mid	High
Source of ROE Assumption	OCA	OSBA	I&E
ROE Rate Assumption	9.50%	10.15%	10.51%
Total Revenue Increase*	$1,227,958	$1,339,159	$1,398,235
Difference from OSBA Direct	-$111,201	$0	$59,075

*Assumes adjustments made in OSBA Direct Testimony

For comparison purposes, Table JBF-2SR summarizes the total revenue increases that I recommended in my direct testimony, as well as those recommended by I&E, OCA, and Valley.

Table JBF-2SR
Comparison of Proposed Revenue Increases

	Revenue Increase	Difference from Valley
Valley Application	$1,626,099	$0
OSBA Direct Testimony	$1,339,159	-$286,940
I&E Direct Testimony	$1,212,076	-$414,023
OCA Direct Testimony	$963,630	-$662,469

Performance Factor Adjustment and Size Adjustment

Q. PLEASE DESCRIBE YOUR PERFORMANCE FACTOR ADJUSTMENT AND SIZE ADJUSTMENT PROPOSALS.

A. I recommend eliminating the performance factor entirely and lowering or removing the size factor adjustment.[5]

Q. HOW DID VALLEY RESPOND TO YOUR PERFORMANCE FACTOR ADJUSTMENT?

A. Valley witness Edward E. Rogers states that Valley is committed to exceeding performance standards, not merely meeting them.[6] He states that a performance adjustment mechanism is available under Pennsylvania statute, and he believes Valley has earned it based on the Company's achievements and initiatives which he outlined in his Direct Testimony.[7]

Q. HOW DID VALEY RESPOND TO YOUR SIZE ADJUSTMENT PROPOSAL?

A. Mr. Roger's referred to his Direct Testimony that explains the risk of losing one or more of the largest customers who have access to potential alternatives to natural gas service. He additionally states that the Commission has previously approved a size adjustment for small utilities, including Valley.[8] He claims that when the Company is making investment decisions and planning for future financial activities, including the timing of rate cases, it is important for them to be able to use consistent assumptions and that large changes in regulatory treatment on the

[5] Direct Testimony of Justin B. Farr (OSBA Statement No. 1) p. 9.
[6] Rebuttal Testimony of Edward E. Rogers (Valley Statement No. 4R) p. 3.
[7] *Id.* p. 4.
[8] *Id.*

size adjustment would complicate their planning and create additional financial risk for Valley.[9]

Q. HOW DO YOU RESPOND TO VALLEY'S CONCERN THAT LARGE CUSTOMERS HAVE ACCESS TO POTENTIAL ALTERNATIVES TO NATURAL GAS SERVICE?

A. The decision of large customers to pursue alternative energy sources is primarily influenced by cost considerations. As Valley's prices increase, so does the likelihood that customers with the flexibility to switch will do so. Implementing the size adjustment will raise costs further, thereby exacerbating the very risk that Valley asserts the adjustment is intended to mitigate.

Q. HOW DO YOU RESPOND TO VALLEY'S POSITION THAT IT IS VERY IMPORTANT FOR THE COMPANY TO BE ABLE TO USE CONSISTENT ASSUMPTIONS AND THAT LARGE CHANGES IN REGULATORY TREATMENT ON THE SIZE ADJUSTMENT WOULD COMPLICATE PLANNING AND CREATE ADDITIONAL RISK FOR THE COMPANY?

A. Consistency cannot be the justification for perpetuating adjustments that are unwarranted. Valley should not receive upward adjustments simply for meeting obligations that every regulated utility is required to meet. Nor should it benefit from adjustments intended to shield it from hypothetical or speculative risks. Valley already operates under a framework that provides consistency and certainty, as a regulated utility, the Company is guaranteed a rate of return. That guarantee offers far greater consistency and certainty than what is available to nearly all other

[9] *Id.* p.6.

businesses subject to competitive market forces. Extending additional adjustments in the name of consistency would only reward Valley beyond what is reasonable or necessary.

Q. DID I&E AND OCA MAKE PROPOSALS RELATED TO THE PERFORMANCE FACTOR ADJUSTMENT AND THE SIZE ADJUSTMENT?

A. Yes. Both I&E and OCA witnesses recommended eliminating the performance factor adjustment and the size adjustment.

Uncollectibles Expense

Q. PLEASE DESCRIBE YOUR UNCOLLECTIBLES EXPENSE ADJUSTMENT.

A. In my direct testimony, Table JBF-1 shows a decrease in Uncollectibles expense of $2,628.[10]

Q. HOW DID VALLEY RESPOND TO YOUR UNCOLLECTIBLES EXPENSE ADJUSTMENT PROPOSAL?

A. Valley Witness Howard S. Gorman states that I include this decrease and offer no support for this proposed change, and that it should be rejected by the Commission.[11]

Q. HOW DO YOU RESPOND TO MR. GORMAN'S CLAIM THAT YOU PROVIDE NO SUPPORT FOR THIS PROPOSED CHANGE AND IT SHOULD BE REJECTED BY THE COMMISSION?

[10] Direct Testimony of Justin B. Farr (OSBA Statement No. 1) p. 4.
[11] Rebuttal Testimony of Howard S. Gorman (Valley Statement No. 1R) p. 10.

A. Valley Energy Exhibit HSG-1, worksheet C1-6 includes an Uncollectibles expense amount of $14,892. This figure is calculated by applying a rate of 0.924% to the projected increase in revenue required to achieve the requested return in FPFTY 2026. In my analysis, I used the exact same formula Valley applied: 0.924% multiplied by the revenue increase required, based on the adjustments I recommend. Using this method results in an Uncollectibles expense of $12,264, $2,628 less than the Company's request.

If the Commission ultimately disagrees with Valley's assumption of a 0.924% Uncollectibles rate, then the entire $14,892 proposed by Valley should be rejected or at least adjusted based upon the Commission's determination of a proper Uncollectibles rate assumption.

Q. DOES THIS CONCLUDE YOUR SURREBUTTAL TESTIMONY?

A. Yes, it does.

EXHIBIT JBF-1SR

SURREBUTTAL TESTIMONY WORKPAPERS**

JBF WP-1SR Valley HSG-1 with OSBA Adj and I&E ROE**

JBF WP-2SR Valley HSG-1 with OSBA Adj and OCA ROE**

The above referenced workpapers will be served electronically in excel format ONLY, simultaneous to service of OSBA's Surrebuttal Testimony ONLY

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	**Docket No. R-2025-3054393**
v.	:	
	:	
Valley Energy, Inc.	:	

VERIFICATION

I, Justin B. Farr, hereby state that the facts set forth in my Surrebuttal Testimony and Exhibit, labelled OSBA Statement No. 1-SR, with associated Exhibit JBF-1SR, are true and correct to the best of my knowledge, information, and belief, and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements made herein are subject to the penalties of 18 Pa. C.S. § 4904 (relating to unsworn falsification to authorities).

Date: August 27, 2025

Justin B. Farr

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	**Docket No. R-2025-3054393**
v.	:	
	:	
Valley Energy, Inc.	:	

CERTIFICATE OF SERVICE

I hereby certify that true and correct copies of the foregoing have been served via email (*unless otherwise noted below*) upon the following persons, in accordance with the requirements of 52 Pa. Code § 1.54 (relating to service by a participant).

The Honorable Mary D. Long
Administrative Law Judge
Pennsylvania Public Utility Commission
Piatt Place
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Pittsburgh, PA 15222
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Date: August 28, 2025

/s/ Rebecca Lyttle
Rebecca Lyttle
Assistant Small Business Advocate
Attorney ID No. 201399

OSBA EXHIBIT NO. 1

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	**Docket No. R-2025-3054392**
v.	:	
	:	
Wellsboro Electric Company	:	

OFFICE OF SMALL BUSINESS ADVOCATE'S
ADMITTED
TESTIMONY AND EXHIBITS

The Office of Small Business Advocate ("OSBA") admitted the enclosed testimony and exhibits, as evidence into the evidentiary record, as OSBA EXHIBIT NO. 1, at the Evidentiary Hearing, held on September 4, 2025, in the above-captioned proceeding:

- Direct Testimony and Exhibits of Justin B. Farr, labelled OSBA Statement No.1, with Exhibit JBF-1, Exhibit JBF-2, and Exhibit JBF-3, with signed Verification of Justin B. Farr.
- Rebuttal Testimony of Justin B. Farr, labelled OSBA Statement No.1-R, with signed Verification of Justin B. Farr.
- Surrebuttal Testimony and Exhibit of Justin B. Farr, labelled OSBA Statement No.1-SR, with associated Exhibit JBF-1SR, with signed Verification of Justin B. Farr.

Date: September 4, 2025

COMMONWEALTH OF PENNSYLVANIA

July 15, 2025

The Honorable Mary D. Long
Administrative Law Judge
Pennsylvania Public Utility Commission
Piatt Place
301 Fifth Avenue, Suite 220
Pittsburgh, PA 15222

Re: Pennsylvania Public Utility Commission v. Wellsboro Electric Company / Docket No. R-2025-3054392

Dear Judge Long:

Enclosed please find the Direct Testimony and Exhibits of Justin B. Farr, labelled OSBA Statement No.1, on behalf of the Office of Small Business Advocate ("OSBA"), in the above-referenced proceeding.

As evidenced by the enclosed Certificate of Service, all known parties will be served, as indicated.

If you have any questions, please do not hesitate to contact me.

Sincerely,

/s/ Rebecca Lyttle

Rebecca Lyttle
Assistant Small Business Advocate
Attorney ID No. 201399

Enclosures
cc: PA PUC Secretary Matthew L. Homsher (Cover Letter & Certificate of Service only)
Kevin Higgins / Rebecca Forbes / Justin Farr
Joseph Kubas
Parties of Record

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	**:**	
	:	**Docket No. R-2025-3054392**
v.	**:**	
	:	
Wellsboro Electric Company	**:**	

Direct Testimony & Exhibits

of

Justin B. Farr

on behalf of

Pennsylvania Office of Small Business Advocate

Topics:

Revenue Requirement Adjustments
Cost of Service
Revenue Allocation

Date Served: July 15, 2025

Date Submitted for the Record: _____

DIRECT TESTIMONY OF JUSTIN B. FARR

Section I - Introduction

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Justin B. Farr. My business address is 111 East Broadway, Suite 1200, Salt Lake City, Utah, 84111.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am a Director in the firm of Energy Strategies, LLC. Energy Strategies is a private consulting firm specializing in economic and policy analysis applicable to energy production, transportation, and consumption.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?

A. My testimony is being sponsored by the Pennsylvania Office of Small Business Advocate ("OSBA").

Q. PLEASE DESCRIBE YOUR PROFESSIONAL EXPERIENCE AND QUALIFICATIONS.

A. My academic background includes a B.S. in economics and an M.B.A. from the University of Utah. After completing my undergraduate degree and while I was completing courses for my master's degree, I worked in the Utah Governor's Office as an economist focused on revenue forecasting and tax policy. I joined Energy Strategies in 2005, where I assist private and public sector clients in the areas of energy-related economic and policy analysis, including evaluation of electric and gas utility rate matters.

From 2013 to 2017 and again from 2020 to early 2022, I worked at PacifiCorp, a six-state electric utility that operates in Utah, Wyoming, Idaho, Oregon, Washington, and California. My roles at PacifiCorp included Manager of Economic & Financial Analysis where I led teams of engineers and plant managers in developing economic solutions for optimizing existing thermal and renewable infrastructure investment, and Assistant Manager of Regulation where I focused on the company's internal 10-year plan. Between 2017 and 2019, I served as Vice President of Financial Planning at Magnum Development where I supported the commercial development of the company's underground salt dome assets. My qualifications are attached in the Appendix to this testimony.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION?

A. Yes. I testified in a proceeding concerning the Second DER Management Plan filed by PPL Electric Utilities Corp, Docket No. P-2024-3049223.

Q. HAVE YOU TESTIFIED BEFORE UTILITY REGULATORY COMMISSIONS IN OTHER STATES?

A. Yes. I have provided testimony before the Utah Public Service Commission and the Indiana Utility Regulatory Commission.

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY IN THIS PROCEEDING?

A. My testimony addresses recommended revenue requirement adjustments. The absence of comment on my part regarding a particular issue or revenue requirement item does not signify support for (or opposition to) the Company's filing with respect to that issue.

Q. ARE YOU MAKING A RECOMMENDATION FOR A SPECIFIC TOTAL REVENUE REQUIREMENT IN THIS CASE?

A. No. My revenue requirement adjustment recommendations address a limited number of issues. Therefore, I am not offering a recommendation for a specific total revenue requirement.

Q. PLEASE SUMMARIZE YOUR PRIMARY CONCLUSIONS AND RECOMMENDATIONS.

A. I offer the following recommendations and conclusions:

1) I recommend certain adjustments that will have the effect of reducing revenue requirement by $386,239 relative to the $2.9 million increase proposed by the Company. My recommended adjustments are outlined in Table JBF-1 presented later in my testimony. My recommended reduction does not account for or incorporate any other adjustments advanced by other parties that are not specifically addressed in my testimony.

2) I conclude that the cost of service study aligns with the principles of cost causation and that Citizens' proposed revenue allocation falls within the range of reasonableness.

Section II - Revenue Requirement Adjustments

Q. BRIEFLY DESCRIBE THE REVENUE REQUIREMENT INCREASE BEING REQUESTED BY WELLSBORO IN THIS CASE.

A. Wellsboro Electric Company ("Wellsboro" or "the Company") is requesting a $2,899,166 increase in annual distribution revenue, representing a 45.3% increase

over present distribution rates. The requested increase is based on a Fully Projected Future Test Year ("FPFTY") ending December 31, 2026, and is designed to produce an overall rate of return of 8.18% on Wellsboro's rate base.[1]

Q. DO YOU HAVE ANY RECOMMENDED ADJUSTMENTS TO WELLSBORO'S PROPOSED REVENUE REQUIREMENT?

A. Yes. My recommended adjustments would reduce Wellsboro's proposed revenue requirement increase by $386,239. As discussed in greater detail later in my testimony, this reduction incorporates a proxy return on equity ("ROE") of 10.0%, which is derived from the ROE authorized by the Commission for the Distribution System Improvement Charge ("DSIC") applicable to most electric utilities in the state. Table JBF-1 presents a summary of my recommended adjustments.

Table JBF-1
Summary of OSBA Adjustments to Wellsboro's Revenue Requirement

	OSBA Adjustments	Revenue Requirement
Revenue Requirement Increase Requested by Wellsboro		**2,899,388**
O&M Adjustment		
Account 921 Adjustment	(25,365)	
Income Tax Rate Adjustment		
Change PA Income Tax Rate from 9.99% to 7.49%	(135,283)	
Proxy Return on Equity		
Change ROE from 11.65% to Proxy 10%	(210,283)	
Impact of GRT gross up	(23,257)	
Rounding	7,949	
Adjusted Revenue Requirement Increase		**2,513,149**

[1] Direct Testimony of Howard S. Gorman (Wellsboro Statement No. 1), page 3.

I provide more detail for each of these recommended adjustments as follows:

Account 921 Adjustment

Q. PLEASE DESCRIBE ACCOUNT 921 – OFFICE SUPPLIES AND EXPENSES.

A. Account 921 covers general administrative office supplies and expenses related to company operations that are not specifically counted elsewhere. There are no labor costs included in Account 921. Wellsboro has subdivided Account 921 into the following sub-accounts:

- 921 – Office Supplies and Expense
- 921.1 – Utilities
- 921.4 – Subscriptions
- 921.5 – Office Supplies
- 921.6 – WECO Telephone
- 921.7 – Dispatch Telephone
- 921.8 – Data Circuit #008
- 921.9 – MISC
- 921.99 – Working Capital Claim-Admin

Q. BRIEFLY DESCRIBE HOW WELLSBORO CALCULATED FPFTY 2026 EXPENSES FOR ACCOUNT 921.

A. Wellsboro adjusted HTY 2024 values for each sub-account individually to forecast FTY 2025 values. FPFTY 2026 values for all 921 sub-accounts, except 921.99, were projected to equal FTY 2025 values. In other words, Wellsboro assumed no escalation between FTY 2025 and FPFTY 2026 for sub-accounts 921 through 921.9. Sub-account 921.99 – Working Capital Claim-Admin, which is an offset to 921 expenses was projected to increase 16%. An increase in sub-account 921.99 reduces total 921 expenses.

Wellsboro estimated the total for Account 921 to equal $123,007 in FTY 2025 and $109,710 in FPFTY 2026, which represents a 9% increase over HTC 2024 and an 11% decrease over FTY 2025, respectively. When asked to explain the 9% increase between HTY 2024 and FTY 2025, Wellsboro responded: "From HTY 2024 to FTY 2025, Account #921 reflects modest increases and/or decreases across most expense categories".[2]

Q. WHAT IS ACTUALLY HAPPENING TO SUB-ACCOUNTS IN 921?

A. Sub-accounts within Account 921 are projected to experience annual changes between HTY 2024 and FTY 2025 ranging from a reduction of 34% (921.4 – Subscriptions) to an increase of 164% (921.5 – Office Supplies).[3] These annual projected changes run contrary to Wellsboro's assertion that assumptions driving changes between HTY 2024 and FTY 2025 in Account #921 "reflect modest increases and/or decreases across most expense categories."

Q. WHAT IS YOUR RECOMMENDED ADJUSTMENT TO ACCOUNT 921?

A. I recommend limiting the allowed increase in sub-account 921.5 – Office Supplies from 164% to 2.00% and the increase in sub-account 921.9 – MISC from 128% to 2.00%. Limiting these accounts to 2.00% escalation between HTY 2024 and FTY 2025 still allows the total Account 921 to grow at a compound annual growth rate of 10.9% between 2023 and FPFTY 2026 which is a healthy escalation rate. This is largely attributable to the 82% increase in Account 921 between 2023 and HTY 2024. A comparison of growth rates between Wellsboro's requested amounts and OSBA's proposed amounts is found in Table JBF-2.

[2] Wellsboro response to I&E-RE-18-D-C.
[3] JBF WP-2 Account 921

Table JBF-2
Comparison of Growth Rates in Account #921

Wellsboro Requested

Acct. #	Account Description	Annual % Change 2023-24	2024-25	2025-26	CAGR 2023-2026
921.5	Gen Office - Office Supp	37.6%	163.6%	0.0%	53.6%
921.9	Gen Office - MISC	-11.7%	128.5%	0.0%	26.4%
921.99	Working Capital Claim-Admin	-20.8%	23.9%	16.3%	4.5%
Other 921	All Other 921 Sub-Accounts	25.2%	0.1%	0.0%	7.8%
	Total	**82.3%**	**9.0%**	**-10.8%**	**21.0%**

OSBA Proposed

Acct. #	Account Description	Annual % Change 2023-24	2024-25	2025-26	CAGR 2023-2026
921.5	Gen Office - Office Supp	37.6%	2.0%	0.0%	12.0%
921.9	Gen Office - MISC	-11.7%	2.0%	0.0%	-3.4%
921.99	Working Capital Claim-Admin	-20.8%	23.9%	16.3%	4.5%
Other 921	All Other 921 Sub-Accounts	25.2%	0.1%	0.0%	7.8%
	Total	**82.3%**	**-13.5%**	**-13.6%**	**10.8%**

Q. WHAT IS THE IMPACT OF THIS ADJUSTMENT?

A. As reported in Table JBF-1, capping sub-accounts 921.5 and 921.9 at 2.00% inflation in FTY 2025 reduces revenue requirement by $25,365 in FPFTY 2026.

Pennsylvania Corporate Income Tax Rate Adjustment

Q. DESCRIBE THE PENNSYLVANIA CORPORATE NET INCOME TAX RATE AND ITS HISTORY.

A. For nearly three decades, Pennsylvania maintained a flat Corporate Net Income ("CNI") Tax rate of 9.99%, among the highest in the United States. This rate remained unchanged from 1995 until 2022. In July 2022, the Pennsylvania General Assembly enacted Act 53-2002 (H.B. 1342), initiating a phased reduction

of the CNI Tax rate over nine years. The schedule for the rate reductions is as follows[4]:

Table JBF-3
Pennsylvania Corporate Net Income Tax Rates

Tax Year	CNIT Rate
January 1, 2023 - December 31, 2023	8.99 percent
January 1, 2024 - December 31, 2024	8.49 percent
January 1, 2025 - December 31, 2025	7.99 percent
January 1, 2026 - December 31, 2026	7.49 percent
January 1, 2027 - December 31, 2027	6.99 percent
January 1, 2028 - December 31, 2028	6.49 percent
January 1, 2029 - December 31, 2029	5.99 percent
January 1, 2030 - December 31, 2030	5.49 percent
January 1, 2031 and each taxable year thereafter	4.99 percent

Q. WHAT PENNSYLVANIA CNI TAX RATE WAS USED IN THE DEVELOPMENT OF THE COMPANY'S REQUESTED INCREASE IN REVENUE REQUIREMENT IN THIS CASE?

A. The Company used 9.99% as the Pennsylvania corporate income tax rate.[5]

Q. WHAT PENNSYLVANIA CNI TAX RATE DO YOU RECOMMEND?

A. I recommend using 7.49% as the CNI Tax rate for FPFTY 2026, which is the tax rate enacted by Act 53-2022 for calendar year 2026, and to require the company to reflect actual CNI rates for the post-2026 tax years through the Company's State Tax Adjustment Surcharge until the next rate case proceeding.

Q. WHAT IS THE IMPACT OF THIS ADJUSTMENT?

A. As reported in Table JBF-1, this adjustment would reduce revenue requirement by $135,283 in FPFTY 2026.

[4] https://www.pa.gov/agencies/revenue/resources/tax-rates/corporation-tax-rates.html
[5] Direct Testimony of Howard S. Gorman (Wellsboro Statement No. 1), page 11.

Adjustments to the Common Equity Cost Rates

Q. WHAT IS THE PERFORMANCE FACTOR ADJUSTMENT?

A. Wellsboro witness Byron Farnsworth, Jr. explains that Section 523 of the Public Utility Code provides the Commission's guidelines for performance adjustments. He states that counsel has advised him that the Public Utility Code identifies several criteria to be considered in assessing the performance of a fixed utility for purposes of a performance factor adjustment, including consideration of any relevant and material evidence of efficiency, effectiveness, and adequacy of service. Mr. Farnsworth provides information on Wellsboro's operations, which he asserts support receiving a performance factor adjustment.[6]

Q. WHAT IS WELLSBORO'S PROPOSED PERFORMANCE FACTOR ADJUSTMENT?

A. Wellsboro proposes a performance factor adjustment of a 5-basis point addition to the cost of common equity.[7]

Q. WHAT IS YOUR RESPONSE TO WELLSBORO'S PROPOSED PERFORMANCE FACTOR ADJUSTMENT?

A. Utilities are expected to provide safe and reliable service to their customers. They should also deliver quality customer service, upgrade their systems, and manage their costs effectively. Utilities already receive a guaranteed rate of return for performing these functions. Providing an additional upward adjustment for effective operations, at the expense of customers, is excessive.

Q. WHAT IS THE SIZE ADJUSTMENT?

[6] Direct Testimony of Byron Farnsworth, Jr. (Wellsboro Statement No.4), pp. 8-10.
[7] Revised Direct Testimony of Dylan W. D'Ascendis (Joint Statement No. 2), page 52.

A. Wellsboro witness Dylan D'Ascendis explains that the Companies' smaller size relative to the Electric Utility Proxy Group indicates greater relative business risk for the Company because, all else being equal, size has a material bearing on risk. He asserts that size affects business risk because smaller companies generally are less able to cope with significant events that affect sales, revenues and earnings. For example, smaller companies face more risk exposure to business cycles and economic conditions, both nationally and locally. Additionally, Mr. D'Ascendis states that the loss of revenue from a few larger customers would have a greater effect on a small company than on a bigger company with a larger, more diverse, customer base.[8]

Q. WHAT IS WELLSBORO'S PROPOSED SIZE ADJUSTMENT?

A. Wellsboro proposes a size factor adjustment of an 85-basis point addition to the cost of common equity.[9]

Q. WHAT IS YOUR RESPONSE TO WELLSBORO'S PROPOSED SIZE FACTOR ADJUSTMENT?

A. The Company's arguments for an upward adjustment focus solely on potential losses, without acknowledging the possibility of potential gains. While it is true that a small company losing a large customer could experience reduced revenues, it is also possible for the company to gain large customers, therefore increasing revenues. At the very least, new customers could offset the impact of losing existing ones. Customers should not bear the burden of shielding a utility from every possible risk, particularly when utilities have the ability to file a rate case

[8] Revised Direct Testimony of Dylan W. D'Ascendis (Joint Statement No. 2), page 47.
[9] Revised Direct Testimony of Dylan W. D'Ascendis (Joint Statement No. 2), page 51.

with the Commission to address extreme risks if they arise. An 85-basis-point upward adjustment to account for unspecified risks is excessive.

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE PERFORMANCE FACTOR ADJUSTMENT AND THE SIZE FACTOR ADJUSTMENT?

A. I recommend eliminating the performance factor adjustment entirely and lowering or removing the size factor adjustment. These changes support, and help justify, a lower return on equity ("ROE") for the company, which I will discuss in greater detail below.

Proxy Return on Equity Adjustment

Q. WHAT ROE IS WELLSBORO REQUESTING IN THIS PROCEEDING?

A. Wellsboro witness Dylan W. D'Ascendis recommends a ROE of 11.65%.[10]

Q. DO YOU SUPPORT WELLSBORO'S REQUESTED ROE?

A. No.

Q. WHAT OBSERVATIONS HAVE YOU MADE IN REGARD TO WELLSBORO'S REQUESTED ROE?

A. A comparison of Wellsboro's requested ROE of 11.65% with the most recent Report on the Quarterly Earnings of Jurisdictional Utilities for the year ending December 31, 2024, produced by the Bureau of Technical Utility Services indicates to me that the requested 11.65% is too high and should be adjusted down. Based on the report, the current market indicated ROE as calculated by the

[10] Revised Direct Testimony of Dylan W. D'Ascendis (Joint Statement No. 2), page 6.

Bureau of Technical Utility Services should fall within the range of 9.17% to 11.23%[11]. This report is included as Exhibit JBF-1 at the end of my testimony.

A review of recently completed rate cases across the country for electric distribution companies that were either settled, or fully litigated within the last year, suggests that the proper ROE is likely near the lower part of the range provided by the Bureau of Technical Utility Services. The average authorized ROE in cases involving electric distribution companies that were approved between June 1, 2024, and June 30, 2025, is 9.50%. Expanding the universe of approved rate cases to include vertically integrated electric utilities over the same period increases the authorized ROE to 9.77%. A detailed listing of approved ROE's from rate cases finalized over the last year is included at the end of my testimony as Exhibit JBF-2. I present the results for electric distribution utilities in Table JBF-4.

Table JBF-4
Survey of Approved ROE's for Electric Distribution Companies Between June 1, 2024 & June 30, 2025

State	Company	Case identification	Approved Date	ROE (%)
MD	Potomac Electric Power Company	C-9702	6/10/2024	9.50
MA	Fitchburg Gas and Electric Light Company, In	DPU 23-80	6/28/2024	9.40
NY	Central Hudson Gas & Electric Corporation	C-23-E-0418	7/18/2024	9.50
MA	Massachusetts Electric Company	DPU 23-150	9/30/2024	9.35
DC	Potomac Electric Power Company	FC-1176	11/25/2024	9.50
ME	Versant Power	D-2023-00336	3/13/2025	9.35
TX	AEP Texas Inc.	D-56165	10/3/2024	9.76
NJ	Public Service Electric and Gas Company	D-ER23120924	10/9/2024	9.60
TX	CenterPoint Energy Houston Electric, LLC	D-56211	3/13/2025	9.65
NY	Orange and Rockland Utilities, Inc.	C-24-E-0060	3/20/2025	9.75
NH	Liberty Utilities (Granite State Electric) Corp.	D-DE-23-039	3/25/2025	9.10

[11] Exhibit JBF-1, Report on the Quarterly Earnings of Jurisdictional Utilities (Year ending December 31, 2024, page 14.

Q. DO YOU RECOMMEND A SPECIFIC ROE?

A. No, I do not have a recommendation for a specific ROE but rather defer to analysis and recommendations promulgated by the Office of Consumer Advocate ("OCA") and the Bureau of Investigation and Enforcement ("I&E"). However, for purposes of my testimony, I have assumed a proxy 10.0% ROE based upon the Commission's approved ROE for Distribution System Improvement Charge (DSIC) included in the most recent Report on the Quarterly Earnings of Jurisdictional Utilities[12] for the year ended December 31, 2024, produced by the Bureau of Technical Utility Services referenced previously.

Q. WHAT IS THE REVENUE REQUIREMENT IMPACT OF USING A PROXY 10.0% ROE?

A. As reported in Table JBF-1, this adjustment would reduce revenue requirement by $210,283 in FPFTY 2026.

Section III - Class Cost of Service and Revenue Allocation

Q. DID WELLSBORO PERFORM A CLASS COST OF SERVICE STUDY?

A. Yes, Wellsboro completed an allocated class cost of service study ("ACOS") that follows the traditional three-step process of: 1) functionalization of rate base and costs; 2) classification of functionalized costs as demand-related, commodity-related or customer-related; and 3) class allocation of the functionalized, classified costs among the rate classes.

[12] Exhibit JBF-1, Report on the Quarterly Earnings of Jurisdictional Utilities (Year ending December 31, 2024, page 15.

Q. DO YOU HAVE ANY COMMENTS ON THE COST ALLOCATION METHODS USED BY WELLSBORO?

A. Yes. As a general matter, I find the cost allocation methods employed by Wellsboro, as outlined by Mr. Gorman, to align with the principles of cost causation. Therefore, I am not proposing any modifications to the Company's cost allocation approach in this proceeding.

Q. PLEASE DESCRIBE WELLSBORO'S REVENUE ALLOCATION PROPOSAL.

A. Wellsboro revenue allocation proposal is guided by the objectives of 1) moving each class closer to cost of service as computed in the ACOS, and 2) mitigating extreme rate impacts on rate classes and on customer subgroups.[13]

Q. WHAT IS YOUR ASSESSMENT OF WELLSBORO'S REVENUE ALLOCATION PROPOSAL?

A. The Company's revenue allocation proposal reasonably balances moving class revenue recovery in the direction of cost causation. Most classes have reductions in the subsidy paid or received. In my opinion, the proposed revenue allocation falls within the range of reasonableness.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

[13] Direct Testimony of Howard S. Gorman (Wellsboro Statement No. 1), page 28.

APPENDIX A

Vitae & Expert Testimony List

of

Justin B. Farr

APPENDIX A

Justin B. Farr

Director, Energy Strategies, L.L.C.
111 East Broadway, Suite 1200, Salt Lake City, UT 84111
jfarr@energystrat.com

Vitae

Professional Experience

Energy Strategies, Salt Lake City UT, April 2022 - Present
An energy consulting firm focused on regulatory services, policy, and markets serving power producers, transmission developers, utilities, government agencies, NGO's, and large energy users

Director

- Perform energy-related economic and policy analysis, regulatory intervention, and strategic negations on behalf of industrial, commercial, and public sector interests
- Provide risk management and market fundamentals analysis to large consumers of natural gas
- Executive director of the Utah Association of Energy Users

PacifiCorp, Salt Lake City UT, January 2020 – April 2022
Berkshire Hathaway owned electric utility serving over 1.6 million customers in Utah, Oregon, Washington, Wyoming, Idaho, and parts of Northern California

Assistant Manager of Regulation, March 2021 – April 2022
Senior Fuels Manager, January 2020 – March 2021

- Performed rate projections tied to the company's 10-year plan
- Provided testimony on the Renewable Energy Credits balancing account
- Procured fuel and managed contracts for company owned and jointly owned thermal plants

Magnum Development, Holladay UT, 2017 – Oct 2019
Private Equity backed developer of utility-scale storage in underground salt caverns. Developing storage for natural gas, compressed air created from renewable electricity, green hydrogen, and helium.

Vice President of Financial Planning, January 2019 – October 2019
Assistant Vice President of Financial Planning, February 2017 – December 2018

- Worked on commercial team developing bidding strategies and analysis to support joint development negotiations

- Managed all financial and economic modeling across all of Magnum's business verticals including: Magnum Midstream (Natural Gas), Magnum Compressed Air Energy Storage (CAES), Magnum Hydrogen, and Magnum Industrial Gases (Helium)

PacifiCorp, Salt Lake City UT, 2013 – 2017
Berkshire Hathaway owned electric utility serving over 1.6 million customers in Utah, Oregon, Washington, Wyoming, Idaho, and parts of Northern California

Manager Economic & Financial Analysis, August 2015 – February 2017
Senior Financial Planning Analyst, October 2013 – August 2015

- Managed team of Sr. Financial Analysts responsible for economic analysis, internal audit of joint owned plants, and annual budget of resource development division
- Led team of engineers, plant managers, and vice presidents in developing economic solutions that optimized existing thermal and renewable infrastructure investment
- Developed economic models to explore new resource development opportunities such as utility scale solar and battery installations
- Prepared annual cost of generation report for senior management

Energy Strategies, Salt Lake City UT, 2005 – 2013
An energy consulting firm focused on regulatory services, policy, and markets serving power producers, transmission developers, utilities, government agencies, NGO's, and large energy users

Senior Consultant, January 2010 – October 2013
Consultant, July 2005 – December 2009

- Developed strategies for clients with energy infrastructure that optimized environmental performance and financial objectives while meeting their utility requirements
- Performed market studies focused on thermal & renewable energy need, transmission availability, pricing, and impacts of public policy initiatives. Studies were designed to inform and improve clients' energy decisions including risk management and procurement strategy.

Education

- Master of Business Administration, University of Utah, May 2005
- Bachelor of Science in Economics/Business Minor, University of Utah, May 2000
- Graduated Magna Cum Laude; GPA 3.92
- Honors at Entrance Scholarship; 1999-2000 Law & Economic Society Fellowship

Expert Testimony

"In the Matter of the Petition of PPL Electric Utilities Corp for Approval of its Second Distributed Energy Resources Management Plan," Public Utilities Commission of **Pennsylvania**, Docket No. P-2024-3049223. Direct testimony submitted September 17, 2024. Surrebuttal testimony filed January 22, 2024.

"In the Matter of the Verified Petition of Indiana Michigan Power Company for Approval of Modifications to its Industrial Power Tariff – Tariff IP," **Indiana** Utility Regulatory Commission, Cause No. 46097. Direct testimony submitted October 15, 2024. Cross-Answering testimony filed November 4, 2024. Settlement testimony filed December 4, 2024.

"In the Matter of the Application of Rocky Mountain Power for Authority to Revise Rates in Tariff Schedule 98, Renewable Energy Credits Balancing Account," **Utah** Public Service Commission, Docket No. 22-035-07. Direct testimony submitted March 15, 2022.

EXHIBIT JBF-1

PENNSYLVANIA PUBLIC UTILITY COMMISSION

Public Meeting held May 8, 2025

Docket Number: M-2025-3054401

BUREAU OF TECHNICAL UTILITY SERVICES

REPORT ON THE QUARTERLY EARNINGS

OF JURISDICTIONAL UTILITIES

FOR THE YEAR ENDED

December 31, 2024

Stephen M. DeFrank, Chairman
Kimberly Barrow, Vice Chair
Kathryn L. Zerfuss
John F. Coleman, Jr., Joint Statement, Dissenting
Ralph V. Yanora, Joint Statement, Dissenting

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Historic barometer group DCF and CAPM average ROEs, including a linear trend line graph.

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Introduction:

On September 20, 1991, the Commission initiated a rulemaking at L-00910061 pertaining to earnings disclosures by the public utilities subject to its jurisdiction. At that docket, the Commission stated that the submission of accurate, reliable, and complete earnings disclosure reports, at regular intervals, is essential to the fulfillment of the broad regulatory oversight responsibilities entrusted to the Commission by the Legislature in the Public Utility Code. The earnings disclosure regulations promulgated by the Commission were adopted October 1, 1992, and published January 23, 1993, at 23 Pa.B. 463. Based upon those regulations, codified at 52 Pa. Code, Chapter 71, a reporting format was developed and distributed to the jurisdictional fixed utilities of Pennsylvania.

All fixed utilities having jurisdictional revenues of $1,000,000 or more, for a calendar year, are required to file the report by March 31 of each year. Such reports are to be based upon the results of operations for the 12-month period ending December 31 of the prior year. Utilities having more than $10,000,000 in jurisdictional revenues are also required to file reports for the 12 months ending on March 31, June 30, and September 30 of each year.[1] On November 30, 2004, however, the Pennsylvania General Assembly signed into law Act 183 concerning alternative telecommunications regulation and broadband deployment. As a result of Act 183, the reporting requirements for the PUC jurisdictional telecommunications companies of Pennsylvania have been streamlined at section 3015(e) of the Public Utility Code. A quarterly earnings report is not listed among those reports now required of PUC jurisdictional telecommunications utilities in Pennsylvania and, therefore, this report does not address telephone company earnings.

The reports have been filed for the period ending December 31, 2024, at Docket No. M-2025-3052807.[2] The Finance Staff of the Bureau of Technical Utility Services has reviewed the reports and has prepared this summary report for public release. This report sets forth the achieved return on equity for each company, the last allowed return for that utility, a market return as determined through the analysis of the barometer group data and the most recent returns allowed, per industry, by the Pennsylvania Public Utility Commission and by other regulatory bodies. Where a utility has not filed a report, the reasons for not filing are indicated.

Questions pertaining to the preparation and contents of this Report should be directed to Mr. Marc Hoffer, Manager - Finance, Bureau of Technical Utility Services, at (717) 787-1869.

[1] Per Commission regulations at 52 Pa. Code § 71.3(a)(1), the major electric utilities are specifically identified by name rather than utilizing the $10,000,000 revenue threshold utilized by gas and water utilities.

[2] Columbia Gas of PA Inc., UGI Utilities, Inc. – Gas Division, and FirstEnergy Pennsylvania Electric Co. have rate filings at Docket Nos. R-2025-3053499, R-2024-3052716, and R-2024-3047068, respectively, and have filed a letter with the Secretary in place of a report in accordance with 52 Pa. Code § 71.4.

Attachment A

The equity return summaries that follow in Attachment A are, for each quarter;

ACTUAL

1. Based on actual results of operations

and

ADJUSTED

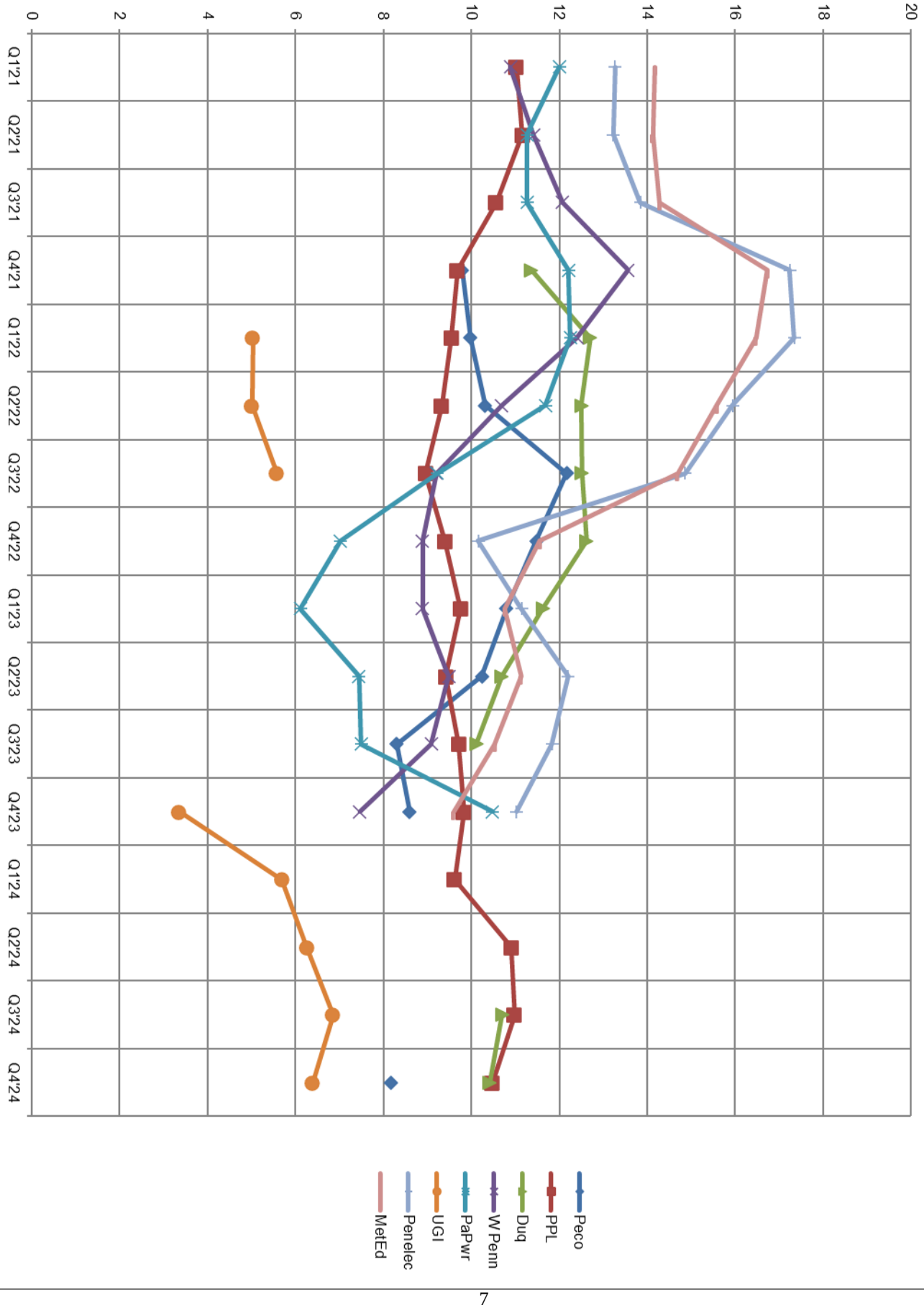
2. Based on company proposed pro forma and ratemaking adjustments

Attachment A

ELECTRIC UTILITIES
EQUITY RETURNS BY QUARTER

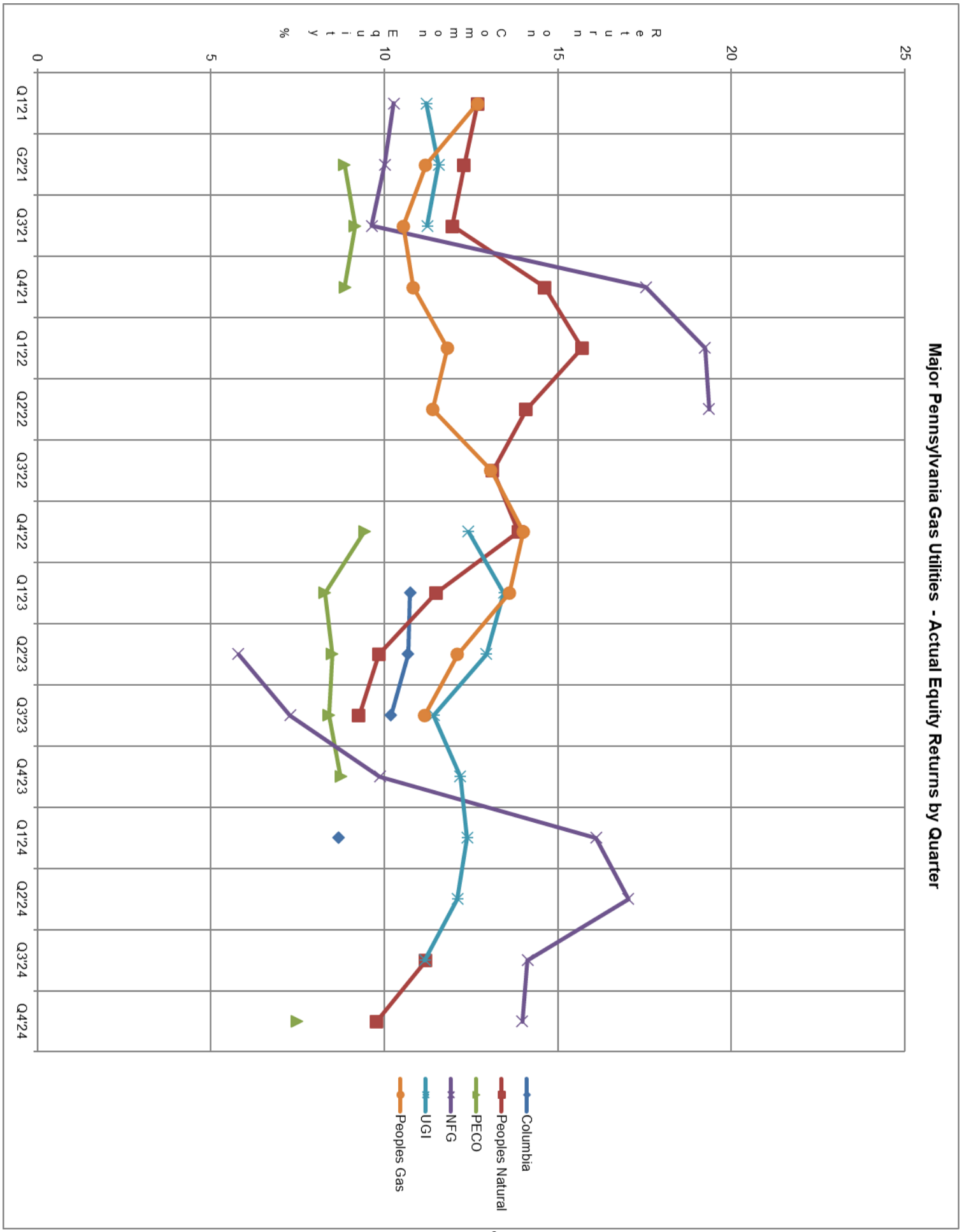
QTR END		Peco		PPL		Duq		W Penn		PaPwr		UGI		Penelec		MetEd	
		ACT	ADJ	ACT	ADJ	ACT	ADJ	ACT	ADJ	ACT	ADJ	ACT	ADJ	ACT	ADJ	ACT	ADJ
2018	1			12.53	11.36			10.35	9.08	9.03	8.08			11.84	9.93	12.77	11.38
	2			11.05	9.49			9.92	8.52	8.79	7.57			11.56	9.39	11.90	10.26
	3			11.19	9.83			11.41	6.74	10.30	5.80			13.97	8.44	14.46	9.62
	4	10.88	7.61	11.10	10.15	12.06	9.39	9.92	6.78	10.64	7.43			13.27	9.31	13.05	7.40
2019	1	12.65	7.93	10.10	8.96	12.58	9.73	9.08	6.62	9.14	7.61	7.05	5.22	12.03	8.07	12.54	7.66
	2	12.34	7.94	10.51	8.95	12.38	9.34	8.02	5.99	8.29	7.10	5.77	3.22	11.42	8.16	11.72	7.21
	3	12.49	7.96	10.61	8.99	13.88	9.33	9.90	7.87	9.28	7.76	6.20	2.04	11.26	8.78	12.25	7.77
	4	12.21	8.50	10.53	10.40	13.92	9.08	14.13	7.07	8.08	6.90	7.20	2.38	10.02	8.54	10.96	9.27
2020	1	11.31	8.35	10.84	11.20	12.66	8.31	9.82	5.54	5.06	6.71	5.43	2.26	7.24	8.74	7.20	8.31
	2	9.38	8.17	11.20	10.81	12.73	8.56	10.41	5.53	5.56	6.55	6.06	2.01	6.68	7.94	7.34	8.04
	3	9.62	8.56	11.14	11.20	12.32	8.08	10.22	5.42	5.62	6.74	7.76	0.41	7.87	8.75	7.64	8.37
	4	9.16	7.64	11.10	11.48	12.57	8.15	7.48	5.65	11.36	7.34			10.08	8.62	9.91	8.64
2021	1			11.03	11.76			10.89	6.64	12.01	7.01			13.27	8.96	14.19	9.44
	2			11.17	11.73			11.42	7.07	11.27	5.94			13.23	8.15	14.13	9.06
	3			10.57	10.65			12.08	7.91	11.27	5.91			13.85	8.67	14.29	9.38
	4	9.79	7.59	9.69	10.57	11.37	11.23	13.57	7.85	12.21	5.42			17.25	8.04	16.74	9.40
2022	1	9.98	6.99	9.55	9.49	12.71	10.91	12.40	6.99	12.26	5.30	5.03	4.93	17.35	7.83	16.48	9.40
	2	10.32	7.19	9.33	9.54	12.51	10.22	10.70	5.78	11.69	5.04	5.01	3.89	15.95	6.93	15.59	8.72
	3	12.17	7.42	8.97	9.14	12.52	9.74	9.21	4.43	9.23	4.35	5.58	0.65	14.87	5.88	14.70	7.57
	4	11.48	6.59	9.41	9.18	12.62	9.54	8.89	4.19	7.03	3.44			10.16	5.07	11.56	7.55
2023	1	10.80	6.47	9.76	9.36	11.63	9.53	8.89	5.32	6.11	4.01			11.15	6.88	10.77	8.25
	2	10.24	6.19	9.43	8.67	10.69	9.39	9.49	6.03	7.45	5.58			12.20	7.90	11.14	8.81
	3	8.30	5.48	9.72	8.12	10.12	8.89	9.09	5.96	7.50	5.76			11.84	7.79	10.54	8.60
	4	8.60	5.19	9.84	8.49			7.47	6.02	10.49	7.09	3.36	4.48	11.03	8.17	9.61	8.66
2024	1			9.63	8.22							5.70	2.03				
	2			10.92	9.17							6.26	1.11				
	3			10.99	9.46	10.71	9.16					6.86	1.70				
	4	8.17	4.22	10.49	7.23	10.42	9.38					6.40	1.41				

Major Pennsylvania Electric Utilities - Actual Equity Returns by Quarter



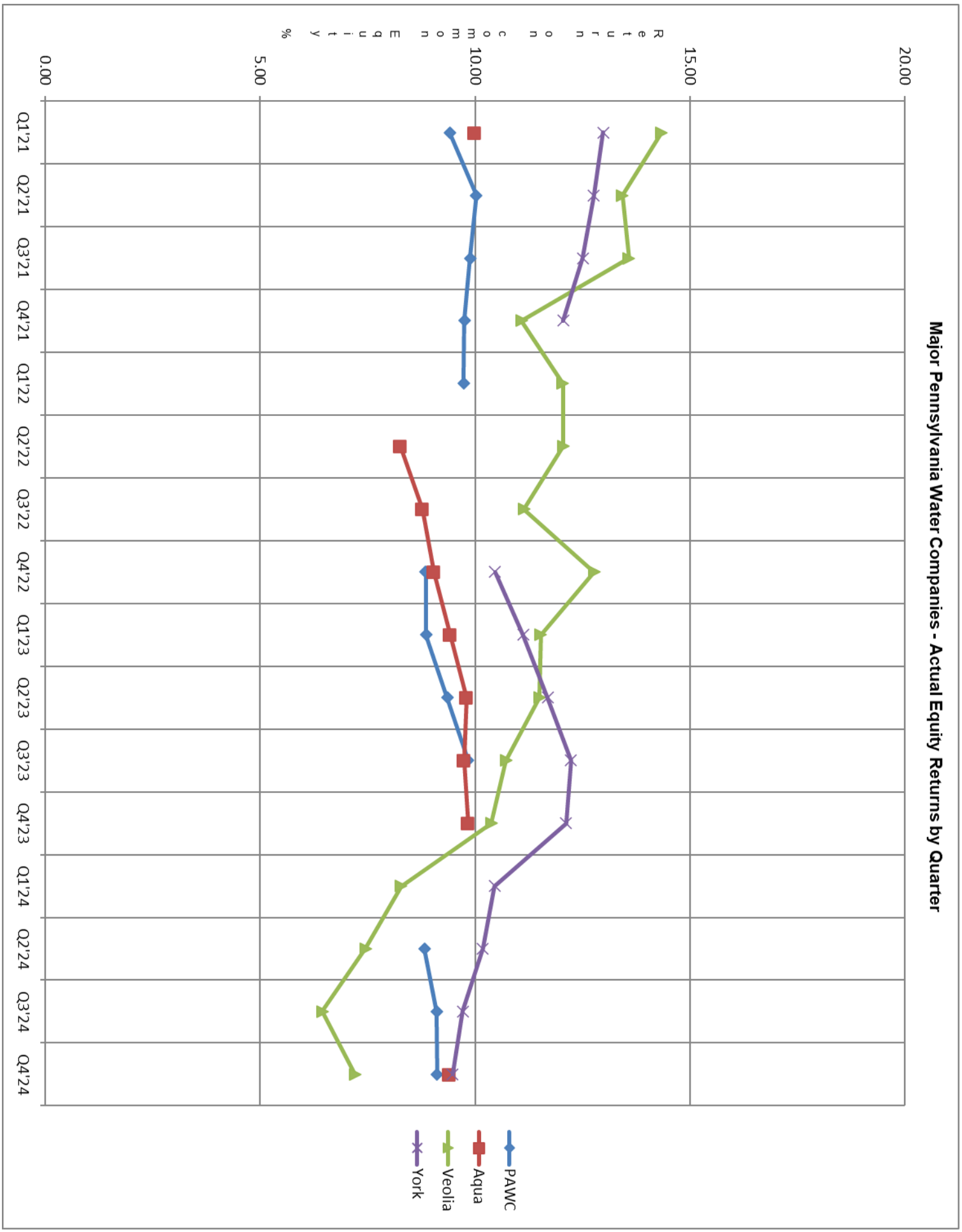
GAS UTILITIES
EQUITY RETURNS BY QUARTER

QTR		Columbia		Peoples Natural		PECO		NFG		UGI		Peoples Gas	
END		ACT	ADJ	ACT	ADJ	ACT	ADJ	ACT	ADJ	ACT	ADJ	ACT	ADJ
2018	1			11.42	7.00	12.65	9.77	14.40	10.20	12.82	7.90	14.02	10.17
	2			11.03	6.80	12.66	9.05	12.06	9.89	16.75	6.80	12.78	10.15
	3			10.21	7.43	12.54	8.36	12.52	10.12	18.69	8.04	13.03	10.20
	4	11.39	9.81			12.86	8.68	12.24	10.21			13.92	11.13
2019	1	12.76	10.22			13.68	9.06	11.83	10.93			14.10	10.71
	2	12.04	9.92			12.62	8.41	14.56	9.99			13.80	11.66
	3	11.77	9.85			12.40	8.31	14.17	9.75			14.02	11.63
	4	9.21	9.09	10.74	12.26	11.75	6.99	14.20	9.77			12.76	11.20
2020	1	8.42	9.11	12.34	12.34	10.84	7.68	11.82	9.92			11.40	11.07
	2			13.81	12.38	11.26	7.25	11.28	9.05			11.89	11.10
	3			14.60	12.77			10.39	8.25			11.82	11.50
	4			12.09	10.37			9.68	8.12			12.93	12.11
2021	1			12.69	10.43			10.27	8.47	11.22	7.70	12.69	11.76
	2			12.31	10.23	8.85	5.13	10.02	8.47	11.57	8.04	11.20	11.61
	3			11.97	10.27	9.16	5.27	9.64	8.45	11.24	6.97	10.56	11.38
	4			14.62	10.52	8.86	5.79	17.54	8.02			10.84	10.28
2022	1			15.71	10.93			19.24	7.88			11.83	12.09
	2			14.09	11.67			19.36	6.87			11.40	12.19
	3			13.13	10.30							13.08	11.31
	4			13.87	10.56	9.43	5.93			12.42	7.62	14.01	14.19
2023	1	10.75	10.30	11.50	9.02	8.29	6.05			13.45	8.33	13.61	12.68
	2	10.68	10.33	9.85	9.50	8.50	6.20	5.80	9.98	12.94	8.97	12.12	13.84
	3	10.19	10.72	9.28	8.17	8.41	6.01	7.29	9.58	11.43	8.27	11.17	14.22
	4					8.75	6.82	9.87	10.80	12.19	7.44		
2024	1	8.67	9.61					16.10	10.64	12.39	7.55		
	2							17.03	9.78	12.11	6.91		
	3			11.20	9.07			14.13	8.63	11.17	6.45		
	4			9.78	8.84	7.49	5.56	13.98	8.62				


Major Pennsylvania Gas Utilities - Actual Equity Returns by Quarter
Return on Common Equity %
0
5
10
15
20
25
Q1'21
Q2'21
Q3'21
Q4'21
Q1'22
Q2'22
Q3'22
Q4'22
Q1'23
Q2'23
Q3'23
Q4'23
Q1'24
Q2'24
Q3'24
Q4'24
Columbia
Peoples Natural
PECO
NFG
UGI
Peoples Gas

WATER UTILITIES
EQUITY RETURNS BY QUARTER

QTR		PAWC		Aqua		Veolia		York	
END		ACT	ADJ	ACT	ADJ	ACT	ADJ	ACT	ADJ
2018	1	9.55	8.97	10.94	8.41				
	2	10.27	9.65						
	3	11.03	9.48						
	4	10.08	9.03					10.70	10.30
2019	1	9.82	8.87					11.60	11.60
	2	9.72	8.90	9.84	9.04	10.78	10.36	11.80	11.80
	3	9.13	8.41	10.69	8.84	11.55	11.75	12.00	12.00
	4	8.71	8.09	10.33	8.24	11.80	12.15	12.00	9.80
2020	1	8.74	7.56	10.47	8.31	11.30	11.30	12.39	12.39
	2			10.81	8.57	10.72	10.69	12.51	12.51
	3			10.33	8.55	11.13	10.69	13.76	13.76
	4	8.90	8.15	9.89	8.30	13.98	10.17	13.42	9.94
2021	1	9.41	8.90	9.99	8.38	14.34	10.48	12.98	9.74
	2	10.03	9.28			13.43	9.83	12.76	9.66
	3	9.89	8.65			13.58	9.07	12.51	9.32
	4	9.75	8.05			11.08	9.75	12.05	8.86
2022	1	9.73	7.82			12.04	9.68		
	2			8.26	8.91	12.05	9.79		
	3			8.78	8.85	11.14	9.30		
	4	8.85	8.97	9.04	8.88	12.77	9.49	10.47	10.57
2023	1	8.86	8.90	9.42	8.48	11.53	8.98	11.12	11.12
	2	9.35	8.89	9.80	8.52	11.50	8.91	11.69	11.69
	3	9.84	8.93	9.74	8.39	10.72	8.42	12.23	12.23
	4			9.84	8.35	10.38	7.64	12.12	8.16
2024	1					8.28	6.49	10.46	7.99
	2	8.82	8.56			7.46	5.70	10.18	8.00
	3	9.11	8.49			6.45	5.42	9.72	7.31
	4	9.12	8.44	9.40	9.29	7.21	5.36	9.48	7.10


Major Pennsylvania Water Companies - Actual Equity Returns by Quarter
Return on Common Equity %
20.00
15.00
10.00
5.00
0.00
Q1'21
Q2'21
Q3'21
Q4'21
Q1'22
Q2'22
Q3'22
Q4'22
Q1'23
Q2'23
Q3'23
Q4'23
Q1'24
Q2'24
Q3'24
Q4'24
PAWC
Aqua
Veolia
York

Attachment B includes:

A. Overall Returns on rate base
1. Actual
2. Company proposed pro forma and ratemaking adjustments

and

B. Equity Returns
1. Actual
2. Company proposed pro forma and ratemaking adjustments

Summary of Returns
For the Year Ended December 31, 2024

COMPANY NAME	OVERALL RETURN ACTUAL	OVERALL RETURN ADJ	EQUITY RETURN ACTUAL	EQUITY RETURN ADJ	ROE AUTH	YEAR AUTH
ELECTRIC						
Major Electric Utilities						
PECO Energy - Electric Operations	6.31	4.10	8.17	4.22	Settled	2024
PPL Electric Utilities Corp.	7.99	6.06	10.49	7.23	Settled	2015
Duquesne Light Company	7.89	7.24	10.42	9.38	Settled	2024
West Penn Power Company*					Settled	2024
Pennsylvania Power Company*					Settled	2024
UGI Utilities, Inc. - Electric Division	5.57	3.18	6.40	1.41	Settled	2023
Pennsylvania Electric Company*					Settled	2024
Metropolitan Edison Company *					Settled	2024
Over $1,000,000						
Revenues						
Pike County Light & Power Co.	6.21	6.21	5.98	5.98	Settled	2021
Citizens Electric Company	6.30	8.03	6.58	8.54	Settled	2022
Wellsboro Electric Company	4.59	4.59	4.67	4.67	9.31	2020
GAS						
$10,000,000 Revenues						
Columbia Gas of PA, Inc.*					Settled	2024
Peoples Natural Gas Company LLC	7.14	6.31	9.78	8.84	Settled	2024
PECO Energy - Gas Operations	6.06	4.93	7.49	5.56	Settled	2024
National Fuel Gas Distribution Co.	10.04	7.11	13.98	8.62	Settled	2023
UGI Utilities, Inc. – Gas Division*					Settled	2022
Valley Energy Inc. of PA	3.89	3.97	3.40	3.51	Settled	2022
$1,000,000 to $10,000,000						
Revenues						
Pike County Light & Power Co.	2.39	2.39	-1.16	-1.16	Settled	2021
Leatherstocking Gas Company	2.15	2.15	-3.47	-3.47	Settled	2023
North East Heat and Light Company	4.25	4.25	4.35	4.37	11.00	2008
WATER						
$10,000,000 Revenues						
PA American Water Company	7.08	6.70	9.12	8.44	9.45	2024
Aqua Pennsylvania	7.03	6.92	9.40	9.29	Settled	2025
York Water Company	7.30	6.00	9.48	7.10	Settled	2023
Veolia Water Pennsylvania, Inc.	5.90	4.94	7.21	5.36	Settled	2024
$1,000,000 to $10,000,000						
Revenues						
Newtown Artesian Water Co.	5.56	3.35	6.29	2.52	Settled	2025
Columbia Water Company	6.27	6.27	6.86	6.86	9.75	2024
York Water Company – Wastewater	1.30	0.40	-0.30	-2.10	Settled	2023
Community Utilities – Water	2.56	2.56	0.44	0.44	Settled	2022
Community Utilities – Wastewater	4.12	4.12	3.24	3.24	Settled	2022
CAN DO Inc. – Water	1.99	1.99	2.46	2.46	Settled	2024
CAN DO Inc. – Wastewater	22.76	22.76	25.93	25.93	Settled	2024

*Columbia Gas of PA Inc., UGI Utilities, Inc. – Gas Division, and FirstEnergy Pennsylvania Electric Co. have rate filings at Docket Nos. R-2025-3053499, R-2024-3052716, and R-2024-3047068, respectively, and have filed a letter with the Secretary in place of a report in accordance with 52 Pa. Code § 71.4.

ALLOWED RATES OF RETURN ON COMMON EQUITY

This is a historical chart that shows the most recent rate cases for select companies in electric, gas, and water. A docket number followed by their final return on equity and year is also given.

ELECTRIC	**Docket Number**	**ROE (%)**	**Year**
Recent PA PUC Allowed			
UGI Utilities, Inc. – Electric	R-2022-3037368	Settled	2023
Duquesne Light Company	R-2024-3046523	Settled	2024
PECO Energy – Electric	R-2024-3046931	Settled	2024
PPL Electric Utilities Corp.	R-2015-2469275	Settled	2015
Pennsylvania Electric Company	R-2024-3047068	Settled	2024
Metropolitan Edison Company	R-2024-3047068	Settled	2024
Pennsylvania Power Company	R-2024-3047068	Settled	2024
West Penn Power Company	R-2024-3047068	Settled	2024
Current Market Indicated ROE as calculated by the Bureau of Technical Utility Services.			**9.17-11.23**

GAS			
Recent PA PUC Allowed			
National Fuel Gas Distribution Corp.	R-2022-3035730	Settled	2023
Columbia Gas of Pennsylvania, Inc.	R-2024-3046519	Settled	2024
PECO Energy – Gas	R-2024-3046932	Settled	2024
UGI Utilities, Inc. – Gas	R-2021-3030218	Settled	2022
Peoples Natural Gas Company	R-2023-3044549	Settled	2024
Current Market Indicated ROE as calculated by the Bureau of Technical Utility Services.			**8.92-12.05**

WATER			
Recent PA PUC Allowed			
Columbia Water	R-2023-3040258	9.75	2024
PA American Water	R-2023-3043189	9.45	2024
York Water	R-2022-3031340	Settled	2023
Aqua Pennsylvania	R-2024-3047822	Settled	2025
Veolia Water Pennsylvania	R-2024-3045192	Settled	2024
Current Market Indicated ROE as calculated by the Bureau of Technical Utility Services.			**7.25-12.59**

Distribution System Improvement Charge (DSIC) Eligible Utilities
Return on Equity (ROE) Summary

	Utility Adjusted ROE[3] (%)	Commission Approved ROE[4] (%)
ELECTRIC		
PECO Energy – Electric Operations	4.22	10.00
PPL Electric Utilities Corp.	7.23	10.00
Duquesne Light Company	9.38	10.00
West Penn Power Company*		10.00
Pennsylvania Power Company*		10.00
Pennsylvania Electric Company*		10.00
Metropolitan Edison Company*		10.00
UGI Utilities, Inc.- Electric Division	1.41	10.00
Pike County Light & Power Co.	5.98	10.00
GAS		
Columbia Gas of PA, Inc.*		10.15
Peoples Natural Gas Company LLC	8.84	10.15
PECO Energy – Gas Operations	5.56	10.15
UGI Utilities, Inc. – Gas Division*		10.15
Pike County Light & Power Co.	-1.16	10.15
National Fuel Gas Distribution Corp	8.62	10.15
WATER		
PA American Water Company	8.44	9.45
PA American – Wastewater	8.44	9.45
AQUA Pennsylvania	9.29	9.75
AQUA Pennsylvania – Wastewater	9.29	9.75
York Water Company	7.10	9.75
Veolia Water Pennsylvania, Inc.	5.36	9.75
Columbia Water Company	6.86	9.75
Newtown Artesian Water	2.52	9.75

* Columbia Gas of PA Inc., UGI Utilities, Inc. – Gas Division, and FirstEnergy Pennsylvania Electric Co. have rate filings at Docket Nos. R-2025-3053499, R-2024-3052716, and R-2024-3047068, respectively, and have filed a letter with the Secretary in place of a report in accordance with 52 Pa. Code § 71.4.

3 Each utility lists adjustments on Schedule B of their quarterly financial report.
4 The ROE is approved in a utility's most recent fully litigated base rate proceeding for hich a final order was entered not more than two years prior to the effective date of the DSIC. If more than two years have elapsed between the entry of a final order and the DSIC effective date, the ROE is from this report. If the base rate proceeding is settled, without a stipulated ROE, the ROE is from this report.

Explanation of Discounted Cash Flow (DCF) and Capital Asset Pricing Model (CAPM)

Barometer Group Criteria

The criteria used for determining the industry barometer groups used to calculate ROEs in this report are as follows:

- 50% or more of the company's assets must be related to the jurisdictional utility industry;
- The company's stock must be publicly traded and must have at least three years of earnings history;
- Companies targeted by merger and acquisition (M&A) activity will be excluded; companies involved in M&A activity may be excluded;
- Investment information for the company must be available to the Commission from more than one source;
- The barometer group companies must have an investment grade credit rating (S&P BBB- or better, Moody's Baa3 or better); and
- Geographic Regions:
  EDCs: *Value Line* Investment Survey's East, Central, and West Group Electric Utility companies;
  NGDCs: *Value Line* Investment Survey's Natural Gas Utility industry group companies;
  Water/Wastewater: *Value Line* Investment Survey's Water Utility industry group companies.

The barometer group companies are reviewed by staff on a quarterly basis and make any changes to these companies based upon the criteria above.

ROE Calculations

The Commission consistently uses the DCF model to determine the appropriate cost of equity for utilities. In this report, the DSIC ROE is calculated using two DCF models.

TUS uses the following formula to calculate the current dividend DCF: $K = D_1/P_0 + G$

TUS uses the following formula to calculate the 52-week average dividend DCF: $K = D_0/P_a + G$

Definitions:

K	=	Cost of equity
D_1	=	Dividend expected during the year
	=	$D_0 + ½g$
D_0	=	Latest indicated dividend, obtained from Yahoo! Finance
g	=	Expected 5-year dividend growth rate of barometer group obtained from Value Line Investment Survey.
P_0	=	Current price of the stock, obtained from Yahoo! Finance
P_a	=	Average of high and low stock price over the latest 52-week period, obtained from Yahoo! Finance
G	=	Average of 5-year expected earnings growth rate forecasts obtained from Value Line, Zacks Investment Survey, and S&P Capital IQ.

The CAPM uses the yield of a risk-free interest-bearing obligation plus a rate of return premium that is proportional to the systematic risk of an investment.

TUS uses the following formula to calculate CAPM: $K = R_f + \beta(R_m - R_f)$

Three components are necessary to calculate the CAPM cost of equity:

β	=	Beta, a measure of systematic risk for each stock
R_f	=	The risk-free rate of return, 10-year U.S. Treasury yields are used for R_f. Yields are taken from the previous two quarters and forecasted next four quarters.
R_m	=	Total return of the equity market as determined by Kroll

The Commission determines the ROE used for DSIC purposes based on the range of reasonableness from the DCF barometer group data, CAPM data, recent ROE adjudicated by the Commission, and informed judgment.

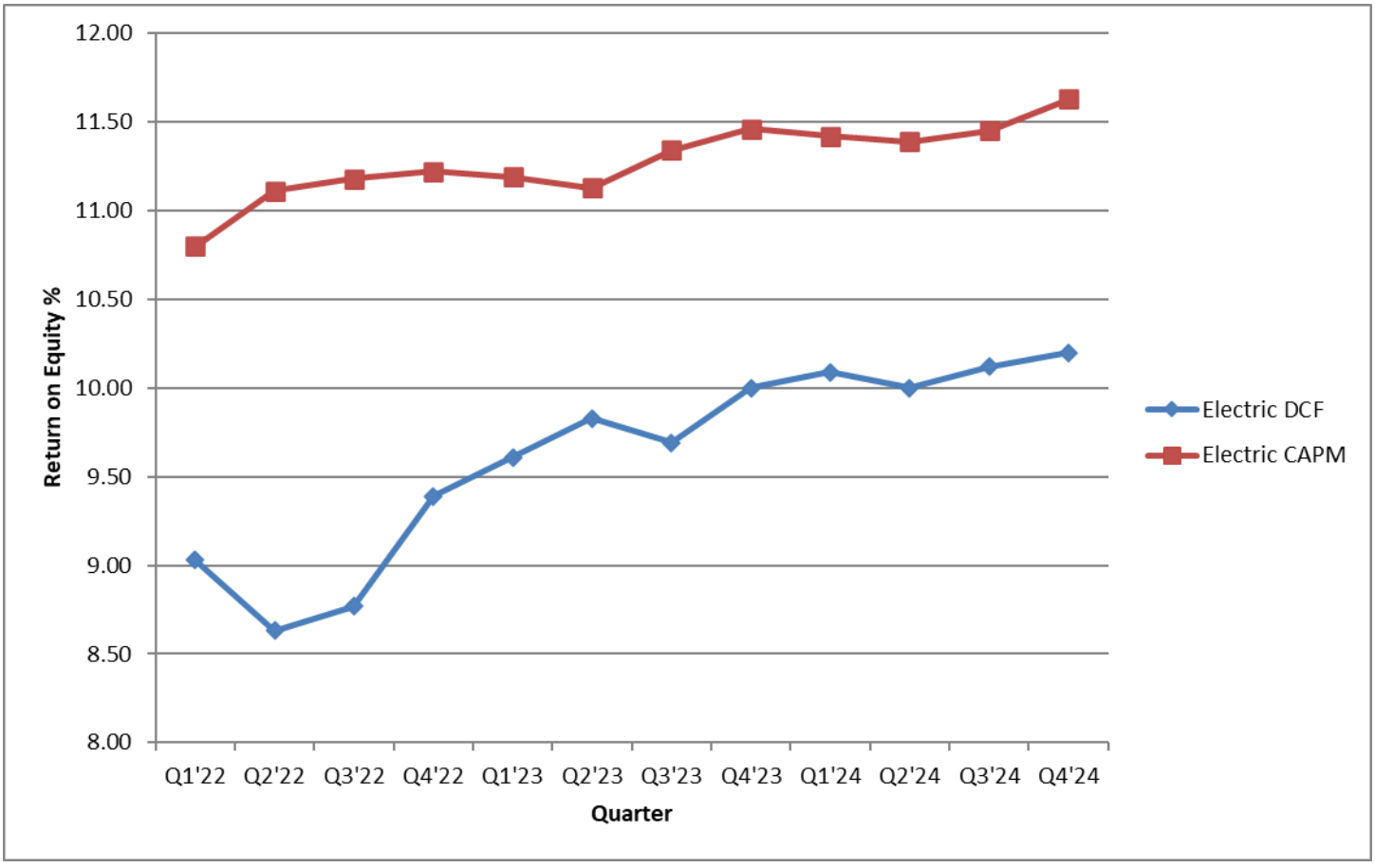
The market indicated common equity cost rate range consists of data used from the barometer groups and is based on a series of calculations to average the DCF methods.

Market Based Returns on Common Equity[1]	
April 7, 2025	
Electric Company Barometer Group	
	Cost Rates
	%
(1) Current DCF:	10.23
(2) 52-Week Average DCF:	10.18
(3) Overall DCF ((1) + (2)) / 2 :	10.20
(4) Market Indicated Common Equity Cost Rate Range:	9.17-11.23
(5) CAPM Check of DCF Reasonableness:	11.63
(6) Recent Commission Approved ROEs[3]:	*
*None within the last two years	
(7) Distribution System Improvement Charge (DSIC) Return[4]:	**10.00%**
[1] As calculated by the Bureau of Technical Utility Services	
[2] Standard Deviation of 58 DCF observations	
[3] Base rate case ROEs within last two years, fully litigated or stipulated for DSIC purposes	
[4] Commission authorized Return on Equity (ROE) for DSIC purposes	
Any questions concerning DSIC should be directed to Rich Layton	
of the Bureau of Technical Utility Services at (717) 214-9117.	

Historic Electric Industry Barometer Group DCF and CAPM Average ROEs

Electric		
	DCF	CAPM
Q1'22	9.03	10.80
Q2'22	8.63	11.11
Q3'22	8.77	11.18
Q4'22	9.39	11.22
Q1'23	9.61	11.19
Q2'23	9.83	11.13
Q3'23	9.69	11.34
Q4'23	10.00	11.46
Q1'24	10.09	11.42
Q2'24	10.00	11.39
Q3'24	10.12	11.45
Q4'24	10.20	11.63

Chart of Historic Electric Industry DCF and CAPM Average ROEs



Barometer electric companies are used to calculate a current DCF in the first chart. The second chart demonstrates the companies' 52-week average DCF. A final average of the two calculations is also shown at the bottom.

Electric Company Barometer Group
Calculation of a Current Dividend Yield

	Closing Market Price (Po) 4/7/2025 ($)	Latest Indicated Dividend (Do) ($)	Ind. Div. Plus 1/2 Div. Growth Rate (D1) ($)	Current Dividend Yield(D1/Po) (%)	DCF (%)
Alliant Energy Corp	59.81	2.03	2.09	3.50	10.00
Ameren Corp	94.34	2.84	2.93	3.11	9.80
American Electric Power	101.57	3.72	3.82	3.76	10.26
Avista Corp	39.56	1.96	2.00	5.05	10.71
CenterPoint Energy	35.50	0.88	0.91	2.55	9.88
CMS Energy Corp	70.94	2.17	2.22	3.14	10.13
Consolidated Edison	105.40	3.40	3.47	3.29	9.13
Dominion Energy	50.83	2.67	2.68	5.27	8.77
DTE Energy Company	127.95	4.36	4.46	3.48	11.47
Duke Energy Company	116.86	4.18	4.25	3.64	9.85
Edison International	53.62	3.31	3.41	6.36	13.94
Entergy Corp.	79.34	2.40	2.47	3.11	12.30
Evergy Inc	64.36	2.67	2.76	4.29	10.60
Eversource Energy	55.56	3.01	3.10	5.58	11.16
Exelon Corporation	44.69	1.60	1.60	3.58	9.63
FirstEnergy Corp	38.71	1.78	1.83	4.72	10.89
IDACORP, Inc..	113.75	3.44	3.53	3.11	10.71
MGE Energy, Inc.	87.02	1.80	1.86	2.14	9.14
NextEra Energy, Inc.	65.06	2.27	2.38	3.65	11.46
NorthWestern Corp	54.72	2.64	2.66	4.86	10.37
OGE Energy Corp	42.24	1.69	1.72	4.06	10.23
Otter Tail Corp	75.27	2.10	2.17	2.89	9.24
PPL Corporation	33.52	1.09	1.09	3.24	10.42
TXNM Energy Inc.	49.78	1.63	1.67	3.36	8.64
Pinnacle West Capital Corp	89.62	3.58	3.61	4.02	8.92
Portland General Electric Co.	41.58	2.00	2.06	4.94	9.91
Public Service Enterprise Group	77.13	2.52	2.60	3.37	9.95
Southern Company	87.22	2.88	2.93	3.36	9.80
Xcel Energy Inc.	67.06	2.28	2.35	3.50	10.49
Group Average	69.76	2.51	2.57	3.83	10.27
Group Average G				6.40	
DCF				**10.23**	

Electric Company Barometer Group 52-week Average Dividend Yield Calculation						
	High	Low	Average (Pa)	Latest Indicated Dividend (Do)	Average Dividend Yield (Do/Pa)	DCF
	($)	($)	($)	($)	(%)	(%)
Alliant Energy Corp	66.54	47.23	56.89	2.03	3.57	10.07
Ameren Corp	104.10	69.39	86.75	2.84	3.27	9.97
American Electric Power	110.48	79.16	94.82	3.72	3.92	10.42
Avista Corp	43.09	33.00	38.05	1.96	5.15	10.81
CenterPoint Energy	37.70	25.41	31.56	0.88	2.79	10.12
CMS Energy Corp	76.45	56.61	66.53	2.17	3.26	10.25
Consolidated Edison	114.87	87.28	101.08	3.40	3.36	9.20
Dominion Energy	61.97	46.62	54.30	2.67	4.92	8.42
DTE Energy Company	140.39	103.06	121.73	4.36	3.58	11.57
Duke Energy Company	125.27	92.75	109.01	4.18	3.83	10.04
Edison International	88.77	49.06	68.92	3.31	4.80	12.38
Entergy Corp.	88.38	50.19	69.29	2.40	3.46	12.65
Evergy Inc	70.30	49.55	59.93	2.67	4.46	10.76
Eversource Energy	69.01	54.54	61.78	3.01	4.87	10.45
Exelon Corporation	48.11	34.01	41.06	1.60	3.90	9.94
FirstEnergy Corp	44.97	36.81	40.89	1.78	4.35	10.52
IDACORP, Inc..	120.84	88.70	104.77	3.44	3.28	10.89
MGE Energy, Inc.	109.22	72.27	90.75	1.80	1.98	8.98
NextEra Energy, Inc.	86.10	61.31	73.71	2.27	3.08	10.88
NorthWestern Corp	59.52	47.48	53.50	2.64	4.93	10.45
OGE Energy Corp	46.91	32.37	39.64	1.69	4.26	10.44
Otter Tail Corp	100.84	71.66	86.25	2.10	2.43	8.78
PPL Corporation	36.64	25.93	31.29	1.09	3.48	10.66
TXNM Energy Inc.	55.50	35.35	45.43	1.63	3.59	8.86
Pinnacle West Capital Corp	96.50	70.72	83.61	3.58	4.28	9.18
Portland General Electric Co.	49.85	40.05	44.95	2.00	4.45	9.42
Public Service Enterprise Group	95.22	64.03	79.63	2.52	3.16	9.75
Southern Company	94.45	67.53	80.99	2.88	3.56	10.00
Xcel Energy Inc.	73.38	51.97	62.68	2.28	3.64	10.62
Group Average	79.84	56.69	68.27	2.51	3.78	10.22
Group Average G					6.40	
DCF					**10.18**	
		Average of Current and 52-Week			**10.20**	

Multiple sources of the Barometer companies' projected 5-year Earnings Per Share are used to calculate the Group Average Dividend Growth Estimate.

Development of a Representative Dividend Growth Rate
for the Barometer Group of Electric Companies

		5 Year Forecast				
	Value Line DPS (%)	Value Line EPS (%)	Zack's EPS (%)	S&P EPS (%)	Average Earnings Growth (%)	Growth Estimate (%)
Alliant Energy Corp	6.00	6.00	6.70	6.81	6.50	6.50
Ameren Corp	6.50	6.50	6.70	6.88	6.69	6.69
American Electric Power	5.50	6.50	6.30	6.69	6.50	6.50
Avista Corp	4.00	5.00	6.10	5.88	5.66	5.66
CenterPoint Energy	6.00	6.50	7.50	7.98	7.33	7.33
CMS Energy Corp	5.00	6.00	7.70	7.27	6.99	6.99
Consolidated Edison	4.00	6.00	5.60	5.91	5.84	5.84
Dominion Energy	0.50	3.50	13.60	13.49	10.20	3.50
DTE Energy Company	4.50	8.50	7.60	7.87	7.99	7.99
Duke Energy Company	3.50	6.00	6.30	6.32	6.21	6.21
Edison International	6.00	6.50	8.50	7.74	7.58	7.58
Entergy Corp.	5.50	3.00	9.50	8.88	7.13	9.19
Evergy Inc	7.00	7.50	5.70	5.72	6.31	6.31
Eversource Energy	6.00	5.50	5.70	5.54	5.58	5.58
Exelon Corporation	NA	NA	6.00	6.09	6.05	6.05
FirstEnergy Corp	5.50	5.50	6.90	6.11	6.17	6.17
IDACORP, Inc..	5.50	6.00	8.50	8.31	7.60	7.60
MGE Energy, Inc.	6.50	7.00	NA	NA	7.00	7.00
NextEra Energy, Inc.	9.50	8.50	7.80	7.11	7.80	7.80
NorthWestern Corp	1.50	4.50	6.10	5.94	5.51	5.51
OGE Energy Corp	3.00	6.50	6.10	5.92	6.17	6.17
Otter Tail Corp	7.00	4.50	NA	8.20	6.35	6.35
PPL Corporation	-0.50	7.50	6.80	7.22	7.17	7.17
TXNM Energy Inc.	5.50	4.00	3.00	6.55	4.52	5.28
Pinnacle West Capital Corp	1.50	4.00	2.10	5.80	3.97	4.90
Portland General Electric Co.	5.50	5.50	3.40	6.01	4.97	4.97
Public Service Enterprise Group	6.00	6.00	7.20	6.56	6.59	6.59
Southern Company	3.50	6.50	6.50	6.33	6.44	6.44
Xcel Energy Inc.	6.00	6.50	6.90	7.56	6.99	6.99
Group Average	4.86	5.91	6.70	7.02	6.54	6.44
USE						**6.40**

Sources: Value Line, April 8, 2025 (www.valueline.com)
Zacks, April 8, 2025 (www.zacks.com)
Yahoo!, April 8, 2025 (http://finance.yahoo.com/)
S&P Capital IQ, April 8, 2025 (www.spglobal.com)
* NA signifies that a forecast was not available

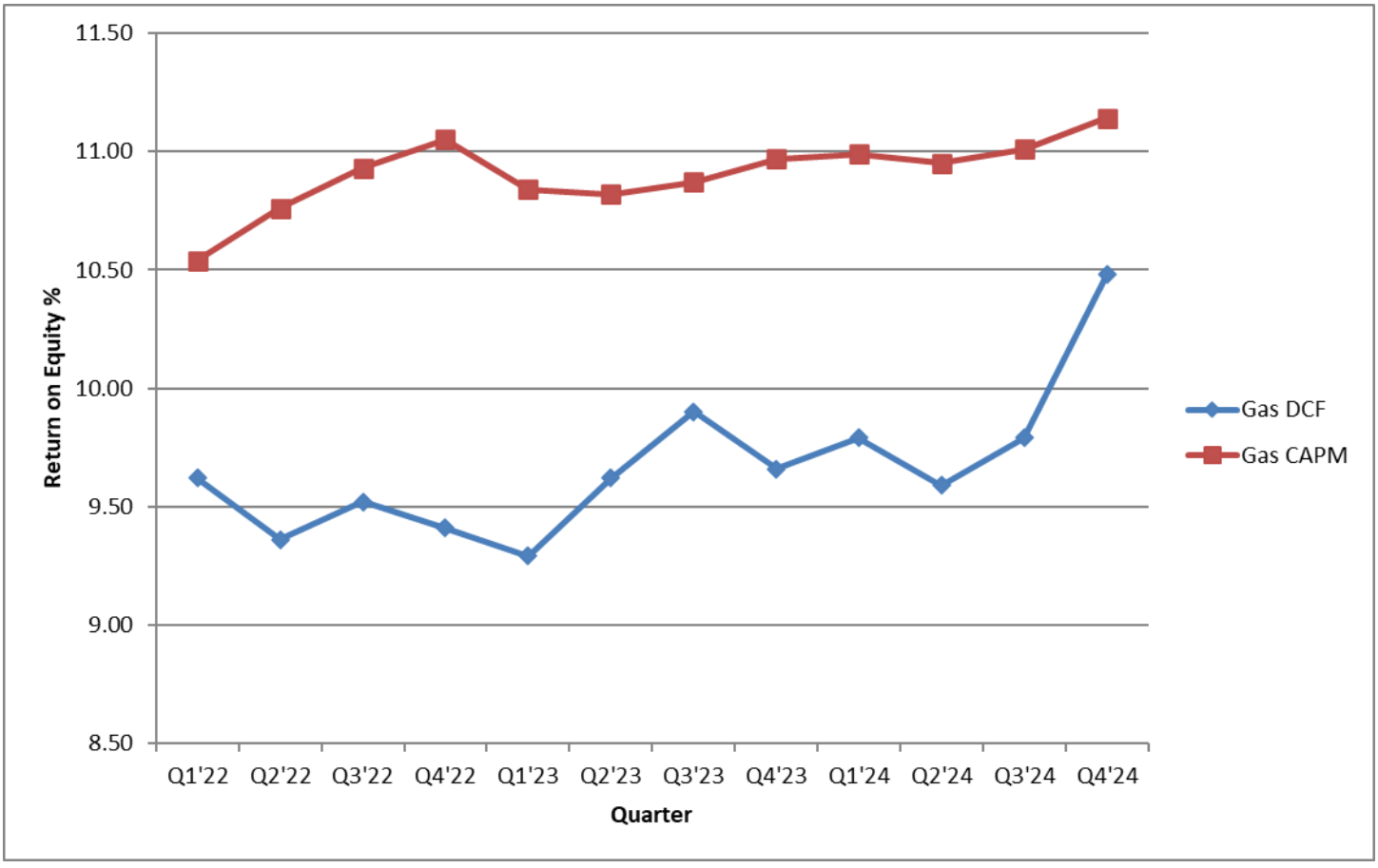
The market indicated common equity cost rate range consists of data used from the barometer groups and is based on a series of calculations to average the DCF methods.

Market Based Returns on Common Equity[1]	
April 7, 2025	
Gas Distribution Company Barometer Group	
	Cost Rates
	%
(1) Current DCF:	10.46
(2) 52-Week Average DCF:	10.51
(3) Overall DCF ((1) + (2)) / 2 :	10.48
(4) Market Indicated Common Equity Cost Rate Range:	8.92-12.05
@ 1 standard deviation around the mean.[2]	
(5) CAPM Check of DCF Reasonableness:	11.14
(6) Recent Commission Approved ROEs[3]:	*
*None within the last two years	
(7) Distribution System Improvement Charge (DSIC) Return[4]:	**10.15%**
[1] As calculated by the Bureau of Technical Utility Services	
[2] Standard Deviation of 16 DCF observations	
[3] Base rate case ROEs within last two years, fully litigated or stipulated for DSIC	
[4] Commission authorized Return on Equity (ROE) for DSIC purposes	
Any questions concerning DSIC should be directed to Rich Layton	
of the Bureau of Technical Utility Services at (717) 214-9117.	

Historic Gas Industry DCF and CAPM Average ROEs

Gas		
	DCF	CAPM
Q1'22	9.62	10.54
Q2'22	9.36	10.76
Q3'22	9.52	10.93
Q4'22	9.41	11.05
Q1'23	9.29	10.84
Q2'23	9.62	10.82
Q3'23	9.90	10.87
Q4'23	9.66	10.97
Q1'24	9.79	10.99
Q2'24	9.59	10.95
Q3'24	9.79	11.01
Q4'24	10.48	11.14

Graph of Historic Gas Industry DCF and CAPM Average ROEs



Barometer gas companies are used to calculate a current DCF in the first chart. The second chart demonstrates the companies' 52-week average DCF. A final average of the two calculations is also shown at the bottom.

Gas Company Barometer Group
Calculation of a Current Dividend Yield

	Closing Market Price (Po) 4/7/2025 ($)	Latest Indicated Dividend (Do) ($)	Ind. Div. Plus 1/2 Div. Growth Rate (D1) ($)	Current Dividend Yield(D1/Po) (%)	DCF (%)
Atmos Energy	145.06	3.48	3.60	2.48	9.39
Chesapeake Utilities Corporation	126.28	2.56	2.66	2.10	8.68
New Jersey Resources	46.94	1.80	1.85	3.93	10.23
NiSource Inc.	37.16	1.12	1.16	3.11	11.06
Northwest Natural Gas	40.06	1.96	1.96	4.90	11.40
ONE Gas, Inc.	71.91	2.68	2.71	3.77	8.35
Southwest Gas	66.91	2.48	2.55	3.81	13.56
Spire Inc.	73.73	3.14	3.20	4.34	10.70
Group Average	76.01	2.40	2.46	3.56	10.42
Group Average G				6.90	
DCF				**10.46**	

Gas Company Barometer Group
52-week Average Dividend Yield Calculation

	High ($)	Low ($)	Average (Pa) ($)	Latest Indicated Dividend (Do) ($)	Average Dividend Yield (Do/Pa) (%)	DCF (%)
Atmos Energy	157.62	110.97	134.30	3.48	2.59	9.50
Chesapeake Utilities Corporation	134.86	98.32	116.59	2.56	2.20	8.77
New Jersey Resources	51.95	40.62	46.29	1.80	3.89	10.19
NiSource Inc.	41.45	26.26	33.86	1.12	3.31	11.25
Northwest Natural Gas	44.25	34.82	39.54	1.96	4.96	11.46
ONE Gas, Inc.	78.89	58.31	68.60	2.68	3.91	8.48
Southwest Gas	80.29	64.31	72.30	2.48	3.43	13.18
Spire Inc.	79.81	57.27	68.54	3.14	4.58	10.94
Group Average	83.64	61.36	72.50	2.40	3.61	10.47
Group Average G					6.90	
DCF					**10.51**	
		Average of Current and 52-Week			**10.48**	

Multiple sources of the Barometer companies' projected 5-year Earnings Per Share are used to calculate the Group Average Dividend Growth Estimate.

Development of a Representative Dividend Growth Rate for the Barometer Group of Gas Companies						
	5 Yr Forecast					
	Value Line DPS (%)	Value Line EPS (%)	Zack's EPS (%)	S&P EPS (%)	Average Earnings Growth (%)	Growth Estimate (%)
Atmos Energy	7.00	6.00	7.20	7.52	6.91	6.91
Chesapeake Utilities Corporation	7.50	5.00	NA	8.15	6.58	6.58
New Jersey Resources	5.00	5.00	NA	7.60	6.30	6.30
NiSource Inc.	6.50	8.00	7.90	7.94	7.95	7.95
Northwest Natural Gas	0.50	6.50	NA	6.50	6.50	6.50
ONE Gas, Inc.	2.50	4.00	5.90	3.83	4.58	4.58
Southwest Gas	5.50	10.00	9.50	12.60	10.70	9.75
Spire Inc.	4.00	4.50	6.50	8.08	6.36	6.36
Group Average	4.81	6.13	7.40	7.78	6.98	6.86
USE						**6.90**
Sources:	Value Line, April 8, 2025 (www.valueline.com)					
	Zacks, April 8, 2025 (www.zacks.com)					
	Yahoo!, April 8, 2025 (http://finance.yahoo.com/)					
	S&P Capital IQ, April 8, 2025 (www.spglobal.com)					
	* NA signifies that a forecast was not available					

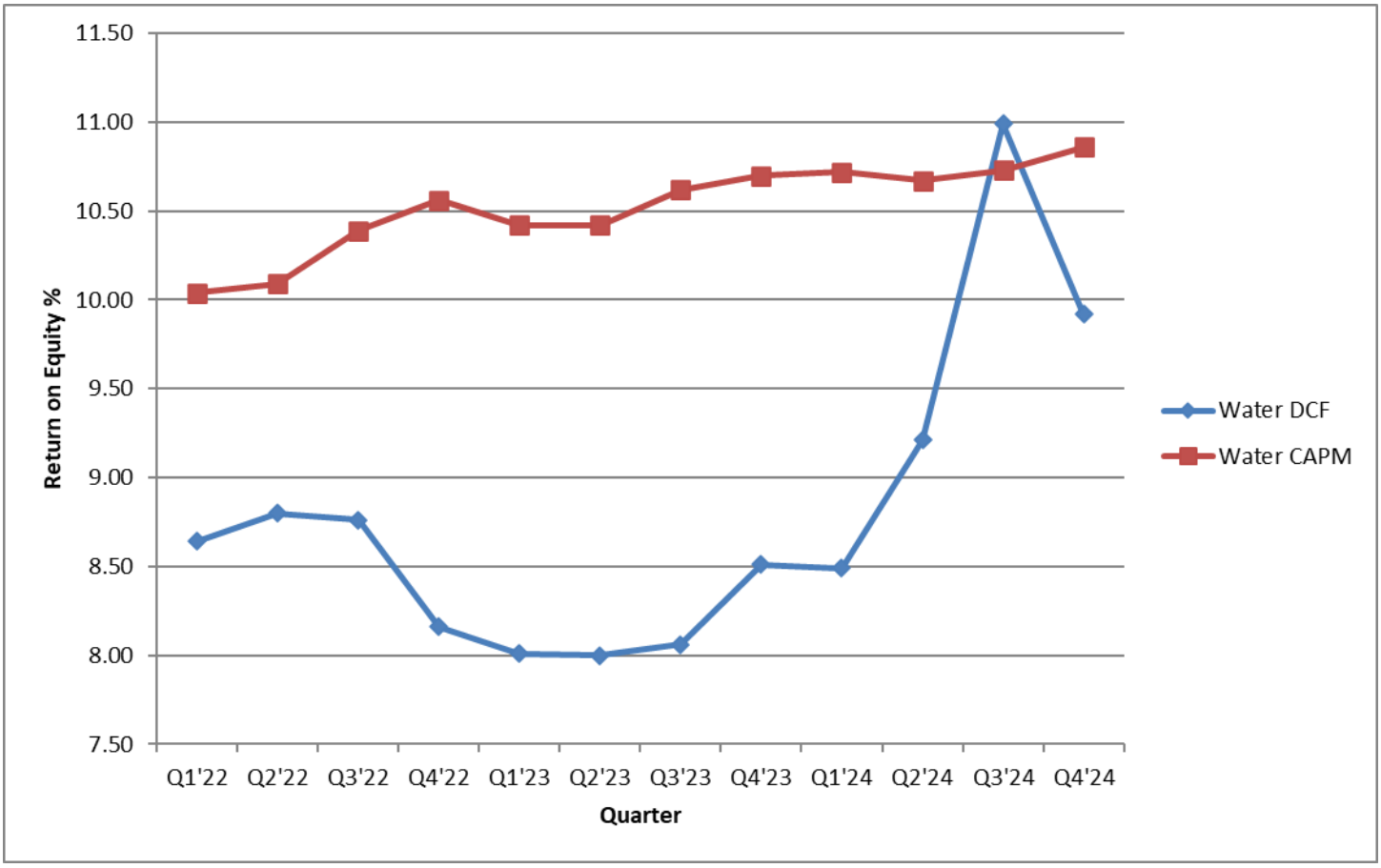
The market indicated common equity cost rate range consists of data used from the barometer groups and is based on a series of calculations to average the DCF methods.

Market Based Returns on Common Equity [1]	
April 7, 2025	
Water Company Barometer Group	
	Cost Rates %
(1) Current DCF	9.96
(2) 52-Week Average DCF	9.88
(3) Average DCF	9.92
(4) Market Indicated Common Equity Cost Rate Range @ 1 standard deviation around the mean.[2]	7.25-12.59
(5) CAPM Check of DCF Reasonableness	10.86
(6) Recent Commission Approved ROEs[3]:	
Columbia Water Company, R-2023-3040258	9.75
Pennsylvania-American water Company, R-2023-3043189	9.45
(7) Distribution System Improvement Charge (DSIC) Return[4]:	**9.75%**
[1] As calculated by the Bureau of Technical Utility Services	
[2] Standard Deviation of 12 DCF observations	
[3] ROEs from base rate cases within last two years, fully litigated or stipulated for DSIC purposes	
[4] Commission authorized Return on Equity (ROE) for DSIC purposes	
Any questions concerning DSIC should be directed to Rich Layton	
of the Bureau of Technical Utility Services at (717) 214-9117.	

Historic Water Industry DCF and CAPM Average ROEs

Water		
	DCF	CAPM
Q1'22	8.64	10.04
Q2'22	8.80	10.09
Q3'22	8.76	10.39
Q4'22	8.16	10.56
Q1'23	8.01	10.42
Q2'23	8.00	10.42
Q3'23	8.06	10.62
Q4'23	8.51	10.70
Q1'24	8.49	10.72
Q2'24	9.21	10.67
Q3'24	10.99	10.73
Q4'24	9.92	10.86

Chart of Historic Water Industry DCF and CAPM Average ROEs



Barometer water companies are used to calculate a current DCF in the first chart. The second chart demonstrates the companies' 52-week average DCF. A final average of the two calculations is also shown at the bottom.

Water Company Barometer Group
Calculation of a Current Dividend Yield

	Closing Market Price (Po) 4/7/2025	Latest Indicated Dividend (Do)	Ind. Div. Plus 1/2 Div. Growth Rate (D1)	Current Dividend Yield(D1/Po)	Growth	DCF
	($)	($)	($)	(%)	(%)	(%)
American States Water Company	75.41	1.86	1.93	2.57	3.52	6.08
American Water Works Co., Inc.	142.36	3.06	3.19	2.24	6.76	9.00
California Water Service Group	47.50	1.20	1.23	2.60	9.50	12.10
Essential Utilities, Inc.	38.32	1.30	1.35	3.53	6.70	10.23
Middlesex Water Company	61.62	1.36	1.39	2.26	11.65	13.92
SJW Group	51.28	1.68	1.72	3.35	5.17	8.52
Group Average	69.42	1.74	1.80	2.76	7.22	9.97
Group Average G				7.20		
DCF				**9.96**		

Water Company Barometer Group
52-week Average Dividend Yield Calculation

	High	Low	Average (Pa)	Latest Indicated Dividend (Do)	Average Dividend Yield (Do/Pa)	Growth	DCF
	($)	($)	($)	($)	(%)	(%)	(%)
American States Water Company	87.50	66.03	76.77	1.86	2.42	3.52	5.94
American Water Works Co., Inc.	155.50	113.34	134.42	3.06	2.28	6.76	9.03
California Water Service Group	56.25	41.64	48.95	1.20	2.45	9.50	11.95
Essential Utilities, Inc.	41.78	33.18	37.48	1.30	3.47	6.70	10.17
Middlesex Water Company	70.73	45.42	58.08	1.36	2.34	11.65	14.00
SJW Group	62.18	44.91	53.55	1.68	3.14	5.17	8.31
Group Average	78.99	57.42	68.21	1.74	2.68	7.22	9.90
Group Average G					7.20		
DCF					**9.88**		
		Average of Current and 52-Week			**9.92**		

Multiple sources of the Barometer companies' projected 5-year Earnings Per Share are used to calculate the Group Average Dividend Growth Estimate.

Development of a Representative Dividend Growth Rate
for the Barometer Group of Water Companies

	5 Yr Forecast					
					Average	
	Value Line	Value Line	Zacks	S&P	Earnings	Growth
	DPS	EPS	EPS	EPS	Growth	Estimate
	(%)	(%)	(%)	(%)	(%)	(%)
American States Water Company	8.00	7.00	1.80	1.75	3.52	3.52
American Water Works Co., Inc.	8.50	4.50	8.00	7.77	6.76	6.76
California Water Service Group	5.50	9.50	42.40	42.44	31.45	9.50
Essential Utilities, Inc.	8.00	7.00	6.60	6.51	6.70	6.70
Middlesex Water Company	5.00	7.00	14.00	13.96	11.65	11.65
SJW Group	4.50	6.50	4.50	4.52	5.17	5.17
Group Average	6.58	6.92	12.88	12.83	10.88	7.22
USE						**7.20**

Sources: Value Line, April 8, 2025 (www.valueline.com)
Zacks, April 8, 2025 (www.zacks.com)
Yahoo!, April 8, 2025 (http://finance.yahoo.com/)
S&P Capital IQ, April 8, 2025 (www.spglobal.com)
* NA signifies that a forecast was not available

EXHIBIT JBF-2

			Requested			Approved				
State	Company	Case identification	Date	Rate Change ($000)	Return on Equity (%)	Date	Rate Change ($000)	Return on Equity (%)	Case Type	Decision Type
MD	Potomac Electric Power Company	C-9702	5/16/2023	187,912	10.50	6/10/2024	44,629	9.50	Distribution	Fully Litigated
MA	Fitchburg Gas and Electric Light Company, Inc.	DPU 23-80	8/17/2023	5,142	10.50	6/28/2024	4,849	9.40	Distribution	Fully Litigated
NY	Central Hudson Gas & Electric Corporation	C-23-E-0418	7/31/2023	128,708	9.80	7/18/2024	74,418	9.50	Distribution	Fully Litigated
MA	Massachusetts Electric Company	DPU 23-150	11/16/2023	118,300	10.50	9/30/2024	90,157	9.35	Distribution	Fully Litigated
DC	Potomac Electric Power Company	FC-1176	4/13/2023	186,488	10.50	11/25/2024	123,351	9.50	Distribution	Fully Litigated
ME	Versant Power	D-2023-00336	3/1/2024	36,144	9.35	3/13/2025	32,300	9.35	Distribution	Fully Litigated
TX	AEP Texas Inc.	D-56165	2/29/2024	100,387	10.60	10/3/2024	45,499	9.76	Distribution	Settled
NJ	Public Service Electric and Gas Company	D-ER23120924	12/29/2023	560,915	10.40	10/9/2024	440,500	9.60	Distribution	Settled
TX	CenterPoint Energy Houston Electric, LLC	D-56211	3/6/2024	14,584	10.40	3/13/2025	-33,543	9.65	Distribution	Settled
NY	Orange and Rockland Utilities, Inc.	C-24-E-0060	1/26/2024	10,678	10.25	3/20/2025	-13,060	9.75	Distribution	Settled
NH	Liberty Utilities (Granite State Electric) Corp.	D-DE-23-039	5/5/2023	20,155	10.35	3/25/2025	323	9.10	Distribution	Settled
MI	Indiana Michigan Power Company	C-U-21461	9/15/2023	41,113	10.50	7/2/2024	21,620	9.86	Vertically Integrated	Fully Litigated
VT	Green Mountain Power Corporation	C-24-1709-TF	5/31/2024	38,060	9.97	8/26/2024	38,060	9.97	Vertically Integrated	Fully Litigated
NV	Sierra Pacific Power Company	D-24-02026	2/23/2024	96,223	10.47	9/18/2024	40,315	9.74	Vertically Integrated	Fully Litigated
CA	San Diego Gas & Electric Company	A-22-04-012 (Phase 2)	1/16/2024	NA	10.65	10/17/2024	-24,900	10.23	Vertically Integrated	Fully Litigated
CA	Pacific Gas and Electric Company	A-22-04-008 (Phase 2)	1/16/2024	NA	10.70	10/17/2024	-114,900	10.28	Vertically Integrated	Fully Litigated
CA	Southern California Edison Company	A-22-04-009 (Phase 2)	1/16/2024	NA	10.75	10/17/2024	-104,400	10.33	Vertically Integrated	Fully Litigated
VA	Appalachian Power Company	C-PUR-2024-00024	3/29/2024	78,304	10.80	11/20/2024	9,768	9.75	Vertically Integrated	Fully Litigated
FL	Tampa Electric Company	D-20240026-EI	4/2/2024	295,522	11.50	12/3/2024	184,881	10.50	Vertically Integrated	Fully Litigated
OR	PacifiCorp	D-UE-433	2/14/2024	208,800	9.65	12/19/2024	139,653	9.50	Vertically Integrated	Fully Litigated
WI	Wisconsin Public Service Corporation	D-6690-UR-128 (Elec)	4/12/2024	172,349	10.00	12/19/2024	85,095	9.80	Vertically Integrated	Fully Litigated
WI	Wisconsin Electric Power Company	D-5-UR-111 (Elec)	4/12/2024	423,334	10.00	12/19/2024	313,507	9.80	Vertically Integrated	Fully Litigated
OR	Portland General Electric Company	D-UE-435	2/29/2024	249,900	9.50	12/20/2024	100,000	9.34	Vertically Integrated	Fully Litigated
WA	Avista Corporation	D-UE-240006	1/18/2024	112,156	10.40	12/20/2024	80,735	9.80	Vertically Integrated	Fully Litigated
WA	Puget Sound Energy, Inc.	D-UE-240004	2/15/2024	588,003	10.50	1/15/2025	529,915	9.90	Vertically Integrated	Fully Litigated
MI	DTE Electric Company	C-U-21534	3/28/2024	441,049	10.50	1/23/2025	217,380	9.90	Vertically Integrated	Fully Litigated
IN	Duke Energy Indiana, LLC	Ca-46038	4/4/2024	536,149	10.50	1/29/2025	295,678	9.75	Vertically Integrated	Fully Litigated
FL	Florida Public Utilities Company	D-20240099-EI	8/22/2024	12,593	11.30	3/4/2025	8,400	10.20	Vertically Integrated	Fully Litigated
CO	Black Hills Colorado Electric, Inc.	D-24AL-0275E	6/14/2024	25,144	9.83	3/12/2025	17,032	9.40	Vertically Integrated	Fully Litigated
MI	Consumers Energy Company	C-U-21585	5/31/2024	255,433	10.25	3/21/2025	153,809	9.90	Vertically Integrated	Fully Litigated
UT	PacifiCorp	D-24-035-04	6/28/2024	331,500	9.65	4/25/2025	87,233	9.38	Vertically Integrated	Fully Litigated
KY	Kentucky Power Company	C-2023-00159	6/29/2023	93,936	9.90	1/19/2024	60,032	9.75	Vertically Integrated	Settled
VA	Virginia Electric and Power Company	C-PUR-2023-00101	7/3/2023	104,605	9.70	2/28/2024	0	9.70	Vertically Integrated	Settled
WV	Monongahela Power Company	C-23-0460-E-42T	5/31/2023	172,788	10.85	3/26/2024	105,000	9.80	Vertically Integrated	Settled
IN	AES Indiana	Ca-45911	6/28/2023	134,242	10.60	4/17/2024	71,037	9.90	Vertically Integrated	Settled
IN	Indiana Michigan Power Company	Ca-45933	8/9/2023	116,376	10.50	5/8/2024	61,542	9.85	Vertically Integrated	Settled
SC	Duke Energy Carolinas, LLC	D-2023-388-E	1/4/2024	323,052	10.50	6/20/2024	233,847	9.94	Vertically Integrated	Settled
SC	Dominion Energy South Carolina, Inc.	D-2024-34-E	3/1/2024	302,894	10.60	8/8/2024	219,470	9.94	Vertically Integrated	Settled
FL	Duke Energy Florida, LLC	D-20240025-EI	4/2/2024	819,945	11.15	8/21/2024	470,000	10.30	Vertically Integrated	Settled
IA	Interstate Power and Light Company	D-RPU-2023-0002 (electric)	10/12/2023	457,934	10.11	9/17/2024	185,000	9.87	Vertically Integrated	Settled
OR	Idaho Power Company	D-UE-426	12/15/2023	10,695	10.40	9/23/2024	6,732	9.50	Vertically Integrated	Settled
MI	Upper Peninsula Power Company	C-U-21555	3/21/2024	16,914	10.70	9/26/2024	9,000	9.86	Vertically Integrated	Settled
MI	Upper Michigan Energy Resources Corporation	C-U-21541	5/1/2024	11,162	10.25	10/10/2024	6,600	9.86	Vertically Integrated	Settled
MN	Minnesota Power Enterprises, Inc.	D-E-015/GR-23-155	11/1/2023	127,853	10.30	10/24/2024	89,168	9.78	Vertically Integrated	Settled
OK	Oklahoma Gas and Electric Company	Ca-PUD2023-000087	12/29/2023	332,537	10.50	11/26/2024	126,660	9.50	Vertically Integrated	Settled
ND	Otter Tail Power Company	C-PU-23-342	11/2/2023	44,773	10.60	12/30/2024	36,444	10.10	Vertically Integrated	Settled
NC	Virginia Electric and Power Company	E-22, Sub 694	3/28/2024	60,863	10.60	1/14/2025	36,835	9.95	Vertically Integrated	Settled
OK	Public Service Company of Oklahoma	Ca-PUD2023-000086	1/31/2024	217,379	10.80	1/15/2025	119,500	9.50	Vertically Integrated	Settled
CA	Bear Valley Electric Service, Inc.	A-22-08-010	8/30/2022	17,520	11.25	1/16/2025	13,095	10.00	Vertically Integrated	Settled
IN	Southern Indiana Gas and Electric Company	Ca-45990	12/5/2023	118,758	10.40	2/3/2025	93,973	9.80	Vertically Integrated	Settled
NM	Public Service Company of New Mexico	C-24-00089-UT	6/14/2024	174,320	10.45	5/15/2025	105,000	9.45	Vertically Integrated	Settled
VA	Appalachian Power Company	C-PUR-2023-00102 (BC-RA	8/25/2023	7,022	9.50	2/20/2024	7,022	9.50	Limited-Issue Rider	Fully Litigated
VA	Virginia Electric and Power Company	C-PUR-2023-00094 (Rider C	6/1/2023	8,247	9.70	2/21/2024	4,965	9.70	Limited-Issue Rider	Fully Litigated
VA	Virginia Electric and Power Company	C-PUR-2023-00184 (Rider F	10/10/2023	10,104	9.70	3/22/2024	10,104	9.70	Limited-Issue Rider	Fully Litigated

			Requested			Approved				
State	Company	Case identification	Date	Rate Change ($000)	Return on Equity (%)	Date	Rate Change ($000)	Return on Equity (%)	Case Type	Decision Type
VA	Virginia Electric and Power Company	C-PUR-2023-00142 (Rider C	10/3/2023	47,522	9.70	3/29/2024	44,126	9.70	Limited-Issue Rider	Fully Litigated
VA	Virginia Electric and Power Company	C-PUR-2023-00137 (Rider U	8/1/2023	-3,731	9.70	4/29/2024	-3,731	9.70	Limited-Issue Rider	Fully Litigated
VA	Virginia Electric and Power Company	C-PUR-2023-00138 (Rider U	8/1/2023	-2,273	9.70	4/29/2024	-2,273	9.70	Limited-Issue Rider	Fully Litigated
VA	Virginia Electric and Power Company	C-PUR-2023-00136 (Rider C	8/1/2023	130,389	9.70	5/1/2024	130,389	9.70	Limited-Issue Rider	Fully Litigated
VA	Virginia Electric and Power Company	C-PUR-2023-00171 (Rider S	10/3/2023	45,145	9.70	7/3/2024	18,788	9.70	Limited-Issue Rider	Fully Litigated
VA	Virginia Electric and Power Company	C-PUR-2023-00172 (Rider U	10/3/2023	75,286	9.70	7/3/2024	75,286	9.70	Limited-Issue Rider	Fully Litigated
VA	Appalachian Power Company	C-PUR-2023-00169 (RAC-E	11/30/2023	14,956	9.20	7/26/2024	11,493	9.20	Limited-Issue Rider	Fully Litigated
VA	Virginia Electric and Power Company	C-PUR-2023-00195 (Rider C	11/1/2023	214,938	9.70	7/26/2024	214,937	9.70	Limited-Issue Rider	Fully Litigated
VA	Virginia Electric and Power Company	C-PUR-2023-00217 (Rider I	12/11/2023	-14,820	9.70	7/26/2024	-15,189	9.70	Limited-Issue Rider	Fully Litigated
VA	Virginia Electric and Power Company	C-PUR-2024-00013 (Rider E	1/24/2024	-37,077	9.70	9/19/2024	-37,077	9.70	Limited-Issue Rider	Fully Litigated
VA	Virginia Electric and Power Company	C-PUR-2024-00029 (Rider C	3/5/2024	-91,200	9.70	11/4/2024	-91,200	9.70	Limited-Issue Rider	Fully Litigated
VA	Virginia Electric and Power Company	C-PUR-2024-00097 (Rider C	6/4/2024	84,436	9.70	2/27/2025	55,655	9.70	Limited-Issue Rider	Fully Litigated
VA	Virginia Electric and Power Company	C-PUR-2024-00180 (Rider F	10/1/2024	6,967	9.70	3/26/2025	6,967	9.70	Limited-Issue Rider	Fully Litigated
VA	Virginia Electric and Power Company	C-PUR-2024-00147 (Rider C	10/16/2024	48,354	9.70	4/15/2025	48,260	9.70	Limited-Issue Rider	Fully Litigated
VA	Virginia Electric and Power Company	C-PUR-2024-00137 (Rider E	8/1/2024	-23,357	9.70	5/1/2025	-27,382	9.70	Limited-Issue Rider	Fully Litigated

Source: S&P Capital IQ (dated 6-25-2025)

EXHIBIT JBF-3

DIRECT TESTIMONY WORKPAPERS**

JBF WP-1 Wellsboro Electric Exhibit HSG-1**

JBF WP-2 Account 921**

JBF WP-3 Survey of Electric ROE**

The above referenced workpapers, JBF WP-1, JBF WP-2, and JBF WP-3 will be served electronically in excel format only, simultaneous to service of OSBA's Direct Testimony ONLY

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	**Docket No. R-2025-3054392**
v.	:	
	:	
Wellsboro Electric Company	:	

VERIFICATION

I, Justin B. Farr, hereby state that the facts set forth in my Direct Testimony, labelled OSBA Statement No. 1, and Exhibit JBF-1, Exhibit JBF-2, and Exhibit JBF-3, are true and correct to the best of my knowledge, information, and belief, and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements made herein are subject to the penalties of 18 Pa. C.S. § 4904 (relating to unsworn falsification to authorities).

Date: July 14, 2025

Justin B. Farr

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	**Docket No. R-2025-3054392**
v.	:	
	:	
Wellsboro Electric Company	:	

CERTIFICATE OF SERVICE

I hereby certify that true and correct copies of the foregoing have been served via email (*unless otherwise noted below*) upon the following persons, in accordance with the requirements of 52 Pa. Code § 1.54 (relating to service by a participant).

The Honorable Mary D. Long
Administrative Law Judge
Pennsylvania Public Utility Commission
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Date: July 15, 2025

/s/ Rebecca Lyttle
Rebecca Lyttle
Assistant Small Business Advocate
Attorney ID No. 201399

COMMONWEALTH OF PENNSYLVANIA

August 13, 2025

The Honorable Mary D. Long
Administrative Law Judge
Pennsylvania Public Utility Commission
Piatt Place
301 Fifth Avenue, Suite 220
Pittsburgh, PA 15222

Re: Pennsylvania Public Utility Commission v. Wellsboro Electric Company / Docket No. R-2025-3054392

Dear Judge Long:

Enclosed please find the Rebuttal Testimony of Justin B. Farr, labelled OSBA Statement No.1-R, on behalf of the Office of Small Business Advocate ("OSBA"), in the above-referenced proceeding.

As evidenced by the enclosed Certificate of Service, all known parties will be served, as indicated.

If you have any questions, please do not hesitate to contact me.

Sincerely,

/s/ Rebecca Lyttle

Rebecca Lyttle
Assistant Small Business Advocate
Attorney ID No. 201399

Enclosures
cc: PA PUC Secretary Matthew L. Homsher (Cover Letter & Certificate of Service only)
Kevin Higgins / Rebecca Forbes / Justin Farr
Joseph Kubas
Parties of Record

OSBA Statement No. 1-R

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	**:**	
	:	**Docket No. R-2025-3054392**
v.	**:**	
	:	
Wellsboro Electric Company	**:**	

Rebuttal Testimony

of

Justin B. Farr

on behalf of

Pennsylvania Office of Small Business Advocate

Topics:

Classification of Distribution Costs

Date Served: August 13, 2025

Date Submitted for the Record: _____

REBUTTAL TESTIMONY OF JUSTIN B. FARR

INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Justin B. Farr. My business address is 111 East Broadway, Suite 1200, Salt Lake City, Utah, 84111.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am a Director in the firm of Energy Strategies, LLC. Energy Strategies is a private consulting firm specializing in economic and policy analysis applicable to energy production, transportation, and consumption.

Q. ARE YOU THE SAME JUSTIN B. FARR WHO PREFILED DIRECT TESTIMONY IN THIS DOCKET ON BEHALF OF THE PENNSYLVANIA OFFICE OF SMALL BUSINESS ADVOCATE ("OSBA")?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR SURREBUTTAL TESTIMONY?

A. My rebuttal testimony responds to the direct testimony of Citizens' witness Howard Gorman and Pennsylvania Office of Consumer Advocate ("OCA") witness Michael Deupree.

RESPONSE TO CITIZENS

Q. DO YOU AGREE WITH WELLSBORO'S FILED COST OF SERVICE STUDY WITH RESPECT TO THE CLASSIFICATION OF SECONDARY DISTRIBUTION PLANT ACCOUNTS 364 THROUGH 368?

A. Yes. Wellsboro Electric Company ("Wellsboro" or "the company") proposes to classify distribution plant accounts 364 through 368 as partially demand-related, and partially customer-related. I agree with this approach. Wellsboro witness Mr. Gorman conducted a zero-load analysis to determine the customer-related component of secondary-voltage distribution system costs included in accounts 364-367, and a minimum size analysis to determine the customer-related component of costs in account 368.[1] Mr. Gorman's use of the zero-load analysis and minimum-size analysis to classify distribution plant assets as partially customer-related is supported by the National Association of Regulatory Utility Commissions ("NARUC").

RESPONSE TO OCA

Q. WHAT DOES OCA WITNESS MR. DEUPREE RECOMMEND REGARDING THE CLASSIFICATION OF DISTRIBUTION PLANT ACCOUNTS 364 THROUGH 367?

A. Mr. Deupree recommends that the Commission reject the Company's proposed use of zero-load analysis and minimum-size analysis, together referred to as the minimum system study ("MSS") approach, for classifying the costs of secondary-voltage distribution plant included in FERC accounts 364 through 368. He claims that both the minimum system and zero-intercept methods are fundamentally flawed, offer little to no value in setting just and reasonable rates, and have been discredited by research. He further notes that some state regulatory commissions

[1] Direct Testimony of Howard S. Gorman (Wellsboro Statement No. 1), page 20.

have expressly rejected the use of these methods. Instead, Mr. Deupree recommends that the Commission classify the assets in the relevant distribution plant accounts as 100 percent demand-related.[2]

Q. WHAT EVIDENCE DOES MR. DEUPREE PROVIDE TO SUPPORT HIS RECOMMENDATION?

A. Mr. Deupree cites a passage from the Electric Utility Cost Allocation Manual published by NARUC ("NARUC Manual") in support of his position. However, the NARUC Manual clearly states that Accounts 364 through 368 contain both customer-related and demand-related components. In addition, Mr. Deupree references two jurisdictions that have rejected the use of MSS analyses. He does not acknowledge the jurisdictions that use MSS analyses.

Q. IS YOUR POSITION CONSISTENT WITH THE RECOMMENDED TREATMENT OF THESE COSTS AS PRESENTED IN THE NARUC MANUAL?

A. Yes, it is. The NARUC Manual states that:

> Distribution Plant Accounts 364 through 370 involve demand and customer costs. **The customer component of distribution facilities is that portion of costs which varies with the number of customers. Thus, the number of poles, conductors, transformers, services, and meters are directly related to the number of customers on the utility's system**. As shown in Table 6-1, each primary plant account can be separately classified into a demand and customer component. Two methods are used to determine the demand and customer components of distribution facilities. They are, the minimum-size-of-facilities method, and the minimum-intercept cost (zero-intercept or positive-intercept cost, as applicable) of facilities.[3] (emphasis added).

[2] OCA Statement No. 3, Direct Testimony of Michael Deupree, pages 21-22.
[3] Electric Utility Cost Allocation Manual, January 1992, p. 90.

Table 6-1, referenced above, from the NARUC Manual is included below. Table 6-1 shows FERC Accounts 364-368 as having demand-related and customer-related components.

TABLE 6-1

CLASSIFICATION OF DISTRIBUTION PLANT[1]

FERC Uniform System of Accounts No.	Description	Demand Related	Customer Related
	Distribution Plant [2]		
360	Land & Land Rights	X	X
361	Structures & Improvements	X	X
362	Station Equipment	X	-
363	Storage Battery Equipment	X	-
364	Poles, Towers, & Fixtures	X	X
365	Overhead Conductors & Devices	X	X
366	Underground Conduit	X	X
367	Underground Conductors & Devices	X	X
368	Line Transformers	X	X
369	Services	-	X
370	Meters	-	X
371	Installations on Customer Premises	-	X
372	Leased Property on Customer Premises	-	X
373	Street Lighting & Signal Systems [1]	-	-

[1]Assignment or "exclusive use" costs are assigned directly to the customer class or group which exclusively uses such facilities. The remaining costs are then classified to the respective cost components.

[2]The amounts between classification may vary considerably. A study of the minimum intercept method or other appropriate methods should be made to determine the relationships between the demand and customer components.

Q. WHAT IS YOUR RESPONSE TO MR. DEUPREE'S RECOMMENDATION THAT COSTS ASSOCIATED WITH DISTRIBUTION PLANT ACCOUNTS

364 THROUGH 368 BE CLASSIFIED AND ALLOCATED ON ONLY A DEMAND BASIS?

A. I disagree with Mr. Deupree's recommendation. The costs associated with distribution plant accounts 364 through 368 include facilities such as poles and conductors, which have a significant customer-related component. These facilities are installed to deliver service to customer premises, and a substantial portion of the investment required is directly related to the number of customers and their geographic dispersion across the utility's service territory.

A well-designed and equitable distribution cost-of-service study should reflect these cost-causation factors. By contrast, Mr. Deupree's approach overlooks the influence of customer count and geographic layout on system investment needs. His proposal to classify all costs in these accounts as solely demand-related would under-assign cost responsibility to customers based on their number and location, while over-assigning costs based solely on demand. This would result in an unreasonable cost shift to larger customers served on the distribution system. I recommend that the Commission maintain the Company's proposed approach which correctly classifies distribution plant accounts 364 through 368 as partially demand-related, and partially customer-related.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	**Docket No. R-2025-3054392**
v.	:	
	:	
Wellsboro Electric Company	:	

VERIFICATION

I, Justin B. Farr, hereby state that the facts set forth in my Rebuttal Testimony, labelled OSBA Statement No. 1-R, are true and correct to the best of my knowledge, information, and belief, and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements made herein are subject to the penalties of 18 Pa. C.S. § 4904 (relating to unsworn falsification to authorities).

Date: August 11, 2025

Justin B. Farr

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	**Docket No. R-2025-3054392**
v.	:	
	:	
Wellsboro Electric Company	:	

CERTIFICATE OF SERVICE

I hereby certify that true and correct copies of the foregoing have been served via email (*unless otherwise noted below*) upon the following persons, in accordance with the requirements of 52 Pa. Code § 1.54 (relating to service by a participant).

The Honorable Mary D. Long
Administrative Law Judge
Pennsylvania Public Utility Commission
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Pittsburgh, PA 15222
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Date: August 13, 2025

/s/ Rebecca Lyttle
Rebecca Lyttle
Assistant Small Business Advocate
Attorney ID No. 201399

COMMONWEALTH OF PENNSYLVANIA

August 28, 2025

The Honorable Mary D. Long
Administrative Law Judge
Pennsylvania Public Utility Commission
Piatt Place
301 Fifth Avenue, Suite 220
Pittsburgh, PA 15222

Re: Pennsylvania Public Utility Commission v. Wellsboro Electric Company / Docket No. R-2025-3054392

Dear Judge Long:

Enclosed please find the Surrebuttal Testimony and Exhibit of Justin B. Farr labelled OSBA Statement No.1-SR, with associated Exhibit JBF-1SR, on behalf of the Office of Small Business Advocate ("OSBA"), in the above-referenced proceeding.

As evidenced by the enclosed Certificate of Service, all known parties will be served, as indicated.

If you have any questions, please do not hesitate to contact me.

Sincerely,

/s/ Rebecca Lyttle

Rebecca Lyttle
Assistant Small Business Advocate
Attorney ID No. 201399

Enclosures
cc: PA PUC Secretary Matthew L. Homsher (Cover Letter & Certificate of Service only)
Kevin Higgins / Rebecca Forbes / Justin Farr
Joseph Kubas
Parties of Record

OSBA Statement No. 1-SR

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	**:**	
	:	**Docket No. R-2025-3054392**
v.	**:**	
	:	
Wellsboro Electric Company	**:**	

Surrebuttal Testimony and Exhibit

of

Justin B. Farr

on behalf of

Pennsylvania Office of Small Business Advocate

Topics:

Revenue Requirement Adjustments

Date Served: August 28, 2025

Date Submitted for the Record: _____

SURREBUTTAL TESTIMONY OF JUSTIN B. FARR

INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Justin B. Farr. My business address is 111 East Broadway, Suite 1200, Salt Lake City, Utah, 84111.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am a Director in the firm of Energy Strategies, LLC. Energy Strategies is a private consulting firm specializing in economic and policy analysis applicable to energy production, transportation, and consumption.

Q. ARE YOU THE SAME JUSTIN B. FARR WHO PREFILED DIRECT TESTIMONY AND REBUTTAL TESTIMONY IN THIS DOCKET ON BEHALF OF THE PENNSYLVANIA OFFICE OF SMALL BUSINESS ADVOCATE ("OSBA")?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR SURREBUTTAL TESTIMONY?

A. My surrebuttal testimony responds to the rebuttal testimony of Wellsboro Electric Company ("Wellsboro" or "the Company") witness Dylan W. D'Ascendis, and Pennsylvania Office of Consumer Advocate ("OCA") witness Christopher C. Walters regarding my use of a 10% proxy return on equity ("ROE") in my revenue requirement calculations.

I also respond to Wellsboro witness Bryon Farnsworth, Jr. regarding the Performance Factor Adjustment.

Q. WHAT CONCLUSIONS DO YOU OFFER IN YOUR SURREBUTTAL TESTIMONY?

A. I offer the following conclusions:

1) I explain my use of a proxy ROE in my direct revenue requirement calculations and provide the results of my revenue requirement calculations using the costs of capital recommended by the Bureau of Investigation and Enforcement ("I&E") and OCA.
2) I continue to recommend eliminating the performance factor adjustment entirely and lowering or removing the size factor adjustment.

REVENUE REQUIREMENT ADJUSTMENTS

Proxy Return on Equity Adjustment

Q. PLEASE DESCRIBE YOUR PROXY ROE ADJUSTMENT.

A. I assumed the 10% ROE authorized by the Commission for the Distribution System Improvement Charge ("DSIC") included in the most recent Report on the Quarterly Earnings of Jurisdictional Utilities for the year ended December 31, 2024 produced by the Bureau of Technical Utility Services ("TUS").[1]

Q. DO ANY PARTIES TAKE ISSUE WITH YOUR USE OF THIS PLACEHOLDER ROE?

A. Yes. Wellsboro witness Dylan W. D'Ascendis testifies that while the range of ROEs calculated by the TUS in its quarterly report is generally consistent with both his initial and updated model results - and while the upper end of the TUS ranges

[1] Direct Testimony of Justin B. Farr (OSBA Statement No. 1) p. 13.

for gas and electric utilities aligns with his Company-specific recommendation - the TUS ranges do not account for the performance of Wellsboro's management. As a result, he argues the TUS analysis provides an incomplete basis for determining the Companies' appropriate ROE.[2]

OCA witness Christopher C. Walters states that he disagrees with my use of a 10% DSIC ROE from the Commission's Quarterly Earnings Report as a proxy ROE for the Company. He claims that the Commission has expressly and repeatedly rejected the use of its DSIC ROE for purposes of establishing the cost of equity in base rate proceedings and cites one case, a Pike County Light and Power rate case.[3] Mr. Walters concludes that because my proxy ROE is not grounded in a proper cost of equity analysis and is inconsistent with Commission precedent, the portion attributed to ROE of my proposed downward adjustment to the Company's revenue requirement should be rejected.[4]

Q. HOW DO YOU RESPOND TO THESE CONCERNS?

A. To clarify, I am not suggesting that the DSIC ROE be adopted in this proceeding in the absence of a detailed ROE analysis. My use of the proxy 10% DSIC ROE is not intended to replace the Commission's consideration of traditional cost of capital analyses offered by other parties in this proceeding.

Q. HAVE YOU ANALYZED THE IMPACT OF OTHER PARTIES' COST OF CAPITAL RECOMMENDATIONS ON YOUR REVENUE REQUIREMENT CALCULATIONS?

[2] Rebuttal Testimony of Dylan W. D'Ascendis (Joint Statement No. 2R) p. 3.
[3] Rebuttal Testimony of Christopher C. Walters (OCA Statement 2R) p. 14.
[4] *Id.* p.16.

A. Yes. In Table JBF-1SR I provide a summary of the total revenue increases that would result from utilizing I&E's and OCA's recommended return on equity in my revenue requirement calculations.

Table JBF-1SR
OSBA Revenue Increase with OCA and I&E ROE Recommendations

	Low	Mid	High
Source of ROE Assumption	OCA	OSBA	I&E
ROE Rate Assumption	9.50%	10.00%	10.78%
Total Revenue Increase*	$2,422,951	$2,513,149	$2,655,963
Difference from OSBA Direct	-$90,198	$0	$142,814

*Assumes adjustments made in OSBA Direct Testimony

For comparison purposes, Table JBF-2SR summarizes the total revenue increases that I recommended in my direct testimony, as well as those recommended by I&E, OCA, and Wellsboro.

Table JBF-2SR
Comparison of Proposed Revenue Increases

	Revenue Increase	Difference from Wellsboro
Wellsboro Application	$2,899,388	$0
OSBA Direct Testimony	$2,513,149	-$386,239
I&E Direct Testimony	$2,279,151	-$620,237
OCA Direct Testimony	$2,208,724	-$690,664

Performance Factor Adjustment and Size Adjustment

Q. PLEASE DESCRIBE YOUR PERFORMANCE FACTOR ADJUSTMENT AND SIZE ADJUSTMENT PROPOSALS.

A. I recommend eliminating the performance factor entirely and lowering or removing the size factor adjustment.[5]

Q. HOW DID WELLSBORO RESPOND TO YOUR PERFORMANCE FACTOR ADJUSTMENT?

A. Wellsboro witness Bryon Farnsworth Jr. states that the Company has made significant improvements to the reliability and resiliency of its distribution system. He provides examples of the Company's improvements. He claims that when the Company is planning system improvements and projecting their future financial situation, they rely on receiving consistent treatment by the Commission, including certainty on items such as the recognition of the size and performance adjustments which the Commission granted the Company in the past.[6]

Q. HOW DO YOU RESPOND TO WELLSBORO'S POSITION THAT THE COMPANY RELIES ON RECEIVING CONSISTENT TREATMENT BY THE COMMISSION, INCLUDING CERTAINTY ON ITEMS LIKE SIZE AND PERFORMANCE FACTOR ADJUSTMENTS?

A. Consistency cannot be the justification for perpetuating adjustments that are unwarranted. Wellsboro should not receive upward adjustments simply for meeting obligations that every regulated utility is required to meet. Nor should it benefit from adjustments intended to shield it from hypothetical or speculative risks. Wellsboro already operates under a framework that provides consistency and certainty, as a regulated utility, the Company is guaranteed a rate of return. That guarantee offers far greater consistency and certainty than what is available to

[5] Direct Testimony of Justin B. Farr (OSBA Statement No. 1) p. 11.
[6] Rebuttal Testimony of Byron Farnsworth, Jr. (Wellsboro Statement No. 4R) pp. 2-4.

nearly all other businesses subject to competitive market forces. Extending additional adjustments in the name of consistency would only reward Wellsboro beyond what is reasonable or necessary.

Q. DID I&E AND OCA MAKE PROPOSALS RELATED TO THE PERFORMANCE FACTOR ADJUSTMENT AND THE SIZE ADJUSTMENT?

A. Yes. Both I&E and OCA witnesses recommended eliminating the performance factor adjustment and the size adjustment.

Q. DOES THIS CONCLUDE YOUR SURREBUTTAL TESTIMONY?

A. Yes, it does.

EXHIBIT JBF-1SR

SURREBUTTAL TESTIMONY WORKPAPERS**

JBF WP-1SR Wellsboro HSG-1 with OSBA Adj and I&E ROE**

JBF WP-2SR Wellsboro HSG-1 with OSBA Adj and OCA ROE**

The above referenced workpapers will be served electronically in excel format ONLY, simultaneous to service of OSBA's Surrebuttal Testimony ONLY

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	**Docket No. R-2025-3054392**
v.	:	
	:	
Wellsboro Electric Company	:	

VERIFICATION

I, Justin B. Farr, hereby state that the facts set forth in my Surrebuttal Testimony and Exhibit, labelled OSBA Statement No. 1-SR, with associated Exhibit JBF-1SR, are true and correct to the best of my knowledge, information, and belief, and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements made herein are subject to the penalties of 18 Pa. C.S. § 4904 (relating to unsworn falsification to authorities).

Date: August 28, 2025

Justin B. Farr

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	**Docket No. R-2025-3054392**
v.	:	
	:	
Wellsboro Electric Company	:	

CERTIFICATE OF SERVICE

I hereby certify that true and correct copies of the foregoing have been served via email (*unless otherwise noted below*) upon the following persons, in accordance with the requirements of 52 Pa. Code § 1.54 (relating to service by a participant).

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Date: August 28, 2025

/s/ Rebecca Lyttle
Rebecca Lyttle
Assistant Small Business Advocate
Attorney ID No. 201399

BEFORE

THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	**:**	
	:	
v.	**:**	**Docket No. R-2025-_____**
	:	
Wellsboro Electric Company	**:**	

DIRECT TESTIMONY

AND EXHIBITS

OF

HOWARD S. GORMAN

ON BEHALF OF

WELLSBORO ELECTRIC COMPANY

APRIL 30, 2025

BEFORE

THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	**:**	
	:	
v.	**:**	**Docket No. R-2025-_____**
	:	
Wellsboro Electric Company	**:**	

DIRECT TESTIMONY OF HOWARD S. GORMAN ON BEHALF OF WELLSBORO ELECTRIC COMPANY

Q. Please state your name, occupation and business address.

A. My name is Howard Gorman. I am the President of HSG Group, Inc., a consulting firm specializing in utility rate and regulatory matters, located in Great Neck, NY.

Q. Please summarize your educational background and professional experience.

A. My educational background, professional experience and summary of testimony are outlined in Attachment A.

Q. Please state on whose behalf you are testifying and describe the purposes of your testimony.

A. I am testifying on behalf of the petitioner, Wellsboro Electric Company ("Wellsboro" or "Company"). The purposes of my testimony are:

- To develop the Fully Projected Future Test Year ("FPFTY") Revenue Requirement and Rate Base, and Future Test Year ("FTY") net income, based on Historic Test Year ("HTY") data and appropriate adjustments;
- To present the allocated class cost of service study that I performed; and

- To present the Company's proposed revenue allocation and the proposed Rates and Charges that produce the overall revenue requirement and the class revenue targets, as well as the proof of revenue and bill comparisons at the proposed rates. I will also discuss proposed changes to the rate structures for certain rate schedules.

The rates proposed in this filing are for the FPFTY; the FPFTY Revenue Requirement and Rate Base were determined for Distribution only. Revenue and costs related to Wellsboro Generation Supply Service Rate ("GSSR") were excluded from the analysis.

The supporting calculations and data for the filing are in Exhibit__(HSG-1). Throughout my testimony, I will reference the various schedules within Exhibit__(HSG-1) that explain the calculations and results. References in my testimony are to *Exhibit __ (HSG-1)*; for example, *Schedule C1* refers to *Exhibit __ (HSG-1), Schedule C1*.

In my testimony, dollar amounts (excluding rates and charges) are rounded to the nearest thousand dollars; in computing revenue requirements and rates, whole dollars are used.

Q. What HTY, FTY and FPFTY were used?

A. The HTY is Wellsboro's actual results for calendar year 2024. The FTY is Wellsboro's forecast for 2025 and the FPFTY is Wellsboro's forecast for 2026. Wellsboro uses a calendar year for financial reporting.

When will the new rates take effect?

A. If the Commission suspends the filing for the statutory period, then the rates will take effect on January 30, 2026; however, the rate changes could be effective sooner if the Commission doesn't suspend the filing or if the parties reach a settlement that includes an accelerated effective date and that settlement is approved by the Commission.

Q. Is the presented FPFTY consistent with the Commission's revised regulations for rate cases using a FPFTY?

A. Yes. Earlier this year, the Commission adopted revised regulations for Sections 53.51-53.56 that are pending before the Independent Regulatory Review Commission, with final action expected soon after the Company submits this filing. The revised regulations contain the following definition of FPFTY:

> A 12-consecutive-month period beginning with the first month that the new rates will be in effect after application of the full suspension period permitted under section 1308(d) of the Public Utility Code, 66 Pa.C.S. § 1308 (relating to voluntary changes in rates) and reflecting estimated results of operations of the public utility.

Q. Please summarize the results of your testimony regarding Wellsboro's revenue requirement.

A. Under the present rates, Wellsboro would have a shortfall of approximately $2,899,000 in revenue compared to revenue requirements for the FPFTY (Schedule C1). Wellsboro is proposing that the rates and charges subject to the Tariff be increased as shown on Schedule B7. This would increase its distribution revenue in the FPFTY by 45.3%. This equals an increase in total revenue (distribution and supply) of 22% of Wellsboro's 2024 total revenue.

Based on Wellsboro's as-filed increase, the average annual increase in distribution revenue from the prior rate case (with new rates effective May 1, 2020) to 2026 is 6.8% per year.

The revenue produced by the as-filed rate increase, approximately $9,301,000 (plus $328,000 Other revenue, for a total revenue requirement of $9,629,000) would recover the costs forecast to be incurred by Wellsboro in the FPFTY, including a return on rate base of

8.18%, as shown on Schedule C1, as supported by Company witnesses Dylan D'Ascendis and Ryan Kucan of ScottMadden, Inc.

Q. Please summarize the Company's proposed revenue allocation and rate design.

A. The Company's proposed revenue allocation is presented on Schedule B6-4, line 24, and the proposed revenue increase on line 36. This schedule also shows, for each rate class, 1) return on rate base at the proposed revenue allocation (line 32); 2) relative return compared to system average (line 33); 3) progress toward unity (line 34), which measures how much of the gap between x) relative return at present rates and y) relative return at proposed revenue allocation, is closed based on the proposed revenue allocation; and 4) change in subsidy paid (received) (lines 41-44), where the subsidy is the difference between xx) rate of return produced by the rate class and yy) average rate of return, applied to the rate base allocated to the class.

The Company's proposed rates are presented on Schedule B6-3, lines 19-30, and also on Schedule B7. Schedule B6-3 demonstrates that the proposed rates produce the class revenue targets (except for rounding) (lines 38-39).

Q. Is the Company allocating the same percentage increase to every customer class?

A. No. The Company used the results of the ACOS to allocate the proposed increase among customer classes to move the classes closer to the cost-to-serve as indicated in the ACOS.

Q. Are you sponsoring any exhibits?

A. Yes. Exhibit ___ (HSG-1), Schedule A presents an Index of the exhibits supporting the Company's revenue requirement of $9,301,000 and increase of $2,899,000.

Q. Please describe the approach used to develop the Company's revenue requirement and proposed rates.

A. *First*, the FTY and FPFTY forecast of sales and distribution revenue was developed. Information about HTY sales and revenue was obtained from Wellsboro accounting and financial records provided by Company witness Jill Campbell. Summary information on sales and revenues is presented in Exhibit __ (HSG-1), Schedule B. Information for HTY 2024 is on Schedule B1, with supporting computations on Schedule B1-1. Schedule B4 presents a reconciliation of HTY 2024 revenue to Wellsboro's financial statements. Sales and revenue information for FTY 2025 is on Schedule B2, with supporting computations on Schedule B2-1. Sales and revenue information for FPFTY 2026 is on Schedule B3, with supporting computations on Exhibit Schedule B3-1.

Second, costs were obtained for the HTY, and forecasted costs were obtained for the FTY and FPFTY. These costs, detailed by account, are presented on Schedule C1-1.

Third, the Rate Base for the HTY, FTY and FPFTY was developed, using information for the HTY, projected capital expenditures for the FTY and FPFTY and computing annual depreciation expense. In addition, accumulated deferred income taxes, excess deferred income taxes, cash working capital allowance and other rate base components were computed. These computations are shown on Schedule C1-5.

Fourth, the required Net Utility Operating Income was developed using the FPFTY costs and rate base, and the required rate of return developed by Mr. D'Ascendis and Mr. Kucan. This computation indicated that FPFTY revenue of $9,629,000 (including Other revenue) is needed to produce the required rate of return. These results are presented on Schedule C1, which also shows the rate of return for the HTY, FTY and FPFTY at present rates.

Fifth, the ACOS (Schedule E) was performed to develop the share of the total revenue requirement attributable to each rate class.

Finally, proposed rates were developed that produce the required FPFTY revenue. The proposed rates are shown on Schedules B6-3 and B7. The amounts that typical ratepayers can expect to pay under the proposed rates are compared to the amounts they would pay under the present rates on Schedule B8 (including current GSSR) and Schedule B8-1 (excluding GSSR). Schedule B8-2 provides the rate comparisons on a total rate basis using the GSSR that is expected to take effect on June 1, 2025. Schedule B6-3 demonstrates that the proposed rates produce the required revenue.

Q. What are the reasons that Wellsboro needs an increase in rates at this time?

A. Schedule C5-1 presents the financial drivers for the requested rate increase by comparing the FPFTY to Wellsboro's last rate case, Docket R-2019-3008208.

Q. What service classifications does Wellsboro use to report sales and revenue?

A. Wellsboro reports sales and revenue using the following service classifications:

Schedule 1- Residential Service (RS)
Schedule 2- Residential Service All Electric (RSAE)

Schedule 3- Non-Residential Service (NRS), Non-Residential Space Heating (NRH)
Schedule 4- Commercial Service (CS) and Commercial Space Heating (CSH)
Schedule 5- Industrial Services (IS)

Schedule 6- Municipal Streets Lights (MSL)
Schedule 7- Private Outdoor Lighting Service (POL)

Schedule 8- Sales for Resale (Exchange of Service (EU))

Q. What types of charges are in the current Tariff?

A. Schedule 1 (RS) rates include a fixed monthly charge, a per-kWh distribution charge and the per-kWh GSSR charge.

Schedule 2 (RSAE) rates include a fixed monthly charge, a per-kWh distribution charge and the per-kWh GSSR charge.

Schedule 3 (NRS) rates include a fixed monthly charge, a per-kWh distribution charge and the per-kWh GSSR charge.

Schedule 3 (NRH) rates include a fixed monthly charge, a per-kWh distribution charge and the per-kWh GSSR charge.

Schedule 4 (CS) rates include a fixed monthly charge, a per-kWh distribution charge, a distribution per-kW (demand) charge (with a 50% ratchet based on past 11 months actual demand but not less than 7 kW), and the GSSR charge, which may be the GSSR-1 (per-kWh) or the GSSR-2 (per-kWh and per-kW (demand) components).

Schedule 4 (CSH) rates include a fixed monthly charge, a per-kWh distribution charge and the GSSR charge, which may be the GSSR-1 (per-kWh) or the GSSR-2 (per-kWh and per-kW (demand) components).

Schedule 5 (IS) rates include a fixed monthly charge, a distribution demand (per-kW) charge (with a 50% ratchet based on past 11 months), a two-block per-kW distribution charge and the GSSR charge, which may be the GSSR-1 (per-kWh) or the GSSR-2 (per-kWh and per-kW (demand) components). The per-kWh distribution charge has two blocks, with the number of kWh in the first block based on the customer's billed demand for the month.

Schedule 6 (MSL) rates and Schedule 7 (POL) rates include a fixed monthly distribution charge per lamp and the per-kWh GSSR charge.

Schedule 8 (EU) rates include a per-kWh distribution charge.

All customers are billed monthly.

Q. Is the Company proposing any rate structure changes?

A. No, the Company is not proposing any rate structure changes.

HTY INFORMATION

Q. Please identify and describe the exhibits that show HTY sales and revenue.

A. Schedule B shows total revenue by customer type for HTY 2024, and distribution-only revenue for HTY 2024, FTY 2025 and FPFTY 2026. HTY total revenue is $13,158,392 based on Wellsboro's financial statements. The HTY distribution-only amounts is total revenue amounts minus GSSR and Transmission revenue. The HTY total revenue amounts are from Schedule B1, which is supported by detailed computations on Schedule B1-1, using present rates and HTY billing units. The billing units are sales in kWh, numbers of customer bills and demand in kW.

Q. Please describe the HTY information regarding costs.

A. Schedule C1-1 shows the details of operating expenses by function for the HTY. This exhibit is described in detail later in my testimony.

Q. Please describe the HTY information regarding rate base and Rate of Return.

A. Schedule C1-5 computes the rate base for the HTY. Schedule C1 shows the return on rate base for HTY 2024 was 3.97% for distribution-only.

FTY AND FPFTY SALES AND REVENUE

Q. Please identify and describe the exhibits that show FTY 2025 and FPFTY 2026 sales and revenue at present rates.

A. Information on sales and revenue is presented in Schedule B. For HTY 2024, sales were approximately 97 million kWh, with approximately 160,000 kW billed demand.

For FTY 2025, the sales forecast represents normalized annual use per customer times expected number of customers. Normalized annual use per customer was developed by Wellsboro in a special study. The number of customers equals average number of customers in 2024 plus expected growth. Sales for FTY 2025 are projected at

approximately 104 million kWh (Schedule B2-1, line 2), and distribution revenue is projected to be $6,380,000 (Schedule B2-1, line 39).

For FTY 2026, the sales forecast used the same normalized annual use per customer, and additional growth in the number of customers. Sales for FPFTY 2026 are projected at approximately 106 million kWh (Schedule B3-1, line 2), and distribution revenue is projected to be $6,400,000 (Schedule B3-1, line 39).

FTY AND FPFTY COSTS

Q. Please list the types of costs included in FTY and FPFTY costs.

A. FTY and FPFTY costs include Operating and Maintenance costs ("O&M") and Non-operating costs. O&M costs include Purchased Electricity, Distribution expenses, Customer accounting and collection expenses, Sales and public relations expense and Administrative & General expenses. Non-operating costs include Depreciation expense, Taxes other than income, Rate case expense amortization and Income tax expense.

Q. How did you develop the FTY and FPFTY O&M costs?

A. HTY actual O&M costs, totaling $9,252,000, are summarized on Schedule C1, line 18. Schedule C1-1 shows the detail of O&M costs by account for 2023 and HTY 2024 (actual) and for FTY 2025 and FPFTY 2026 (forecast). The costs are carried forward to Schedule C-1. Schedule C1-1, lines 51-55, presents a summary of costs by type (labor, overhead, transportation, materials).

The columns to the right of HTY actual O&M costs on Schedule C1-1 show the changes between HTY 2024 and FTY 2025; the columns to the right of FTY 2025 show the changes between FTY 2025 and FPFTY 2026.

The Labor portion of each O&M account is also shown on Schedule C1-1.

The HTY, FTY and FPFTY costs are summarized and carried forward to Schedule C1.

Q. How was Depreciation expense computed for each year?

A. Schedule C3, page 1, shows the asset values at original cost in PAPUC / FERC account detail as of December 31, 2023, actual additions and retirements during HTY 2024, and planned additions for FTY 2025 and FPFTY 2026.

Schedule C3, page 2, shows the depreciation rate applicable to each account, and depreciation expense for each year. The annual depreciation expense for each asset account was computed by multiplying X) the depreciation rate for the asset account times Y) original cost at prior year end plus one-half of the additions for the year. The total FPFTY depreciation expense, less the amount charged to clearing accounts and recovered in O&M costs, is $1,939,000; this amount is carried forward to Schedule C1.

Schedule C4 shows the Reserve for Depreciation at the ends of the HTY, FTY and FPFTY.

Q. How did you compute Taxes other than income for FTY 2025 and FPFTY 2026?

A. Schedule C1-3 shows the components of Taxes other than income.

The Pennsylvania Use Tax and the Public Utility Realty Tax are assumed to be the same in FTY and FPFTY as in HTY. The Pennsylvania Gross Receipts Tax ("GRT") is computed by applying the tax rate of 5.90% to the applicable revenue for each year.[1] The FTY and FPFTY totals are carried forward to Schedule C1.

Q. How did you compute the FPFTY Rate case expense amortization?

A. The Rate case expense amortization reflects the normalized rate case expense. Expenses for the pending rate case, if fully litigated, are estimated at $331,000 and a three-year

[1] The effective tax rate is calculated using the 59 mills GRT.

normalization period was determined to be reasonable, starting January 1, 2026 (the start of the FPFTY). The computation is shown on Schedule C1-3 and the result is included in Account 928 on Schedule C1-1.

Q. How did you compute the FTY and FPFTY Income tax expense?

A. Income tax expense for the FTY and FPFTY is computed on Schedule C1-4.

Net operating income before income taxes (line 1), is from Schedule C1, line 25.

Synchronized interest expense (lines 3-8) is computed by multiplying rate base (Schedule C1, line 30) and by the weighted cost of debt (Schedule C1-2).

Taxable income before depreciation tax adjustments (line 9) is equal to Net operating income before income taxes less Synchronized interest expense.

Regulatory Pennsylvania taxable income and Regulatory Pennsylvania tax expense are computed using the Full flow through method; that is, tax depreciation is used in the computation. The Pennsylvania depreciation adjustment (lines 11-14) reflects the depreciation expense on Wellsboro's Pennsylvania tax return and is computed using the double declining balance method applied to tax basis and tax life (just as on the tax return). Regulatory Pennsylvania taxable income (line 15) is equal to Taxable income before depreciation tax adjustments as adjusted by the Pennsylvania depreciation adjustment. Regulatory Pennsylvania income tax expense (line 16) is equal to Regulatory Pennsylvania taxable income times the statutory 9.99% rate.

Regulatory Federal taxable income and Regulatory Federal tax expense are computed using a modified Full flow through method; that is, a modified tax depreciation amount is used in the computation. The Federal depreciation adjustment (lines 19-21), is based on the straight line method applied to tax basis and tax life. Federal taxable income (line 26) is

equal to Taxable income before depreciation tax adjustments as adjusted by the Federal depreciation adjustment and less Regulatory Pennsylvania tax expense. Regulatory Federal income tax (line 27) is equal to Regulatory Federal taxable income times the statutory 21% rate.

Regulatory Total income tax expense (line 29) is equal to Regulatory Pennsylvania income tax expense plus Regulatory Federal income tax expense, and is carried forward to Schedule C1, line 27.

Q. Does the computation of income tax expense included in the revenue requirement comply with Act No. 40 of 2016, which amends the Public Utility Code regarding the treatment of income tax expense for ratemaking purposes?

A. Yes. The computation of income tax expense for ratemaking purposes, presented on Schedule C1-4 (i.e., in the revenue requirement), reflects a tax deduction for each item of expense of investment (i.e., depreciation expense) in the revenue requirement. In addition, there are no items that reduce the income tax expense for ratemaking purposes, or increase the deferred tax liability, other than reflected in the revenue requirement.

Q. Did you compute the Net Utility Operating Income and Return on Rate Base at present rates?

A. Yes. Schedule C1, line 28 and Schedule C5, line 14 show Net Utility Operating Income at Present Rates for the HTY, FTY and FPFTY. Schedule C1, line 31 shows Return on Rate Base for distribution-only at present rates of 3.97% for the HTY, 1.44% in FTY 2025 and 0.68% in FPFTY 2026.

RATE BASE FOR THE FTY AND FPFTY

Q. How did you develop the Rate Base?

A. The Rate Base at the end of the HTY, FTY and FPFTY is presented in Schedule C1-5. Assets at original cost and accumulated depreciation are carried forward from Schedule C3. Schedule C3 shows assets, accumulated depreciation and annual depreciation expense, as discussed above.

The HTY amounts for Customer deposits and Materials and supplies are from Wellsboro's financial statements at December 31, 2024. These items were estimated to be the same for the FTY and the FPFTY as for the HTY.

The rate base includes a reduction for Accumulated deferred income taxes ("ADIT"), equal to the difference between Accumulated depreciation based on X) Federal tax expense borne by ratepayers (i.e., based on straight line method, discussed above) and Y) Wellsboro actual tax Federal tax expense (i.e., based on double declining balance method), times the current Federal income tax rate. The ADIT is computed on Schedule C1-5, lines 27-32 and carried up to Schedule C1-5, line 6.

The rate base includes a reduction for Accrued Pension / OPEB liability, reflecting the excess of amounts charged to expense over amounts paid (Schedule C1-5, lines 42-46, carried up to Schedule C1-5, line 9).

An allowance for Cash Working Capital was determined by using the widely-accepted formula of 1/8 of non-fuel cash operating costs (Schedule C1-5, lines 15-25, carried up to Schedule C1-5, line 12).

Total Rate Base, Schedule C1-5, line 13, is carried forward to Schedule C1, line 30.

NET UTILITY OPERATING INCOME

Q. What is the distribution revenue requirement for the FPFTY?

A. The FPFTY distribution revenue requirement (excluding Other income) is $9,301,000, as shown on Schedule C1.

Q. What revenue is included in the distribution revenue requirement?

A. The total revenue requirement includes:

- Electric operating revenue: Revenue from distribution of electricity, including exchange with other utilities.
- Other Revenue: Other revenue includes Forfeited Discounts (late payment charges) and Revenue from rental of electric property.
- Unbilled Revenue: Because the FPFTY is fully normalized, there is no unbilled revenue.

Q. What rate of return on rate base did Mr. D'Ascendis and Mr. Kucan recommend?

A. Mr. D'Ascendis and Mr. Kucan recommended a return of rate base of 8.18%.

Q. What rate of return on rate base does the proposed revenue requirement produce?

A. The proposed revenue requirement produces a rate of return of 8.18%, on the rate base of $25,857,000 (Schedule C1). The distribution revenue requirement (excluding Other income) needed to produce this rate of return is $9,301,000 (Schedule C1, line 7).

ALLOCATED CLASS COST OF SERVICE STUDY

Q. Please briefly describe the purpose of an allocated class cost of service study.

A. The purpose of an allocated class cost of service study ("ACOS") is to assign, on a cost-causation basis, the total distribution revenue requirement of a utility among the rate classes

in its Tariff. In performing the ACOS, all of the utility's costs of providing service are analyzed, in order to assign or allocate the costs among the rate classes, so that the utility can establish rates that ensure, subject to assumptions such as delivery volumes and customer counts, that it recovers its costs in full from each class.

Q. What are the guiding principles in performing an ACOS?

A. The essential element in performing an ACOS is the selection of allocators based on causal relationships between customer demands, load profiles and usage characteristics on one hand, and the costs incurred by the Company to meet those requirements on the other hand. The primary goals in selecting allocators are:

1. recognition of **cost causality** as opposed to **value of service**;
2. **stability** of results over time;
3. logical **consistency** and **completeness**; and
4. ease of implementation.

Q. What rate classes are included in Wellsboro's ACOS?

A. The rate classes included in Wellsboro's ACOS are Schedule 1- Residential Service (RS), Schedule 2- Residential Service All Electric (RSAE), Schedule 3- Non-Residential Service (NRS) and Non-Residential Space Heating (NRH), Schedule 4- Commercial Service (CS) and Commercial Space Heaters (CSH), Schedule 5- Industrial Services (IS), Schedule 6- Municipal Streets Lights (MSL), Schedule 7- Private Outdoor Lighting Service (POL) and Schedule 8- Sales for Resale (Exchange of Service (EU)).

Q. Please summarize the approach you followed in preparing Wellsboro ACOS.

A. The most critical task in performing an ACOS is establishing relationships between customer demands, load profiles and usage characteristics on one hand, and the costs

incurred to meet those requirements on the other hand. This requires an understanding of the utility system design and its relationship to the characteristics of the customers it is designed to serve. Wellsboro, like most utilities, designs its electric distribution system to meet three primary objectives:

1. To extend distribution services to all customers;
2. To deliver the aggregate peak demand for electricity of all firm delivery customers; and
3. To deliver electricity to customers throughout the year.

The allocation of costs in a class cost of service study must recognize these ***cost-causative*** characteristics of the utility's plant investments and operating expenses. A cost of service study should objectively reflect cost-causation factors and should not be influenced by end-results, customer equity or other *revenue allocation and rate design* considerations.

Wellsboro's ACOS follows the traditional three-step process: 1) *functionalization* of rate base and costs; 2) *classification* of functionalized costs as demand-related, commodity-related or customer-related; and 3) *class allocation* of the functionalized, classified costs among the rate classes.

Q. What functions are included in the ACOS?

A. Wellsboro's ACOS includes the following functions:

Primary Distribution - Designed to move power from the transmission system to the Secondary Distribution system; includes substations as well as conductors operating primarily at voltages of over 600V up to and including 12 kV, and related assets.

Secondary Distribution - Designed to move power from the Primary Distribution system to customers' premises; includes services.

Billing - Includes meter as well as assets and activities related to enabling the distribution of electricity to customers, and billing and collecting revenue.

Q. Wellsboro owns a limited number of 115 kV facilities. How did you address those facilities in the ACOS?

A. Wellsboro's 115 kV facilities are limited to equipment at the substation where it accepts power 115 kV power from MAIT that is stepped down to distribution voltage. These facilities are functionally equivalent to the Primary Distribution facilities and have been treated as such in the ACOS.

Q. Please describe the classification step of an ACOS.

A. In the **classification** step, the previously functionalized assets and costs are separated according to the system design or operating characteristics that cause those costs to be incurred in the first instance. Each asset and cost is determined to be incurred to serve **customers**, to deliver the electricity or **commodity** year-round or to meet peak **demand** including coincident and non-coincident peaks ("NCPs").

Customer related costs are the costs incurred to attach a customer to the distribution system, to meter usage and to maintain the customer's account. Customer costs are a function of the number of customers served and continue to be incurred whether or not the particular customer uses any electricity. They include capital costs associated with services and meters, and operating costs such as customer service, field service, billing and accounting expenses.

Commodity related costs are those costs that vary with the quantity of electricity delivered throughput sold to, or transported for, customers. These costs include purchased electricity costs and related costs.

Demand, or **capacity**, related costs are associated with plant that is designed, installed and operated to meet peak usage. Distribution assets are designed to meet the peak loads of the particular customers they serve.

Q. Please describe the class allocation step of an ACOS.

A. In the **class allocation** step, the functionalized, classified costs are allocated among the rate classes, based on causal relationships with the utility's design and operations, its accounting records and its system and customer usage and load data. Based on those analyses of cost relationships, each plant and cost item in the rate base and revenue requirement is directly assigned to a rate class, or an allocator is selected to apportion the item.

Q. Please explain the term "direct assignment."

A. The term "direct assignment" means identifying plant investments or costs incurred exclusively to serve a specific customer or group of customers. Direct assignments best reflect the cost-causation of serving individual customers or groups of customers, and should be used whenever the data are available.

Q. In a typical ACOS are most costs directly assigned, or are most costs allocated?

A. Most costs must be allocated, because utility operations are characterized by common facilities. In addition, direct assignments require detailed information which may be unavailable or require a great deal of time to prepare. The assets and costs that cannot be directly assigned are distributed among the rate classes using allocation factors.

Q. Please explain how allocators are derived.

A. Two types of allocators are typically used in performing an ACOS: external allocators and internal allocators. *External allocators* are based on special studies derived from the utility's accounting and other records. Examples of external allocators are number of

customers and NCPs. Schedule D lists the external allocators used in the ACOS, and Schedules D1 through D6 show the development of the external allocators.

Internal allocators are based on some combination of external allocators, previously directly assigned costs and other internal allocators. For example, the allocator for property insurance costs is based on plant investment amounts assigned to components of the rate base; as a result, it is necessary to compute the rate base before property insurance costs can be allocated. Both external and internal allocators are used in functionalization, classification and class allocation.

Q. What is the rate base and how is it used in the ACOS?

A. The rate base is the cost, net of accumulated depreciation, of Wellsboro investment in plant and other assets used to serve customers. The FPFTY rate base is $25,857,000 (Schedule C1). The revenue requirement reflects the return on the rate base of 8.18%, as discussed above. The ACOS allocates the rate base (and return on rate base) among rate classes.

Q. What are the major components of Wellsboro's rate base?

A. In discussing how I functionalized, classified and allocated the rate base in the ACOS, I will refer to the following major rate base categories:

- Distribution plant
- Intangible plant
- General plant
- Depreciation reserve
- Other rate base items

Q. How was distribution plant functionalized, classified and allocated among the rate classes?

A. Distribution plant comprises:

Land and Land Rights and Stations Equipment were functionalized to Primary Distribution, classified as demand and allocated among the rate classes using the NCP-Primary allocator.

Poles, Towers and Fixtures; Overhead Conductors and Devices; Underground Conduit; Underground Conductors & Devices were functionalized between Primary and Secondary based on circuit miles / lines miles (Schedule D1, lines 1-28).

The Primary portion was classified as demand-related and allocated among the rate classes using the NCP- Primary allocator.

The Secondary portion was classified between customer-related and demand-related using a zero-load analysis. The portion of total installation costs that are labor-related (i.e., all costs except material) were classified as customer-related, and the balance as demand-related (Schedule D1, lines 29-48). The zero-load component of the Secondary system represents the cost of extending service to all customers, without regard to peak or average load, and is therefore customer-related. The assets and costs functionally classified to Secondary-customer were allocated among the rate classes based on number of customers served at Secondary voltages. The assets and costs functionally classified to Secondary-demand were allocated using the NCP- Secondary allocator.

Line Transformers were functionalized to Secondary and classified between customer-related and demand-related using a minimum size analysis (Schedule D3). The minimum size was determined to be a 10 kVA transformer serving one customer. The minimum size portion was classified as customer-related and allocated among the rate classes based on number of customers served at Secondary voltages. The balance of costs were classified

as demand-related and allocated using the NCP-LTr allocator, which is the NCP-Secondary allocator reduced by the load-carrying capacity of the minimum size transformers (Schedule D2, lines 18-22).

Services connect individual customers to the system, and were functionalized to Secondary, classified as customer-related and allocated based on total replacement cost for each class (Schedule D4). Total replacement cost of Services for a class was computed as X) estimated replacement cost of a typical service for the class times Y) number of customer locations in the class.

Meters were functionalized to Billing, classified as customer-related and allocated based on total replacement cost for each class (Schedule D5). Meter costs include CT (current transformers) and PT (Potential transformers). Total replacement cost of Meters for a class was computed as X) estimated replacement cost of meters for the class times Y) number of customers in the class.

Street Lighting and Signal Systems were functionalized to Secondary Distribution, classified as customer-related and directly assigned to Lighting.

Q. What is the NCP-Primary allocator and how was it developed?

A. The NCP-Primary allocator (or "NCP-Prim") is used in the ACOS to allocate among the rate classes, the assets and costs that are functionalized to Primary distribution. To develop the NCP-Prim allocator, I first computed the annual peak demand for each customer class, for each year 2018-2024. Then I determined the annual sum of the class peaks, and computed each class' share of the annual sum. The NCP-Prim allocator is each class' average share of annual peaks. By averaging shares over an extended period, fluctuations due to weather, economy and other events are smoothed out.

In computing the NCP-Primary allocator, metered values were used. A more refined analysis would reflect losses (i.e., by transforming the metered values to primary-level values), which have a slight effect on the relative NCP-Primary values for each class.

Q. What is the NCP-Secondary allocator and how was it developed?

A. The NCP-Secondary allocator (or "NCP-Sec") is used in the ACOS to allocate among the rate classes the assets and costs that are functionalized to Secondary distribution and classified as demand-related, except for Line Transformers (and assets and costs that include Line Transformers).

The NCP-Secondary allocator value for each rate class is the sum of the peak demands of the individual customers in the class, excluding customers that are served at Primary voltages (Schedule D2, lines 14-16).

Q. What is the NCP-Line-Transformer allocator and how was it developed?

A. The NCP-Line-Transformer allocator (or "NCP-LTr") is used in the ACOS to allocate among the rate classes the cost of Line Transformers that are functionalized to Secondary distribution and classified as demand-related. It represents the demands on the Secondary distribution system in excess of the minimum system and is equal to the NCP-Secondary allocator values, minus the load-carrying capacity of the minimum size transformers (Schedule D2, lines 18-22).

Q. How was Intangible plant functionalized, classified and allocated among the rate classes?

A. Intangible plant is the Company's investment in EDI (Electronic Data Interchange) software. The EDI software performs a variety of functions for customers that purchase supply from an Electric Generation Supplier ("EGS") and those that want to shop for an

EGS. EDI enables customers that shop to receive a bill from their EGS for supply, if they choose. The data to be transmitted via EDI includes customer identification; date of service; kWh usage; and total monthly bill (distribution items). The EDI software will also permit customers to switch suppliers on three business days' notice. In the ACOS, the costs were allocated on a per-customer basis because the same data is made available for each customer, regardless of the customer's rate class, usage, demand or shopping status.

Q. How was General plant functionalized, classified and allocated among the rate classes?

A. General plant includes primarily Structures and improvements, Office furniture and equipment, Computers and Communications equipment, as well as other assets. These assets were functionalized, classified and allocated among rate classes based on the direct labor content of operating expenses, reflecting the nature of the assets and common cost of service practice.

Q. How was Depreciation reserve functionalized, classified and allocated among the rate classes?

A. Each component of the Depreciation reserve was functionalized, classified and allocated among rate classes in the same ratio as the related assets.

Q. How were other Rate Base Items functionalized, classified and allocated among the rate classes?

A. Other Rate Base Items were functionalized, classified and allocated as follows:

Cash working capital represents Wellsboro's need for cash to keep the business running until revenues are collected to pay costs. This item was functionalized, classified and allocated among the rate classes in proportion to operating expenses.

Materials and supplies was functionalized, classified and allocated among rate classes in proportion to operating expenses.

Customer Deposits were directly assigned between Residential and Non-residential, then allocated among the rate classes based on revenues (Schedule D6).

ADIT was functionalized, classified and allocated among rate classes in proportion to plant in service.

Accrued Pension / OPEB Liability was functionalized, classified and allocated among rate classes in proportion to labor content of O&M expense accounts.

Q. What are the major categories of Wellsboro costs?

A. The major cost categories in Wellsboro cost of service are:

- Distribution operating and maintenance expenses
- Customer accounts and service expenses
- Administrative and general expenses
- Depreciation expense
- Tax expense, other than on income
- Income tax expense

Q. In determining how to treat these costs in the ACOS, was any other important category of costs considered?

A. Yes, labor costs affect most of the cost categories because many costs are assigned based on the direct labor content of other costs. For example, Administrative & General Salaries, Account 920, is allocated among rate classes based on the direct labor content of operating expense accounts. To perform these allocations, the direct labor content of each cost account was provided by Wellsboro, and appropriate allocators were developed.

Q. What costs are included in distribution operating and maintenance costs and how were they functionalized, classified and allocated among the rate classes?

A. Wellsboro's distribution operating and maintenance costs include operating and maintenance costs for its distribution system including stations; poles, towers and fixtures; overhead and underground conductors and related equipment; meters; line transformers; lighting; and other assets. Each cost was analyzed to determine which assets it was incurred to operate or maintain, and the cost was functionalized, classified and allocated among rate classes in the same manner as those assets. For example, Miscellaneous distribution expenses, Account 588, relates to the Overhead and Underground assets, and was functionalized, classified and allocated in proportion to those assets.

Q. What costs are included in customer accounts and service expenses and how were they functionalized, classified and allocated among the rate classes?

A. Customer-accounts costs includes primarily meter-reading expenses, customer records and collection expenses and uncollectible-accounts expense. These costs were functionalized to Billing and classified as customer-related.

Meter reading expenses were allocated among the rate classes in proportion to Meter costs.

Customer records and collection expenses includes activities for billing, call center, payment processing, recoveries and service initiation / termination, and were allocated based on the number of customers.

Uncollectible accounts expense was directly assigned between Residential and Non-residential based on Wellsboro historic data, then allocated among the specific rate classes based on revenues (Schedule D6).

Q. How were Administrative and general expenses functionalized, classified and allocated among rate classes?

A. Administrative and general ("A&G") expenses comprises the following:

Administrative and general salaries, Office supplies and expense, and Employee benefits were functionalized, classified and allocated among rate classes based on labor content of the operating and maintenance and customer accounting costs. Most Employee benefits costs are included in the O&M and customer accounting accounts, and not in A&G costs.

Property insurance, Injuries and damages and Maintenance of general property were functionalized, classified and allocated based on plant costs.

Outside services and Miscellaneous general expenses were functionalized, classified and allocated based on a 50/50 weighting of labor and plant costs.

Regulatory commission expenses were functionalized to Billing, classified as customer-related and allocated among rate classes in proportion to rate base.

Q. How was depreciation expense functionalized, classified and allocated among the rate classes?

A. Depreciation expense was computed for each asset account (Schedule C3); each component was functionalized, classified and allocated among rate classes in proportion to the related assets.

Q. How were taxes other than GRT and income taxes functionalized, classified, and allocated among the rate classes?

A. These taxes are includes PURTA, Real estate tax and Use taxes, which were functionalized, classified and allocated among rate classes in proportion to plant.

Q. How was GRT functionalized, classified, and allocated among the rate classes?

A. GRT is based on revenue, and GRT at present rates was computed for each function, classification and rate class on that basis. In computing the revenue requirement, the GRT expense for each class was computed based on class revenue requirements.

Q. How was income tax expense functionalized, classified and allocated among rate classes?

A. Income tax expense in the FTY was functionalized, classified and allocated in proportion to pretax income. In computing the revenue requirement, Income tax expense was computed for each class based on the pretax income needed to produce the revenue requirement for the class.

Q. How was revenue at present rates computed for each rate class?

A. Distribution revenue at present rates is shown on the proof of revenue at Schedule B1. The total was functionalized and classified based on pro forma revenue requirements, and was assigned to each rate class based on forecast revenue at present rates for each rate class.

Forfeited discounts was functionalized to Billing and allocated based on historical experience for write-offs.

Rent for Electric Property represents pole rental revenue and was functionalized, classified and allocated in proportion to Poles, Towers and Fixtures.

Other Electric Revenue was allocated among the rate classes in proportion to Distribution revenue.

Q. How was the revenue requirement for each rate class developed?

A. The revenue requirements for each rate class are computed in the same manner as for the total Company, as shown on Schedule C1. The revenue requirement for each rate class is the sum of its allocated operating expenses, depreciation expense, general taxes, return on

rate base and income tax expense. Return on rate base was computed by multiplying the class' rate base by the proposed system average Rate of Return. Income tax expense for each class was computed by grossing up the required return on rate base for the class at the income tax rate related to the overall revenue requirement. GRT for each class was computed by grossing up the required revenue for the class including income tax rate. Schedule E-1A, line 190 and Schedule E-1, line 13, show the total rate class revenue requirements based on fully allocated distribution cost of service at the proposed system Rate of Return.

Q. Please summarize the results of the ACOS.

A. Schedule E-1, shows Net income at present rates for each rate class (line 7) and Return on rate base at present rates (line 11). It also shows the revenue requirement for each class to produce the proposed system return of 8.18% (line 13) and the increase or decrease this represents over revenue at present rates (line 28).

PROPOSED REVENUE ALLOCATION

Q. What were the considerations in the proposed revenue allocation for each class?

A. The following objectives were established for the proposed revenue allocation:

1. To move each class closer to its cost of service, as computed in the ACOS (Schedule E-1).
2. To mitigate extreme rate impacts on rate classes and on customer subgroups.

Q. Have you prepared a schedule that presents the proposed revenue allocation?

A. Yes, Schedule B6-4 presents the proposed revenue allocation and related information. Line 20 presents the increase required for each class to produce a return of 8.18%, and line 24 presents the proposed distribution revenue including the increase.

Lines 1-8 show net income and return on rate base at present rates. Lines 11-21 show the revenue requirement for each class to provide a return of 8.18%. This information is from the ACOS summary at Schedule E-1.

Line 34 computes progress toward unity (i.e., the system average return) for each class, by dividing a) the difference line between relative return at proposed rates (line 33) and relative return at present rates (line 8), by b) the difference between unity and relative return at present rates (line 8). For example, Residential would move from a relative return of (3.52)X system average return, to a relative return of 0.75X system average return; so Residential would move from 452 percentage points away from system average at present rates to 20 points away at proposed, which reduces the gap by 432 percentage points out of 452, or 95% of the difference.

Line 38 shows the percent change in total revenue, assuming 100% sales.

Q. Please summarize why you believe the proposed revenue allocation presented at Schedule B6-4 is fair and reasonable.

A. The revenue allocation is fair and reasonable because almost all classes make significant progress toward the system average return (Schedule B6-4, line 34), meeting the goal of moving each class closer to cost of service; and no class receives an increase greater than 75% (Schedule B6-4, line 37), meeting the goal of mitigating extreme impacts. In addition, most classes have significant reductions in the subsidy paid or received; the exceptions are NRH, CSH and EU, very small classes (Schedule B6-4, line 44).

PROPOSED RATES

Q. Please identify and describe the exhibits that show FPFTY sales and revenue at proposed rates.

A. Schedule B6 shows the same information as Schedule B, with an additional column showing distribution revenue at "PROPOSED Rates" for FPFTY 2026. The information in this column is from Schedule B6-1, which is carried forward from Schedule B6-2. Schedule B6-2 summarizes the detailed computations of billing units times proposed rates, presented on Schedule B6-3.

Q. Did you prepare a schedule that summarizes the present and proposed rates?

A. Yes. Schedule B7 presents the present and proposed rates for each rate class.

Q. Did you compare the amounts that typical customers in each rate class would pay under the present and proposed rates?

A. Yes. Schedule B8 compares the amounts that customers in each rate class with a range of usage levels would pay in the FPFTY, both at present rates and proposed rates. The schedule presents a total bill comparison (i.e., including GSSR). Schedule B8-1 presents the comparisons for distribution-only comparison (i.e., excluding GSSR).

Schedule B8-2 presents the total bill comparison using the GSSR that is expected to take effect on June 1, 2025.

Q. Did you prepare a schedule showing the number of customers whose bills would increase under the proposed rates?

A. Yes. Schedule B5 presents that information.

Q. What were the overall goals for rate design?

A. The goals of rate design for each class were to produce the target revenue, to align the rates more closely with costs, to stabilize revenue for the utility and costs for customers and to mitigate extreme impacts on most customers.

Q. How did you compute the proposed rates for RS?

A. For RS, the As-filed monthly charge was increased from $12.00 to $16.50. The balance of the class revenue target is proposed to be recovered in the volumetric kWh charge.

The proposed monthly charge is less than the customer-related costs typically included, based on the ACOS ($17.59, Schedule E1-C, line 25).

Q. How did you compute the proposed rates for RSAE?

A. For RSAE, customer-related costs typically included are the same as for RS ($17.59, Schedule E1-C, line 25). Therefore, the monthly charge is proposed to be the same as RS, $16.50, and the balance of the class revenue target is proposed to be recovered in the volumetric kWh charge.

Q. How did you compute the proposed rates for NRS and NRH?

A. For NRS and NRH, customer-related costs typically included are the same as for RS ($17.59, Schedule E1-C, line 25). Therefore, the monthly charge for each is proposed to be the same as RS, $16.50, and the balance of the revenue target for each is proposed to be recovered in the respective volumetric kWh charges.

Q. How did you compute the proposed rates for CS?

A. The proposed monthly charge for CS is $32.03, the same as at present. The customer-related costs typically included, based on the ACOS are $26.35 (Schedule E1-C, line 25). However CS has a minimum demand of 7 kW and demand-related costs are $25.85 per kW-month (Schedule E1-B, line 6). The proposed demand charge was increased by 40%,

approximately equal to the class revenue increase. The balance of the class revenue target is proposed to be recovered in the volumetric kWh charge.

Q. How did you compute the proposed rates for CSH?

A. The proposed monthly charge for CSH is $45.81, the same as at present. The customer-related costs typically included, based on the ACOS are $26.35 (Schedule E1-C, line 25). However CSH has a minimum demand of 7 kW and demand-related costs are $26.01 per kW-month (Schedule E1-B, line 6). The balance of the class revenue target is proposed to be recovered in the volumetric kWh charge.

Q. How did you compute the proposed rates for IS?

A. The proposed monthly charge for IS of $150.00. The customer-related costs typically included, based on the ACOS are $71.80 (Schedule E1-C, line 25). However IS has a minimum demand of 50 kW and demand-related costs are $21.64 per kW-month (Schedule E1-B, line 6). The proposed demand charge and the proposed Block 2 kWh charge were each increased by 40%, approximately equal to the class revenue increase. The balance of the class revenue target is proposed to be recovered in the Block 1 volumetric kWh charge.

Q. How did you compute the proposed rates for MSL and POL?

A. For each lamp under MSL and POL, the proposed rates were changed by the same percentage as the overall revenue change for the respective class.

Q. How did you compute the proposed rates for EU?

A. The kWh charge for EU was increased to produce the revenue target for the class.

Q. Do the proposed rates produce the targeted revenues?

A. Yes. Schedule B6-3, line 38, demonstrates that the proposed rates will produce total distribution revenue in FPFTY 2026 of $9,301,000. This amount (plus a rounding adjustment) equals the total distribution revenue requirement (not including Other revenue), shown on Schedule C1, line 7.

Q. Does this conclude your Direct Testimony?

A. Yes.

BEFORE

THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	**:**	
	:	
v.	**:**	**Docket No. R-2025-_____**
	:	
Wellsboro Electric Company of Lewisburg, PA	**:**	

EXHIBITS

OF

HOWARD S. GORMAN

ON BEHALF OF

WELLSBORO ELECTRIC COMPANY OF LEWISBURG, PA

APRIL 30, 2025

RESUME OF
HOWARD S. GORMAN

SUMMARY

Mr. Gorman has more than 35 years of experience in the energy industry, including 25 years in rate and regulatory proceedings. His areas of expertise include embedded class cost of service studies, marginal cost studies, revenue allocation, rate design and revenue requirements, for both electric and gas utilities. He has testified as an expert witness before the Massachusetts Department of Public Utilities, New Hampshire Public Utilities Commission, New Jersey Board of Public Utilities, New York State Public Service Commission, Ontario Energy Board, Pennsylvania Public Utility Commission and Rhode Island Public Utilities Commission. Mr. Gorman also has experience in financial modeling, financial analysis and forecasting and treasury and financial management.

PROFESSIONAL EMPLOYMENT

2010 - Present HSG Group, Inc.
- *President*

1997 - 2010 Black & Veatch Corporation (R.J. Rudden Associates, Inc. before 2005)
- *Principal Consultant*

1995 - 1997 Independent Consultant

1987 – 1995 Trigen Energy Corporation
- 1987-1993- *Corporate Controller; Trigen was formed in 1987*
- 1993-1995- *Treasurer; Trigen had IPO with NYSE listing in 1994*

1982 - 1987 Coleco Industries, Inc.
- *Director, Treasury*

1976 - 1979 Touche Ross & Co.
- *Staff Accountant*

PROFESSIONAL EXPERIENCE

Utility Accounting and Costing

Mr. Gorman has performed numerous class cost of service studies, and has developed and supported revenue requirements, revenue allocation, rate designs and marginal cost studies, in rate cases before regulatory commissions in several jurisdictions, for electric and gas utilities. These assignments included developing test year data and rate year forecasts, establishing cost causality, selecting and developing allocators and analyzing customer impacts and policy considerations

Energy Project Analysis and Financing

Mr. Gorman has negotiated and completed transactions including construction and term loans, tax-exempt bonds, taxable bonds, subordinated debt and asset-backed (receivables and inventory) revolving credit facilities. He has worked successfully with lenders and borrowers to source and structure transactions, and was instrumental in negotiating loan documents and in designing power sale and supply procurement contracts to be financed. Mr. Gorman has performed financial analyses of energy-related assets, including electric and gas distribution companies, power plants and transmission operators. These analyses included development of cash flows and financial statements based on both regulatory and accounting presentations, and included review of assumptions, analysis of data, modeling and forecasting, sensitivity testing and stress testing.

Accounting and Financial Management

As controller of Trigen Energy Corporation, Mr. Gorman built the finance and accounting function; developed reports, procedures and management tools; and managed subsidiary controllers across North America, including an IPO with NYSE listing. He managed the corporate insurance portfolios and the benefit plans for Trigen Energy Corporation and for Coleco Industries, and has managed interest rate and currency forward contracts for the purpose of managing risk.

PUBLICATIONS AND PRESENTATIONS

"What Wall Street Needs From FERC," published in R. J. Rudden Financial, LLC's *Energy Capital Markets Report*, September 2002

"A Balanced Look at Balance Sheets," published in R.J. Rudden Financial, LLC's *Energy Capital Markets Report*, June 2002

"Assessment of Retail Choice Programs," presented at the American Gas Association Rate and Strategic Issues Committee Conference, March 2002

"The Remarkable Story on Enron," published in Scudder's *Annual End of Year Issue*, 2001

EDUCATION

New York University, B.S., Accounting, 1976
Harvard Business School, MBA, 1981

Relevant Projects			
Jurisdiction	**Docket**	**Client**	**Subject Matter**
Federal Energy Regulatory Commission 2024	ER24-2795-000, ER24-2796-000	Massachusetts / Nantucket Electric	Electric revenue requirement and rate design for Energy Storage Systems
New York 2024	24-E-0322	Niagara Mohawk (Gas)	Gas class cost of service; revenue allocation; rate design; marginal cost
New York 2024	24-G-0323	Niagara Mohawk (Electric)	Electric class cost of service; revenue allocation; rate design; marginal cost
Pennsylvania 2024	R-2024-3046523	Duquesne Light	Electric class cost of service; revenue allocation; rate design; special study
Massachusetts 2023	DPU 23-150	Massachusetts / Nantucket Electric	Electric class cost of service; revenue allocation; rate design
New Jersey 2024	GR24020158	Elizabethtown Gas.	Gas class cost of service; revenue allocation; rate design
Massachusetts 2023	DPU 23-150	Massachusetts / Nantucket Electric	Electric class cost of service; revenue allocation; rate design
New York 2023	23-G-0227	Valley Energy, Inc.	Gas revenue requirements, rate design
New York 2023	23-G-0225 /02260	Brooklyn Union Gas / KeySpan Gas East	Gas class cost of service; revenue allocation; rate design; marginal cost
Pennsylvania 2022	R-2022-3032369	Citizens' Electric of Lewisburg, PA	Electric revenue requirements, class cost of service, revenue allocation, rate design
Pennsylvania 2022	R-2022-3032300	Valley Energy, Inc.	Gas revenue requirements, rate design
Pennsylvania 2021	R-2021-3024060	Vicinity Energy Philadelphia	Steam system revenue requirements; sales forecast (formerly Veolia)
Pennsylvania 2021	R-2021-3024750	Duquesne Light	Electric class cost of service; revenue allocation; rate design
New York 2020	20-G-0381	Niagara Mohawk (Gas)	Gas class cost of service; revenue allocation; rate design; marginal cost
New York 2020	20-E-0380	Niagara Mohawk (Electric)	Electric class cost of service; revenue allocation; rate design; marginal cost
Pennsylvania 2019	R-2019-3008212	Citizens' Electric of Lewisburg, PA	Electric revenue requirements, class cost of service, revenue allocation, rate design
Pennsylvania 2019	R-2019-3008208	Wellsboro Electric Company	Electric revenue requirements, class cost of service, revenue allocation, rate design
Pennsylvania 2019	R-2019-3008209	Valley Energy, Inc.	Gas revenue requirements, rate design
New York 2019	19-G-0309 /0310	Brooklyn Union Gas / KeySpan Gas East	Gas class cost of service; revenue allocation; rate design; marginal cost
Massachusetts 2018	DPU 18-150	Massachusetts / Nantucket Electric	Electric class cost of service; revenue allocation; rate design; marginal cost Monthly Minimum Reliability Contribution
Pennsylvania 2018	R-2018-30000124	Duquesne Light	Electric class cost of service; revenue allocation; rate design

Relevant Projects			
Rhode Island 2017	RIPUC 4770	Narragansett Electric	Electric class cost of service; revenue allocation; rate design
Pennsylvania 2017	R-2017-2593142	Veolia Energy Philadelphia	Steam system revenue requirements; sales forecast
New York 2017	17-G-0239	Niagara Mohawk (Gas)	Gas class cost of service; revenue allocation; rate design; marginal cost
New York 2017	17-E-0238	Niagara Mohawk (Electric)	Electric class cost of service; revenue allocation; rate design; marginal cost
Pennsylvania 2016	R-2016-2531550	Citizens' Electric of Lewisburg, PA	Electric revenue requirements, class cost of service, revenue allocation, rate design
Pennsylvania 2016	R-2016-2531551	Wellsboro Electric Company	Electric revenue requirements, class cost of service, revenue allocation, rate design
New Hampshire 2016	DE 16-383	Granite State Electric	Electric revenue requirement
New York 2016	16-G-0058 /0059	Brooklyn Union Gas / KeySpan Gas East	Gas class cost of service; revenue allocation; rate design; marginal cost
Massachusetts 2015	DPU 15-155	Massachusetts / Nantucket Electric	Marginal cost
New York 2015	15-E-0184	Jamestown Board of Public Utilities	Electric revenue requirements
New Hampshire 2015	DE14-180	Energy North Natural Gas	Gas revenue requirements
New York 2014	14-E-0035	Village of Freeport	Electric revenue requirements; sales forecast; rate design
Pennsylvania 2014	R-2013-2386293	Veolia Energy Philadelphia	Steam system revenue requirements and sales forecast
Pennsylvania 2014	R-2013-2372129	Duquesne Light	Electric class cost of service; revenue allocation; rate design
New Hampshire 2013	DE13-063	Granite State Electric	Electric class cost of service (marginal cost); revenue allocation; rate design
Ontario 2013, 2012, 2010, 2009, 2008, 2006, 2005	EB-2005-0378 et al	Hydro One Networks Inc.	Electric Transmission and Distribution cost allocation; OH capitalization rates
Ontario 2006-2013	EB-2007-0905 et al	Ontario Power Generation	Electric cost allocation methodology (2013, 2010, 2006)
New York 2012	12-E-0201	Niagara Mohawk (Electric)	Electric class cost of service; revenue allocation
Rhode Island 2012	RIPUC 4323	Narragansett Electric	Electric class cost of service
New York 2011	11-E-0590	Village of Rockville Centre	Electric revenue requirements; rate design; sales forecast
New York 2011	11-G-0142	Chautauqua Utilities, Inc.	Gas revenue requirements, rate design
Pennsylvania 2010	R-2010-2179522	Duquesne Light	Electric class cost of service; revenue allocation; rate design

Relevant Projects			
Pennsylvania 2010	R-2010-2172662	Wellsboro Electric	Electric revenue requirements, class cost of service, revenue allocation, rate design
Pennsylvania 2010	R-2010-2172665	Citizens' Electric of Lewisburg, PA	Electric revenue requirements, class cost of service, revenue allocation, rate design
Pennsylvania 2010	R-2010-2174470	Valley Energy, Inc.	Gas revenue requirements, rate design
Pennsylvania 2010	R-2010-2161592	PECO Energy (Gas)	Gas class cost of service; revenue allocation; rate design
Pennsylvania 2010	R-2010-2161575	PECO Energy (Electric)	Electric class cost of service; revenue allocation; rate design
New York 2010	10-E-0050	Niagara Mohawk (Electric)	Electric class cost of service
New York 2009	09-E-0862	Jamestown Board of Public Utilities	Electric revenue requirements
Pennsylvania 2009, 2006, 2002, 2001	R-2139884 R-00061931 M-00021612 R- 00017034 R- 00006042	Philadelphia Gas Works	Gas class cost of service; revenue allocation; rate design; unbundling; fixed costs recovery
Rhode Island 2009	RIPUC 4065	Narragansett Electric	Electric class cost of service; revenue allocation; rate design
Massachusetts 2009	DPU 09-39	Massachusetts / Nantucket Electric	Electric revenue requirements; class cost of service; revenue allocation; rate design
Pennsylvania 2008	R-2008-2028394	PECO Energy (Gas)	Gas class cost of service; revenue allocation; rate design
Pennsylvania 2007	R-00072350	Wellsboro Electric	Electric revenue requirements; rate design
Pennsylvania 2007	R-00072348	Citizens' Electric of Lewisburg, PA	Electric revenue requirements; rate design
Pennsylvania 2007	R-00072349	Valley Energy, Inc.	Gas revenue requirements; rate design
New York 2006	06-E-0911	Village of Freeport	Electric revenue requirements; rate design
Pennsylvania 2006	R-00061346	Duquesne Light	Electric class cost of service; revenue allocation; rate design
New York 2003	03-E-1568	Village of Rockville Centre	Electric revenue requirements; rate design; sales forecast
New Jersey 2002	ER02080506, ER02050303 et al	AmeriSteel (intervenor)	Electric cost allocation and rate design; industrial rates

A

Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026
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6	B1-1	Billing Units, Rates And Revenue At Present Rates	Historic Year 2024
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Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026
INDEX TO SCHEDULES

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B

Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026

Operating Revenues Under Present Rates
12/31/2024, 12/31/2025 and 12/31/2026

Answer to 52 Pa. Code 53.52 b[2]

Line	Customer Type	HY 2024 Total Revenue- Present Rates	HY 2024 Distribution Only	Present Rates FTY 2025 Distribution Only	Present Rates FPFTY 2026 Distribution Only
		B1		B2-1	B3-1
1	Residential	$6,829,521	$3,190,200	$3,388,802	$3,395,335
2	Commercial and Industrial	5,657,570	2,642,167	2,887,490	2,902,837
3	Lighting	100,851	95,243	94,867	94,867
4	Sales for resale	17,863	8,957	8,957	8,957
5		12,605,805	5,936,568	6,380,115	6,401,996
6					
7	Forfeited Discounts	28,860	28,860	31,016	31,122
8	Rent from Electric Property	266,738	266,738	266,738	273,619
9	Other electric revenue	22,899	22,899	22,899	22,899
10	Sales Tax, STAS				
11	Unbilled	234,090			
12	Adjustments				
13	**Total Operating Revenues**	$13,158,392	$6,255,065	$6,700,768	$6,729,636
14	*Financials*	*$13,158,392*			
15	kWh				
16	Residential	41,774,098	41,774,098	45,123,694	45,210,554
17	Commercial and Industrial	54,875,548	54,875,548	58,839,950	60,548,647
18	Lighting	267,068	267,068	267,068	0
19	Sales for resale	102,572	102,572	102,572	102,572
20		97,019,287	97,019,287	104,333,284	105,861,774
21					

B1

Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026

Summary Of Electric Sales, Customers And Revenue At Present Rates
Historic Year 2024

Line	Rate Class	Sales (kWh)	Average Customers	Revenue - Present Rates: Fixed Customer Charge	Variable Distribution-Energy	Variable Distribution-Demand	Distribution Total	GSSR	STAS	Total Revenue
1										
2	Residential Customers									
3	Schedule 1- RS	41,448,363	5,130	$738,672	$2,430,532	$0	$3,169,204	$3,611,216	($697)	$6,779,723
4	Schedule 2- RSAE	325,735	30	4,296	16,700	0	20,996	28,807	(5)	49,799
5		41,774,098	5,160	742,968	2,447,232	0	3,190,200	3,640,023	(702)	6,829,521
6										
7	Commercial and Industrial Customers									
8	Schedule 3- NRS	3,958,829	908	133,112	302,059	0	435,171	335,804	(72)	770,904
9	Schedule 3- NRH	10,826	1	183	917	0	1,100	954	(0)	2,054
10	Schedule 4- CS	26,289,234	381	146,473	596,240	661,390	1,404,103	1,700,741	(319)	3,104,525
11	Schedule 4- CSH	6,480	1	550	429	0	979	557	(0)	1,536
12	Schedule 5- IS	24,610,180	13	13,260	184,668	602,886	800,814	977,913	(175)	1,778,551
13		54,875,548	1,304	293,579	1,084,313	1,264,276	2,642,167	3,015,968	(565)	5,657,570
14										
15	Schedule 6- Municipal Street Lights	64,798	Not shown	0	13,576	0	13,576	5,609		19,185
16	Schedule 7- Private Outdoor Lights	202,270	Not shown	0	81,667	0	81,667	0	(2)	81,665
17	Lighting	267,068	0	0	95,243	0	95,243	5,609	(2)	100,851
18										
19	Schedule 8- Exchange Utility	102,572	4	0	8,957	0	8,957	8,907		17,863
20										
21	TOTAL	97,019,287	6,468	$1,036,547	$3,635,745	$1,264,276	$5,936,568	$6,670,507	($1,270)	$12,605,805

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Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026
Billing Units, Rates And Revenue At Present Rates
Historic Year 2024

Line		Sch. 1- RS	Sch. 2- RSAE	Sch. 3- NRS	Sch. 3- NRH	Sch. 4- CS	Sch. 4- CSH	Sch. 5- IS	Sch. 6- MSL	Sch. 7- POL	Sch. 8- EU	Total
1		**BILLING UNITS**										
2	kWh Sales	41,448,363	325,735	3,958,829	10,826	26,289,234	6,480	24,610,180	64,798	202,270	102,572	97,019,287
3												
4	Number of Bills	61,556	358	10,893	15	4,573	12	156			48	77,611
5	Average Monthly Bills	5,130	30	908	1	381	1	13			4	6,468
6												
7		**Annual Billing Units- Public Lighting and Street Lighting HY 2024**										
8	MV 20000 lumens								12	12		24
9	LED 50 OH								1,776	5,104		6,880
10	LED 50 UG								0	0		0
11	LED 50 UG Col								0	0		0
12	LED 70 OH								1,307	4,365		5,672
13	LED 70 UG								0	0		0
14	LED 140 OH								0	24		24
15	LED 140 UG								0	0		0
16									3,095	9,505		12,600
17		**RATES AND CHARGES**										
18		**Tariff Rates**										
19	Customer Charge	$12.00	$12.00	$12.22	$12.22	$32.03	$45.81	$85.00				
20												
21	Energy Block 1	$0.058640	$0.051270	$0.076300	$0.084690	$0.022680	$0.066280	$0.020780	$10.76	$8.81	$0.08732	
22	Energy Block 2							$0.001300	$4.12	$8.33		
23									$11.06	$11.06		
24									$16.03	$16.03		
25									$4.69	$8.89		
26									$11.62	$11.62		
27									$5.81	$10.02		
28									$12.75	$12.75		
29												
30	Block 1 kWh = Demand X							130				
31	Demand Block 1					$6.60		$10.00				
32												
33		**COMPUTATION OF REVENUE**										
34	Customer Charge Revenue	738,672	4,296	133,112	183	146,473	550	13,260	0	0	0	1,036,547
35												
36	Distribution kWh Revenue	2,430,532	16,700	302,059	917	596,240	429	184,668	13,576	81,667	8,957	3,635,745
37	Distribution Demand Revenu	0	0	0	0	661,390	0	602,886	0	0	0	1,264,276
38	*Total Distribution Revenue*	2,430,532	16,700	302,059	917	1,257,630	429	787,554	13,576	81,667	8,957	4,900,021

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Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026
Billing Units, Rates And Revenue At Present Rates
Historic Year 2024

Line		Sch. 1- RS	Sch. 2- RSAE	Sch. 3- NRS	Sch. 3- NRH	Sch. 4- CS	Sch. 4- CSH	Sch. 5- IS	Sch. 6- MSL	Sch. 7- POL	Sch. 8- EU	Total
39	**Distribution Revenue**	$3,169,204	$20,996	$435,171	$1,100	$1,404,103	$979	$800,814	$13,576	$81,667	$8,957	$5,936,568
40	**STAS Revenue**	(697)	(5)	(72)	(0)	(319)	(0)	(175)	(2)			(1,270)
41	**Generation Revenue**	3,611,216	28,807	335,804	954	1,700,741	557	977,913	5,609	0	8,907	6,670,507
42	**Total Revenue**	6,779,723	49,799	770,904	2,054	3,104,525	1,536	1,778,551	19,183	81,667	17,863	12,605,805
43												
44		**BILLING UNITS- DETAIL**										
45	Block 1 kWh Sales	41,448,363	325,735	3,958,829	10,826	26,289,234	6,480	7,837,515	64,798	202,270	102,572	80,246,622
46	Block 2 kWh Sales							16,772,665				16,772,665
47	Block 1 kW Demand Computed					100,211		59,872				
48	Block 1 kW Demand Adjustment							417				
49	Block 1 kW Demand					100,211		60,289				160,499

Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026

Summary Of Electric Sales, Customers And Revenue At Present Rates
Future Test Year 2025

Line	Rate Class	Sales (kWh)	Average Customers	Revenue - Present Rates			
				Fixed Customer Charge	Variable Distribution-Energy	Variable Distribution-Demand	Distribution Total
1							
2	Residential Customers						
3	Schedule 1- RS	44,725,913	5,149	$741,480	$2,622,728	$0	$3,364,208
4	Schedule 2- RSAE	397,781	29	4,200	20,394	0	24,594
5		45,123,694	5,178	745,680	2,643,122	0	3,388,802
6							
7	Commercial and Industrial Customers						
8	Schedule 3- NRS	4,681,726	928	136,106	357,216	0	493,322
9	Schedule 3- NRH	6,256	1	147	530	0	676
10	Schedule 4- CS	28,760,218	388	149,132	652,282	712,800	1,514,213
11	Schedule 4- CSH	7,216	1	550	478	0	1,028
12	Schedule 5- IS	25,384,534	13	13,600	201,050	663,600	878,250
13		58,839,950	1,332	299,534	1,211,555	1,376,400	2,887,490
14							
15	Schedule 6- Municipal Street Lights	64,798	Not shown	0	13,496	0	13,496
16	Schedule 7- Private Outdoor Lights	202,270	Not shown	0	81,371	0	81,371
17	Lighting	267,068	0	0	94,867	0	94,867
18							
19	Schedule 8- Exchange Utility	102,572	4	0	8,957	0	8,957
20							
21	TOTAL	104,333,284	6,514	$1,045,214	$3,958,501	$1,376,400	$6,380,115

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Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026
Billing Units, Rates And Revenue At Present Rates
Future Test Year 2025

Line		Sch. 1- RS	Sch. 2- RSAE	Sch. 3- NRS	Sch. 3- NRH	Sch. 4- CS	Sch. 4- CSH	Sch. 5- IS	Sch. 6- MSL	Sch. 7- POL	Sch. 8- EU	Total
1						**BILLING UNITS**						
2	kWh Sales	44,725,913	397,781	4,681,726	6,256	28,760,218	7,216	25,384,534	64,798	202,270	102,572	104,333,284
3												
4	Number of Bills	61,790	350	11,138	12	4,656	12	160			48	78,166
5	Average Monthly Bills	5,149	29	928	1	388	1	13			4	6,514
6												
7		**Annual Billing Units- Public Lighting and Street Lighting, Future Test Year 2025**										
8	MV 20000 lumens											
9	LED 50 OH								1,788	5,064		6,852
10	LED 50 UG											
11	LED 50 UG Col											
12	LED 70 OH								1,307	4,381		5,688
13	LED 70 UG											
14	LED 140 OH									24		24
15	LED 140 UG											
16									3,095	9,469		12,564
17		**RATES AND CHARGES**										
18		**Tariff Rates**										
19	Customer Charge	$12.00	$12.00	$12.22	$12.22	$32.03	$45.81	$85.00				
20												
21	Energy Block 1	$0.05864	$0.05127	$0.07630	$0.08469	$0.02268	$0.06628	$0.02078	$10.76	$8.81	$0.08732	
22	Energy Block 2							$0.00130	$4.12	$8.33		
23									$11.06	$11.06		
24									$16.03	$16.03		
25									$4.69	$8.89		
26									$11.62	$11.62		
27									$5.81	$10.02		
28									$12.75	$12.75		
29												
30	Block 1 kWh = Demand X							130				
31	Demand Block 1					$6.60		$10.00				
32												

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Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026
Billing Units, Rates And Revenue At Present Rates
Future Test Year 2025

Line		Sch. 1- RS	Sch. 2- RSAE	Sch. 3- NRS	Sch. 3- NRH	Sch. 4- CS	Sch. 4- CSH	Sch. 5- IS	Sch. 6- MSL	Sch. 7- POL	Sch. 8- EU	Total
33		**COMPUTATION OF REVENUE**										
34	Customer Charge Revenue	741,480	4,200	136,106	147	149,132	550	13,600	0	0	0	1,045,214
35												
36	Distribution kWh Revenue	2,622,728	20,394	357,216	530	652,282	478	201,050	13,496	81,371	8,957	3,958,501
37	Distribution Demand Revenue					712,800		663,600				1,376,400
38	*Volumetric Distribution Reve*	2,622,728	20,394	357,216	530	1,365,082	478	864,650	13,496	81,371	8,957	5,334,901
39	**Total Distribution Revenue**	$3,364,208	$24,594	$493,322	$676	$1,514,213	$1,028	$878,250	$13,496	$81,371	$8,957	$6,380,115
40		*3,357,674*	*24,594*	*487,955*		*1,505,471*		*878,250*				
41		**KWh BILLING UNITS- DETAIL**										
42	Average Customers 2024	5,139	29	918	1	384	1	13	0		4	6,490
43	Customers added (lost)	10		10		4						24
44	Forecast Customers 2025	5,149	29	928	1	388	1	13	0	0	4	6,514
45	Block 1 kWh Sales	44,725,913	397,781	4,681,726	6,256	28,760,218	7,216	8,626,800	64,798	202,270	102,572	87,575,550
46	Block 2 kWh Sales							16,757,734				16,757,734
47												
48	Source:	Prior Study	Prior Study	Prior Study	Historic	Prior Study	Historic	Prior Study	Historic	Historic	Historic	
49	Forecast kWh 2025 at 2024 Cus	44,639,052	397,781	4,631,285	6,256	28,463,721	7,216	25,384,534	64,798	202,270	102,572	103,899,486
50	Customers Average 2024	5,139	29	918	1	384	1	13			4	6,490
51	Annual Use Per Customer	8,686	13,638	5,044	6,256	74,124	7,216	1,903,840			25,643	
52												
53	Block 1 kW Demand- Same as 2024					108,000		66,360				174,360

Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026

Summary Of Electric Sales, Customers And Revenue At Present Rates
Fully Projected Future Test Year 2026

Line	Rate Class	Sales (kWh)	Average Customers	Revenue - Present Rates			
				Fixed Customer Charge	Variable Distribution-Energy	Variable Distribution-Demand	Distribution Total
1							
2	Residential Customers						
3	Schedule 1- RS	44,812,773	5,159	$742,920	$2,627,821	$0	$3,370,741
4	Schedule 2- RSAE	397,781	29	4,200	20,394	0	24,594
5		45,210,554	5,188	747,120	2,648,215	0	3,395,335
6							
7	Commercial and Industrial Customers						
8	Schedule 3- NRS	4,732,166	938	137,573	361,064	0	498,637
9	Schedule 3- NRH	6,256	1	147	530	0	676
10	Schedule 4- CS	29,056,715	392	150,669	659,006	712,800	1,522,475
11	Schedule 4- CSH	7,216	1	550	478	0	1,028
12	Schedule 5- IS	26,746,293	13	13,600	202,820	663,600	880,020
13		60,548,647	1,346	302,538	1,223,899	1,376,400	2,902,837
14							
15	Schedule 6- Municipal Street Lights	0	Not shown	0	13,496	0	13,496
16	Schedule 7- Private Outdoor Lights	0	Not shown	0	81,371	0	81,371
17	Lighting	0	0	0	94,867	0	94,867
18							
19	Schedule 8- Exchange Utility	102,572	4	0	8,957	0	8,957
20							
21	TOTAL	105,861,774	6,538	$1,049,658	$3,975,938	$1,376,400	$6,401,996

B3-1

Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026
Billing Units, Rates And Revenue At Present Rates
Fully Projected Future Test Year 2026

Line		Sch. 1- RS	Sch. 2- RSAE	Sch. 3- NRS	Sch. 3- NRH	Sch. 4- CS	Sch. 4- CSH	Sch. 5- IS	Sch. 6- MSL	Sch. 7- POL	Sch. 8- EU	Total
1		**BILLING UNITS**										
2	kWh Sales	44,812,773	397,781	4,732,166	6,256	29,056,715	7,216	26,746,293	0	0	102,572	105,861,774
3												
4	Number of Bills	61,910	350	11,258	12	4,704	12	160			48	78,454
5	Average Monthly Bills	5,159	29	938	1	392	1	13			4	6,538
6												
7		**Annual Billing Units- Public Lighting and Street Lighting, Fully Projected Future Test Year 2026**										
8	MV 20000 lumens											
9	LED 50 OH								1,788	5,064		6,852
10	LED 50 UG											
11	LED 50 UG Col											
12	LED 70 OH								1,307	4,381		5,688
13	LED 70 UG											
14	LED 140 OH									24		24
15	LED 140 UG											
16									3,095	9,469		12,564
17		**RATES AND CHARGES**										
18		**Tariff Rates**										
19	Customer Charge	$12.00	$12.00	$12.22	$12.22	$32.03	$45.81	$85.00				
20												
21	Energy Block 1	$0.05864	$0.05127	$0.07630	$0.08469	$0.02268	$0.06628	$0.02078	$10.76	$8.81	$0.08732	
22	Energy Block 2							$0.00130	$4.12	$8.33		
23									$11.06	$11.06		
24									$16.03	$16.03		
25									$4.69	$8.89		
26									$11.62	$11.62		
27									$5.81	$10.02		
28									$12.75	$12.75		
29												
30	Block 1 kWh = Demand X							130				
31	Demand Block 1					$6.60		$10.00				
32												
33		**COMPUTATION OF REVENUE**										
34	Customer Charge Revenue	742,920	4,200	137,573	147	150,669	550	13,600	0	0	0	1,049,658
35												
36	Distribution kWh Revenue	2,627,821	20,394	361,064	530	659,006	478	202,820	13,496	81,371	8,957	3,975,938
37	Distribution Demand Revenue					712,800		663,600				1,376,400

B3-1

Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026
Billing Units, Rates And Revenue At Present Rates
Fully Projected Future Test Year 2026

Line		Sch. 1- RS	Sch. 2- RSAE	Sch. 3- NRS	Sch. 3- NRH	Sch. 4- CS	Sch. 4- CSH	Sch. 5- IS	Sch. 6- MSL	Sch. 7- POL	Sch. 8- EU	Total
38	*Volumetric Distribution Rever*	2,627,821	20,394	361,064	530	1,371,806	478	866,420	13,496	81,371	8,957	5,352,338
39	**Total Distribution Revenue**	$3,370,741	$24,594	$498,637	$676	$1,522,475	$1,028	$880,020	$13,496	$81,371	$8,957	$6,401,996
40		*3,357,674*	*24,303*	*490,190*		*1,507,533*		*880,700*				
41		**BILLING UNITS- DETAIL**										
42	Forecast Customers 2025	5,149	29	928	1	388	1	13			4	6,514
43	Customers added (lost)	10		10		4						24
44	Forecast Customers 2026	5,159	29	938	1	392	1	13	0	0	4	6,538
45	Block 1 kWh Sales	44,812,773	397,781	4,732,166	6,256	29,056,715	7,216	8,626,800	0	0	102,572	87,742,280
46	Block 2 kWh Sales							18,119,493				18,119,493
47								26,746,293				
48												
49												
50	From Sch B2-1											
51	Annual Use Per Customer	8,686	13,638	5,044	6,256	74,124	7,216	1,903,840			25,643	
52												
53	Block 1 kW Demand- Same as 2024					108,000		66,360				174,360
54												

B4

Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026

Bill Analysis- Revenues Under Present Rates
Historic Year 2024

B1

Line	Customer Type	Bill Analysis Revenue	GSSR	STAS	Distribution plus GSSR	Unbilled and GSSR Over/ (Under)	Other	Revenue Computed	Revenue per 2024 Financial Statements
1	Residential	$3,190,200	$3,640,023	($702)	$6,829,521	$157,897		$6,987,418	$6,987,418
2	Commercial and Industrial	2,642,167	3,015,968	(565)	5,657,570	157,635		5,815,205	5,815,205
3	Lighting	95,243	5,609	(2)	100,851	(81,649)		19,202	19,202
4	Exchange Utility	8,957	8,907	0	17,863	207		18,070	18,070
5		5,936,568	6,670,507	(1,270)	12,605,805	234,090	0	12,839,895	12,839,895
6									
7	Forfeited Discounts						28,860	28,860	28,860
8	Rent from Electric Property						266,738	266,738	266,738
9	Other electric revenue						22,899	22,899	22,899
10									
11		$5,936,568	$6,670,507	($1,270)	$12,605,805	$234,090	$318,497	$13,158,392	$13,158,392
12									

B5

Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026

Number of Customers Served Whose Bills Will be Increased
12/31/2024, 12/31/2025 and 12/31/2026
Answer to 52 Pa. Code 53.52 b[3]

Line	Customer Type	Total Customers 12/31/2024	Total Customers 12/31/2025	Total Customers 12/31/2026
1	Residential	5,160	5,178	5,188
2	Commercial and Industrial	1,304	1,332	1,346
3	Lighting	0	0	0
4	Exchange Utility	4	4	4
5	Total Customers Served	6,468	6,514	6,538
6				
7				
8				

B6

Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026

Operating Revenue Under Present Rates and Proposed Rates
12/31/2024, 12/31/2025 and 12/31/2026
Answer to 52 Pa. Code 53.52 b[4]

Line	Description	Total	Distribution Only			
		HY 2024 Total Revenue	HY 2024	FTY 2025 PRESENT Rates	FPFTY 2026 PRESENT Rates	FPFTY 2026 PROPOSED Rates
1	**Operating Revenues**	B	B	B	B	B6-1
2	Residential	$6,829,521	$3,190,200	$3,388,802	$3,395,335	$5,078,907
3	Commercial and Industrial	5,657,570	2,642,167	2,887,490	2,902,837	4,096,297
4	Lighting	100,851	95,243	94,867	94,867	113,787
5	Exchange Utility	17,863	8,957	8,957	8,957	12,171
6	Subtotal	12,605,805	5,936,568	6,380,115	6,401,996	9,301,162
7						
8	Forfeited Discounts	28,860	28,860	31,016	31,122	31,122
9	Rent from Electric Property	266,738	266,738	266,738	273,619	273,619
10	Other electric revenue	22,899	22,899	22,899	22,899	22,899
11	Annual Rates vs Present Rates					
12	Book to Bill difference	234,090				
13	Adjustments	0				
14	Total Operating Revenues	$13,158,392	$6,255,065	$6,700,768	$6,729,636	$9,628,802
15						
16	kWh					
17	Residential	41,774,098		45,123,694	45,210,554	
18	Commercial and Industrial	54,875,548		58,839,950	60,548,647	
19	Lighting	267,068		267,068	0	
20	Sales for resale	102,572		102,572	102,572	
21		97,019,287		104,333,284	105,861,774	

Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026

Summary Of Proposed Increase to Distribution Revenue
Fully Projected Future Test Year 2026

Line	Rate Class	Sales (kWh)	Average Customers	Distribution Total Present Rates	Distribution - Proposed Increase	Distribution Total Proposed Rates
1	Residential Customers	B3	B3	B3		B6-2
2	Schedule 1- RS	44,812,773	5,159	3,370,741	1,668,687	5,039,428
3	Schedule 2- RSAE	397,781	29	24,594	14,885	39,479
4	Schedule RS- Residential Service	45,210,554	5,188	3,395,335	1,683,572	5,078,907
5						
6	Commercial and Industrial Customers					
7	Schedule 3- NRS	4,732,166	938	498,637	236,099	734,736
8	Schedule 3- NRH	6,256	1	676	507	1,184
9	Schedule 4- CS	29,056,715	392	1,522,475	601,548	2,124,023
10	Schedule 4- CSH	7,216	1	1,028	771	1,799
11	Schedule 5- IS	26,746,293	13	880,020	354,535	1,234,556
12		60,548,647	1,346	2,902,837	1,193,460	4,096,297
13						
14	Schedule 6- Municipal Street Lights	0	Not shown	13,496	6,158	19,655
15	Schedule 7- Private Outdoor Lights	0	Not shown	81,371	12,761	94,132
16	Lighting	0	0	94,867	18,920	113,787
17						
18	Schedule 8- Exchange Utility	102,572	4	8,957	3,215	12,171
19						
20	TOTAL	105,861,774	6,538	$6,401,996	$2,899,166	$9,301,162

Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026

Summary Of Electric Sales, Customers And Revenue At Proposed Rates
Fully Projected Future Test Year 2026

Line	Rate Class	Sales (kWh)	Average Customers	Revenue - Proposed Rates			
				Fixed Customer Charge	Variable Distribution-Energy	Variable Distribution-Demand	Distribution Total
1	Residential Customers						
2	Schedule 1- RS	44,812,773	5,159	1,021,515	4,017,913	0	5,039,428
3	Schedule 2- RSAE	397,781	29	5,775	33,704	0	39,479
4	Schedule RS- Residential Service	45,210,554	5,188	1,027,290	4,051,617	0	5,078,907
5							
6	Commercial and Industrial Customers						
7	Schedule 3- NRS	4,732,166	938	185,757	548,979	0	734,736
8	Schedule 3- NRH	6,256	1	198	986	0	1,184
9	Schedule 4- CS	29,056,715	392	150,669	975,434	997,920	2,124,023
10	Schedule 4- CSH	7,216	1	550	1,249	0	1,799
11	Schedule 5- IS	26,746,293	13	24,000	281,516	929,040	1,234,556
12		60,548,647	1,346	361,174	1,808,163	1,926,960	4,096,297
13							
14	Schedule 6- Municipal Street Lights	0	0	0	19,655	0	19,655
15	Schedule 7- Private Outdoor Lights	0	Not shown	0	94,132	0	94,132
16	Lighting	0	0	0	113,787	0	113,787
17							
18	Schedule 8- Exchange Utility	102,572	4	0	12,171	0	12,171
19							
20	TOTAL	105,861,774	6,538	$1,388,464	$5,985,738	$1,926,960	$9,301,162

B6-3

Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026
Billing Units, Rates And Revenue At Proposed Rates
Fully Projected Future Test Year 2026

Line		Sch. 1- RS	Sch. 2- RSAE	Sch. 3- NRS	Sch. 3- NRH	Sch. 4- CS	Sch. 4- CSH	Sch. 5- IS	Sch. 6- MSL	Sch. 7- POL	Sch. 8- EU	Total
1						**BILLING UNITS**						
2	kWh Sales	44,812,773	397,781	4,732,166	6,256	29,056,715	7,216	26,746,293	0	0	102,572	105,861,774
3												
4	Number of Bills	61,910	350	11,258	12	4,704	12	160	0		48	78,454
5	Average Monthly Bills	5,159	29	938	1	392	1	13	0		4	6,538
6												
7						**Annual Billing Units- Public Lighting and Street Lighting**						
8	MV 20000 lumens								0	0		0
9	LED 50 OH								1,788	5,064		6,852
10	LED 50 UG								0	0		0
11	LED 50 UG Col								0	0		0
12	LED 70 OH								1,307	4,381		5,688
13	LED 70 UG								0	0		0
14	LED 140 OH								0	24		24
15	LED 140 UG								0	0		0
16									3,095	9,469		12,564
17						**RATES AND CHARGES**						
18						**Tariff Rates**						
19	Customer Charge	$16.50	$16.50	$16.50	$16.50	$32.03	$45.81	$150.00				Sch6 / Sch7 Lamps
20	Energy Block 1	$0.08966	$0.08473	$0.11601	$0.15758	$0.03357	$0.17313	$0.02881	$15.67	$10.19	$0.118660	MV 20000 lumens
21	Energy Block 2							$0.00182	$6.00	$9.64		LED 50 OH
22									$16.10	$12.79		LED 50 UG
23									$23.34	$18.54		LED 50 UG Col
24									$6.83	$10.28		LED 70 OH
25									$16.92	$13.44		LED 70 UG
26									$8.46	$11.59		LED 140 OH
27									$18.56	$14.75		LED 140 UG
28												
29	Demand Block 1					$9.24		$14.00				
30	Demand Block 2					140%		140%				
31												
32						**COMPUTATION OF REVENUE**						
33	Customer Charge Reven	1,021,515	5,775	185,757	198	150,669	550	24,000	0	0	0	1,388,464
34												
35	Distribution kWh Reven	4,017,913	33,704	548,979	986	975,434	1,249	281,516	19,655	94,132	12,171	5,985,738
36	Distribution Demand Revenue					997,920		929,040				1,926,960
37	*Total Distribution Rever*	4,017,913	33,704	548,979	986	1,973,354	1,249	1,210,556	19,655	94,132	12,171	7,912,698
38	**Total Revenue**	$5,039,428	$39,479	$734,736	$1,184	$2,124,023	$1,799	$1,234,556	$19,655	$94,132	$12,171	$9,301,162
39	Target Revenue	5,039,601	39,479	734,730	1,184	2,124,073	1,799	1,234,568	19,651	94,128	12,171	9,301,384
40						**BILLING UNITS- DETAIL**						
41	Block 1 kWh Sales	44,812,773	397,781	4,732,166	6,256	29,056,715	7,216	8,626,800	0	0	102,572	87,742,280
42	Block 2 kWh Sales							18,119,493				18,119,493
43												
44	Block 1 kW Demand					108,000		66,360				

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Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026
Proposed Revenue By Rate Class
Fully Projected Future Test Year 2026

Line	Account	Balance	RS	RSAE	NRS	NRH	CS	CSH	IS	MSL	POL	EU
	PRESENT RATES											
1	Distribution Revenue	6,401,996	3,370,741	24,594	498,637	676	1,522,475	1,028	880,020	13,496	81,371	8,957
2	Forfeited Disc / Other Rev	327,640	176,541	1,950	16,963	118	75,997	236	54,556	216	862	202
3	**Total Revenue**	6,729,636	3,547,282	26,544	515,600	794	1,598,472	1,264	934,576	13,712	82,233	9,159
4	Expenses	6,554,565	3,888,535	35,071	549,279	2,051	1,284,977	3,966	759,003	7,527	16,840	7,317
5	Net income	175,071	(341,253)	(8,527)	(33,679)	(1,256)	313,495	(2,702)	175,573	6,186	65,393	1,842
6	Rate Base	25,857,280	14,330,403	143,611	1,883,819	9,415	5,706,466	19,138	3,491,939	111,717	138,165	22,606
7	Return on Rate Base	0.68%	(2.38%)	(5.94%)	(1.79%)	(13.34%)	5.49%	(14.12%)	5.03%	5.54%	47.33%	8.15%
8	Relative Return	1.00 x	(3.52) x	(8.77) x	(2.64) x	(19.71) x	8.11 x	(20.85) x	7.43 x	8.18 x	69.90 x	12.03 x
9												
10	**FULLY ALLOCATED COST OF SERVICE**											
11	Distribution Revenue	9,301,384	5,442,633	50,786	759,020	3,135	1,871,891	6,187	1,110,768	19,546	27,675	9,743
12	Forfeited Disc / Other Revenue	327,640	176,541	1,950	16,963	118	75,997	236	54,556	216	862	202
13	Revenue Requirement	9,629,025	5,619,174	52,736	775,982	3,253	1,947,887	6,423	1,165,324	19,762	28,537	9,946
14												
15	Operating expenses	6,316,570	3,766,400	34,390	529,854	2,062	1,227,528	4,012	726,564	6,669	12,137	6,955
16	GRT	548,782	321,115	2,996	44,782	185	110,442	365	65,535	1,153	1,633	575
17	Income taxes	648,547	359,432	3,602	47,250	236	143,128	480	87,584	2,802	3,465	567
18	Net income	2,115,125	1,172,227	11,747	154,096	770	466,789	1,566	285,641	9,138	11,302	1,849
19	Return on Rate Base	8.18%	8.18%	8.18%	8.18%	8.18%	8.18%	8.18%	8.18%	8.18%	8.18%	8.18%
20	Revenue Increase Required	2,899,388	2,071,892	26,192	260,383	2,459	349,415	5,159	230,748	6,050	(53,695)	787
21	Revenue Increase %	43.08%	58.41%	98.67%	50.50%	309.58%	21.86%	408.12%	24.69%	44.12%	(65.30%)	8.59%
22												
23	**PROPOSED REVENUE ALLOCATION**											
24	Distribution Revenue	9,301,384	5,039,601	39,479	734,730	1,184	2,124,073	1,799	1,234,568	19,651	94,128	12,171
25	Other Revenue	327,640	176,541	1,950	16,963	118	75,997	236	54,556	216	862	202
26	Revenue Requirement	9,629,025	5,216,143	41,429	751,693	1,302	2,200,070	2,035	1,289,124	19,867	94,990	12,373
27												
28	Operating expenses	6,316,570	3,766,400	34,390	529,854	2,062	1,227,528	4,012	726,564	6,669	12,137	6,955
29	GRT	548,782	297,336	2,329	43,349	70	125,320	106	72,840	1,159	5,554	718
30	Income taxes	648,547	270,434	1,105	41,886	(195)	198,816	(489)	114,922	2,825	18,140	1,103
31	Net income	2,115,126	881,973	3,605	136,604	(635)	648,405	(1,595)	374,799	9,214	59,160	3,597
32	**Return on Rate Base**	**8.18%**	**6.15%**	**2.51%**	**7.25%**	**(6.75%)**	**11.36%**	**(8.33%)**	**10.73%**	**8.25%**	**42.82%**	**15.91%**
33	**Relative Return**	**1.00 x**	**0.75 x**	**0.31 x**	**0.89 x**	**(0.82) x**	**1.39 x**	**(1.02) x**	**1.31 x**	**1.01 x**	**5.23 x**	**1.95 x**
34	**Progress toward unity**		**95%**	**93%**	**97%**	**91%**	**95%**	**91%**	**95%**	**100%**	**94%**	**91%**
35												
36	**Proposed Distribution Increase**	**2,899,388**	**1,668,860**	**14,885**	**236,093**	**507**	**601,598**	**771**	**354,548**	**6,155**	**12,757**	**3,214**
37	**Revenue Increase %**	**45.3%**	**49.5%**	**60.5%**	**47.3%**	**75.0%**	**39.5%**	**75.0%**	**40.3%**	**45.6%**	**15.7%**	**35.9%**
38	Total Bill Revenue Increase (100% GSSR)	17.4%	21.7%	23.6%	24.7%	39.6%	13.9%	44.7%	10.2%	45.6%	15.7%	17.0%
39	Proposed Increase		49.51%	60.52%	47.35%	75.00%	39.51%	75.00%	40.29%	45.60%	15.68%	35.89%
40	% of Cost of Service	100%	93%	79%	97%	40%	113%	32%	111%	101%	333%	124%
41	**Subsidy given (received)**											
42	Present rates	(0)	(438,279)	(9,499)	(46,434)	(1,320)	274,858	(2,832)	151,930	5,429	64,457	1,689
43	Proposed revene allocation	0	(290,254)	(8,143)	(17,493)	(1,405)	181,616	(3,160)	89,158	75	47,858	1,748
44	**Reduction in subsidy**		**34%**	**14%**	**62%**	**(6%)**	**34%**	**(12%)**	**41%**	**99%**	**26%**	**(4%)**
45	Revenue Increase % Filed	19.5%	24.4%	28.1%	17.3%	28.8%	10.6%	28.6%	24.3%	1.2%	(19.9%)	25.8%
46	**Multiplier**	**0.951088**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**
47	**Relative increase**	**1.00 x**	**1.09 x**	**1.34 x**	**1.05 x**	**1.66 x**	**0.87 x**	**1.66 x**	**0.89 x**	**1.01 x**	**0.35 x**	**0.79 x**

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Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026

Summary Of Present And Proposed Rates
Fully Projected Future Test Year 2026

Line		Present Rates (excl GSSR)	Present Rates (incl GSSR present)	Proposed Rates (excl GSSR)	Proposed Rates (incl GSSR present)	Proposed Increase (excl GSSR)	Proposed Increase (incl GSSR present)
1	**Schedule RS- Residential Service**						
2	Customer Charge per Bill	$12.00	$12.00	$16.50	$16.50	37.5%	
3							
4	Energy Charge, per kWh- All	$0.058640	$0.15529	$0.089660	$0.18631	52.9%	20.0%
5	**Schedule RSAE- Residential Service All Electric**						
6	Customer Charge per Bill	$12.00	$12.00	$16.50	$16.50	37.5%	
7							
8	Energy Charge, per kWh- All	$0.051270	$0.14792	$0.084730	$0.18138	65.3%	22.6%
9	**Schedule NRS- Non-Residential Service**						
10	Customer Charge per Bill	$12.22	$12.22	$16.50	$16.50	35.0%	
11							
12	Energy Charge, per kWh- All	$0.076300	$0.17295	$0.116010	$0.21266	52.0%	23.0%
13	**Schedule NRH- Non-Residential Service Space Heating**						
14	Customer Charge per Bill	$12.22	$12.22	$16.50	$16.50	35.0%	
15							
16	Energy Charge, per kWh- All	$0.084690	$0.18134	$0.157580	$0.25423	86.1%	40.2%
17	**Schedule CS- Commercial Service (Minimum 7 kW)**						
18	Customer Charge per Bill	$32.03	$32.03	$32.03	$32.03	0.0%	
19							
20	Energy Charge, per kWh- All	$0.022680	$0.11933	$0.033570	$0.13022	48.0%	9.1%
21							
22	Demand Charge, per kW-Mth- All	$6.60	$6.60	$9.24	$9.24	40.0%	
23	**Schedule CSH- Commercial Service Space Heaters (Minimum 7 kW)**						
24	Customer Charge per Bill	$45.81	$45.81	$45.81	$45.81	0.0%	
25							
26	Energy Charge, per kWh- All	$0.066280	$0.16293	$0.173130	$0.26978	161.2%	65.6%
27	**Schedule IS- General Service (Minimum 2300 volts, 50 kW)**						
28	Customer Charge per Bill	$85.00	$85.00	$150.00	$150.00	76.5%	
29							
30	Energy Charge, per kWh						
31	First 130 kWh X Billed Demand kW	$0.02078	$0.11743	$0.02881	$0.12546	38.6%	6.8%
32	Additional kWh	$0.00130	$0.09795	$0.00182	$0.09847	40.0%	0.5%
33							
34	Demand Charge, per kW-Mth- All	$10.00	$10.00	$14.00	$14.00	40.0%	40.0%

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Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026

Summary Of Present And Proposed Rates
Fully Projected Future Test Year 2026

Line		Present Rates (excl GSSR)	Present Rates (incl GSSR present)	Proposed Rates (excl GSSR)	Proposed Rates (incl GSSR present)	Proposed Increase (excl GSSR)	Proposed Increase (incl GSSR present)
35	**Schedules MSL, POL**						
36	Per Lamp per Month	MSL-Present	POL-Present	MSL- Proposed	POL-Proposed	MSL	POL
37		Excludes GSSR	Excludes GSSR	Excludes GSSR	Excludes GSSR		
38	20000 lumens (HG)	$10.76	$8.81	$15.67	$10.19	45.6%	15.7%
39							
40							
41							
42	LED 50W, 5000 lumens OH Cobra	$4.12	$8.33	$6.00	$9.64	45.6%	15.7%
43	LED 50W, 5000 lumens UG Cobra	$11.06	$11.06	$16.10	$12.79	45.6%	15.6%
44	LED 50W, 5000 lumens UG Colonial	$16.03	$16.03	$23.34	$18.54	45.6%	15.7%
45	LED 70W, 15000 lumens OH Cobra	$4.69	$8.89	$6.83	$10.28	45.6%	15.6%
46	LED 70W, 15000 lumens UG Cobra	$11.62	$11.62	$16.92	$13.44	45.6%	15.7%
47	LED 140W, 20000 lumens OH Cobra	$5.81	$10.02	$8.46	$11.59	45.6%	15.7%
48	LED 140W, 20000 lumens UG Cobra	$12.75	$12.75	$18.56	$14.75	45.6%	15.7%
49		**MSL, POL rates are Distribution only**		**MSL, POL rates are Distribution only**			
50	**Schedule EU- Exchange of Service**						
51	Energy Charge, per kWh- All	$0.08732	$0.18397	$0.118660	$0.21531	35.9%	17.0%

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Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026
Bill Comparisons (including GSSR present rate)
Fully Projected Future Test Year 2026

Schedule RS- Residential Service

			Present Rates		Proposed Rates		Proposed Increase	
	Average	Sales (kWh)	Monthly Bill	Cost per kWh	Monthly Bill	Cost per kWh	$ per Month	%
1		Minimum	$12.00		$16.50		$4.50	37.5%
2		1	12.16	$12.15529	16.69	$16.68631	4.53	37.3%
3		10	13.55	$1.35529	18.36	$1.83631	4.81	35.5%
4		100	27.53	$0.27529	35.13	$0.35131	7.60	27.6%
5		250	50.82	$0.20329	63.08	$0.25231	12.26	24.1%
6		500	89.65	$0.17929	109.66	$0.21931	20.01	22.3%
7	All Residential, annual	700	120.70	$0.17243	146.92	$0.20988	26.21	21.7%
8		1,000	167.29	$0.16729	202.81	$0.20281	35.52	21.2%
9		1,500	244.94	$0.16329	295.97	$0.19731	51.03	20.8%
10		2,000	322.58	$0.16129	389.12	$0.19456	66.54	20.6%
11		3,000	477.87	$0.15929	575.43	$0.19181	97.56	20.4%
12								

Schedule RSAE- Residential Service All Electric

			Present Rates		Proposed Rates		Proposed Increase	
	Average	Sales (kWh)	Monthly Bill	Cost per kWh	Monthly Bill	Cost per kWh	$ per Month	%
13		Minimum	$12.00		$16.50		$4.50	37.5%
14		1	12.15	$12.14792	16.68	$16.68138	4.53	37.3%
15		10	13.48	1.34792	18.31	1.83138	4.83	35.9%
16		100	26.79	0.26792	34.64	0.34638	7.85	29.3%
17		250	48.98	0.19592	61.85	0.24738	12.87	26.3%
18		500	85.96	0.17192	107.19	0.21438	21.23	24.7%
19		1,000	159.92	0.15992	197.88	0.19788	37.96	23.7%
20	All RSAE, annual	1,100	174.71	0.15883	216.02	0.19638	41.31	23.6%
21		1,500	233.88	0.15592	288.57	0.19238	54.69	23.4%
22		2,000	307.84	0.15392	379.26	0.18963	71.42	23.2%
23		3,000	455.76	0.15192	560.64	0.18688	104.88	23.0%
24								

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Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026
Bill Comparisons (including GSSR present rate)
Fully Projected Future Test Year 2026

Schedule NRS- Non-Residential Service

			Present Rates		Proposed Rates		Proposed Increase	
	Average	Sales (kWh)	Monthly Bill	Cost per kWh	Monthly Bill	Cost per kWh	$ per Month	%
25		Minimum	$12.22		$16.50		$4.28	35.0%
26		1	12.39	$12.39295	16.71	$16.71266	4.32	34.9%
27		50	20.87	0.41735	27.13	0.54266	6.27	30.0%
28		100	29.52	0.29515	37.77	0.37766	8.25	28.0%
29		250	55.46	0.22183	69.67	0.27866	14.21	25.6%
30	All NRS, annual	430	86.59	0.20137	107.94	0.25103	21.36	24.7%
31		1,000	185.17	0.18517	229.16	0.22916	43.99	23.8%
32		1,500	271.65	0.18110	335.49	0.22366	63.85	23.5%
33		2,000	358.12	0.17906	441.82	0.22091	83.70	23.4%
34		3,000	531.07	0.17702	654.48	0.21816	123.41	23.2%
35								

Schedule NRH- Non-Residential Service Space Heating

			Present Rates		Proposed Rates		Proposed Increase	
	Average	Sales (kWh)	Monthly Bill	Cost per kWh	Monthly Bill	Cost per kWh	$ per Month	%
36		Minimum	$12.22		$16.50		$4.28	35.0%
37		500	102.89	0.20578	143.62	0.28723	40.73	39.6%
38	All NRH, annual	670	133.72	0.19958	186.83	0.27886	53.12	39.7%
39		2,000	374.90	0.18745	524.96	0.26248	150.06	40.0%
40								

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Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026
Bill Comparisons (including GSSR present rate)
Fully Projected Future Test Year 2026

Schedule CS- Commercial Service (Minimum 7 kW)

			Present Rates		Proposed Rates		Proposed Increase	
		Sales (kWh)	Monthly Bill	Cost per kWh	Monthly Bill	Cost per kWh	$ per Month	%
41	**7 kW**	Minimum	78.23		96.71		18.48	23.6%
42	Load factor 10%	511	139.21	0.27242	163.25	0.31948	24.04	17.3%
43	Load factor 20%	1,022	200.19	0.19588	229.79	0.22485	29.61	14.8%
44	Load factor 35%	1,789	291.65	0.16307	329.61	0.18429	37.96	13.0%
45	Load factor 50%	2,555	383.12	0.14995	429.42	0.16807	46.30	12.1%
46	Load factor 60%	3,066	444.10	0.14485	495.96	0.16176	51.87	11.7%
47	Load factor 75%	3,833	535.56	0.13974	595.78	0.15545	60.22	11.2%
48								
49	**10 kW Demand**	Minimum	98.03		124.43		26.40	26.9%
50	Load factor 10%	730	185.14	0.25362	219.49	0.30067	34.35	18.6%
51	Load factor 20%	1,460	272.25	0.18647	314.55	0.21545	42.30	15.5%
52	Load factor 35%	2,555	402.92	0.15770	457.14	0.17892	54.22	13.5%
53	Load factor 50%	3,650	533.58	0.14619	599.73	0.16431	66.15	12.4%
54	Load factor 60%	4,380	620.70	0.14171	694.79	0.15863	74.10	11.9%
55	Load factor 75%	5,475	751.36	0.13724	837.38	0.15295	86.02	11.5%
56								
57	**25 kW Demand**	Minimum	197.03		263.03		66.00	33.5%
58	Load factor 10%	1,825	414.81	0.22729	500.68	0.27435	85.87	20.7%
59	Load factor 20%	3,650	632.58	0.17331	738.33	0.20228	105.75	16.7%
60	Load factor 35%	6,388	959.25	0.15018	1,094.81	0.17140	135.56	14.1%
61	Load factor 50%	9,125	1,285.92	0.14092	1,451.29	0.15905	165.37	12.9%
62	Load factor 60%	10,950	1,503.69	0.13732	1,688.94	0.15424	185.25	12.3%
63	Load factor 75%	13,688	1,830.36	0.13372	2,045.42	0.14944	215.06	11.8%
64								
65	**40 kW Demand**	Minimum	296.03		401.63		$105.60	35.7%
66	Load factor 10%	2,920	644.47	0.22071	781.87	0.26776	137.40	21.3%
67	Load factor 20%	5,840	992.92	0.17002	1,162.11	0.19899	169.20	17.0%
68	Load factor 35%	10,220	1,515.58	0.14830	1,732.48	0.16952	216.90	14.3%
69	Load factor 50%	14,600	2,038.25	0.13961	2,302.84	0.15773	264.59	13.0%
70	Load factor 60%	17,520	2,386.69	0.13623	2,683.08	0.15314	296.39	12.4%
71	Load factor 75%	21,900	2,909.36	0.13285	3,253.45	0.14856	344.09	11.8%

Schedule CSH- Commercial Service Space Heaters (Minimum 7 kW)

		Present Rates		Proposed Rates		Proposed Increase	
	Sales (kWh)	Monthly Bill	Cost per kWh	Monthly Bill	Cost per kWh	$ per Month	%
72	Minimum	$45.81		$45.81		$0.00	-
73	1,000	208.74	$0.20874	315.59	$0.31559	106.85	51.2%
74	24,000	3,956.13	0.16484	6,520.53	0.27169	2,564.40	64.8%

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Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026
Bill Comparisons (including GSSR present rate)
Fully Projected Future Test Year 2026

Schedule IS- General Service (Minimum 2300 volts, 50 kW)

			Sales (kWh)	Present Rates		Proposed Rates		Proposed Increase	
				Monthly Bill	Cost per kWh	Monthly Bill	Cost per kWh	$ per Month	%
75	**Monthly Minimum**			$1,585.00		$2,250.00		665.00	42.0%
76		**150 kW Demand**							
77	**Load Factors**		Minimum	$1,585.00		$2,250.00		665.00	42.0%
78		30%	32,850	5,182.52	0.15776	6,011.04	0.18298	828.53	16.0%
79		40%	43,800	6,255.07	0.14281	7,089.29	0.16186	834.22	13.3%
80		50%	54,750	7,327.62	0.13384	8,167.54	0.14918	839.92	11.5%
81		60%	65,700	8,400.18	0.12786	9,245.78	0.14073	845.61	10.1%
82		75%	82,125	10,009.00	0.12188	10,863.15	0.13228	854.15	8.5%
83									
84		**400 kW Demand**							
85	**Load Factors**		Minimum	$4,085.00		$5,750.00		1,665.00	40.8%
86		30%	87,600	13,678.38	0.15615	15,779.45	0.18013	2,101.07	15.4%
87		40%	116,800	16,538.52	0.14160	18,654.78	0.15972	2,116.26	12.8%
88		50%	146,000	19,398.66	0.13287	21,530.10	0.14747	2,131.44	11.0%
89		60%	175,200	22,258.80	0.12705	24,405.42	0.13930	2,146.62	9.6%
90		75%	219,000	26,549.01	0.12123	28,718.41	0.13113	2,169.40	8.2%
91									
92		**750 kW Demand**							
93	**Load Factors**		Minimum	$7,585.00		$10,650.00		3,065.00	40.4%
94		30%	164,250	25,572.59	0.15569	29,455.22	0.17933	3,882.64	15.2%
95		40%	219,000	30,935.35	0.14126	34,846.46	0.15912	3,911.11	12.6%
96		50%	273,750	36,298.11	0.13260	40,237.69	0.14699	3,939.58	10.9%
97		60%	328,500	41,660.88	0.12682	45,628.92	0.13890	3,968.05	9.5%
98		75%	410,625	49,705.02	0.12105	53,715.77	0.13081	4,010.75	8.1%
99									
100		**1500 kW Demand**							
101	**Load Factors**		Minimum	$15,085.00		$21,150.00		6,065.00	40.2%
102		30%	328,500	51,060.18	0.15543	58,760.45	0.17888	7,700.27	15.1%
103		40%	438,000	61,785.70	0.14106	69,542.91	0.15877	7,757.21	12.6%
104		50%	547,500	72,511.23	0.13244	80,325.38	0.14671	7,814.15	10.8%
105		60%	657,000	83,236.75	0.12669	91,107.84	0.13867	7,871.09	9.5%
106		75%	821,250	99,325.04	0.12094	107,281.54	0.13063	7,956.50	8.0%

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Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026
Bill Comparisons (excluding GSSR)
Fully Projected Future Test Year 2026
Schedule RS- Residential Service

			Present Rates		Proposed Rates		Proposed Increase	
	Average	Sales (kWh)	Monthly Bill	Cost per kWh	Monthly Bill	Cost per kWh	$ per Month	%
1		Minimum	$12.00		$16.50		$4.50	37.5%
2		1	12.06	$12.05864	16.59	$16.58966	4.53	37.6%
3		10	12.59	$1.25864	17.40	$1.73966	4.81	38.2%
4		100	17.86	$0.17864	25.47	$0.25466	7.60	42.6%
5		250	26.66	$0.10664	38.92	$0.15566	12.26	46.0%
6		500	41.32	$0.08264	61.33	$0.12266	20.01	48.4%
7	All Residential, annual	700	53.05	$0.07578	79.26	$0.11323	26.21	49.4%
8		1,000	70.64	$0.07064	106.16	$0.10616	35.52	50.3%
9		1,500	99.96	$0.06664	150.99	$0.10066	51.03	51.1%
10		2,000	129.28	$0.06464	195.82	$0.09791	66.54	51.5%
11		3,000	187.92	$0.06264	285.48	$0.09516	97.56	51.9%
12								

Schedule RSAE- Residential Service All Electric

			Present Rates		Proposed Rates		Proposed Increase	
	Average	Sales (kWh)	Monthly Bill	Cost per kWh	Monthly Bill	Cost per kWh	$ per Month	%
13		Minimum	$12.00		$16.50		$4.50	37.5%
14		1	12.05	$12.05127	16.58	$16.58473	4.53	37.6%
15		10	12.51	1.25127	17.35	1.73473	4.83	38.6%
16		100	17.13	0.17127	24.97	0.24973	7.85	45.8%
17		250	24.82	0.09927	37.68	0.15073	12.87	51.8%
18		500	37.64	0.07527	58.87	0.11773	21.23	56.4%
19		1,000	63.27	0.06327	101.23	0.10123	37.96	60.0%
20	All RSAE, annual	1,100	68.40	0.06218	109.70	0.09973	41.31	60.4%
21		1,500	88.91	0.05927	143.60	0.09573	54.69	61.5%
22		2,000	114.54	0.05727	185.96	0.09298	71.42	62.4%
23		3,000	165.81	0.05527	270.69	0.09023	104.88	63.3%
24								

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Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026
Bill Comparisons (excluding GSSR)
Fully Projected Future Test Year 2026
Schedule NRS- Non-Residential Service

			Present Rates		Proposed Rates		Proposed Increase	
	Average	Sales (kWh)	Monthly Bill	Cost per kWh	Monthly Bill	Cost per kWh	$ per Month	%
25		Minimum	$12.22		$16.50		$4.28	35.0%
26		1	12.30	$12.29630	16.62	$16.61601	4.32	35.1%
27		50	16.04	0.32070	22.30	0.44601	6.27	39.1%
28		100	19.85	0.19850	28.10	0.28101	8.25	41.6%
29		250	31.30	0.12518	45.50	0.18201	14.21	45.4%
30	All NRS, annual	430	45.03	0.10472	66.38	0.15438	21.36	47.4%
31		1,000	88.52	0.08852	132.51	0.13251	43.99	49.7%
32		1,500	126.67	0.08445	190.52	0.12701	63.85	50.4%
33		2,000	164.82	0.08241	248.52	0.12426	83.70	50.8%
34		3,000	241.12	0.08037	364.53	0.12151	123.41	51.2%
35								

Schedule NRH- Non-Residential Service Space Heating

			Present Rates		Proposed Rates		Proposed Increase	
	Average	Sales (kWh)	Monthly Bill	Cost per kWh	Monthly Bill	Cost per kWh	$ per Month	%
36		Minimum	$12.22		$16.50		$4.28	35.0%
37		500	54.57	0.10913	95.29	0.19058	40.73	74.6%
38	All NRH, annual	670	68.96	0.10293	122.08	0.18221	53.12	77.0%
39		2,000	181.60	0.09080	331.66	0.16583	150.06	82.6%
40								

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Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026
Bill Comparisons (excluding GSSR)
Fully Projected Future Test Year 2026
Schedule CS- Commercial Service (Minimum 7 kW)

			Present Rates		Proposed Rates		Proposed Increase	
		Sales (kWh)	Monthly Bill	Cost per kWh	Monthly Bill	Cost per kWh	$ per Month	%
41	**7 kW**	Minimum	78.23		96.71		18.48	23.6%
42	Load factor 10%	511	89.82	0.17577	113.86	0.22283	24.04	26.8%
43	Load factor 20%	1,022	101.41	0.09923	131.02	0.12820	29.61	29.2%
44	Load factor 35%	1,789	118.79	0.06642	156.75	0.08764	37.96	32.0%
45	Load factor 50%	2,555	136.18	0.05330	182.48	0.07142	46.30	34.0%
46	Load factor 60%	3,066	147.77	0.04820	199.64	0.06511	51.87	35.1%
47	Load factor 75%	3,833	165.15	0.04309	225.37	0.05880	60.22	36.5%
48								
49	**10 kW Demand**	Minimum	98.03		124.43		26.40	26.9%
50	Load factor 10%	730	114.59	0.15697	148.94	0.20402	34.35	30.0%
51	Load factor 20%	1,460	131.14	0.08982	173.44	0.11880	42.30	32.3%
52	Load factor 35%	2,555	155.98	0.06105	210.20	0.08227	54.22	34.8%
53	Load factor 50%	3,650	180.81	0.04954	246.96	0.06766	66.15	36.6%
54	Load factor 60%	4,380	197.37	0.04506	271.47	0.06198	74.10	37.5%
55	Load factor 75%	5,475	222.20	0.04059	308.23	0.05630	86.02	38.7%
56								
57	**25 kW Demand**	Minimum	197.03		263.03		66.00	33.5%
58	Load factor 10%	1,825	238.42	0.13064	324.30	0.17770	85.87	36.0%
59	Load factor 20%	3,650	279.81	0.07666	385.56	0.10563	105.75	37.8%
60	Load factor 35%	6,388	341.90	0.05353	477.46	0.07475	135.56	39.7%
61	Load factor 50%	9,125	403.99	0.04427	569.36	0.06240	165.37	40.9%
62	Load factor 60%	10,950	445.38	0.04067	630.62	0.05759	185.25	41.6%
63	Load factor 75%	13,688	507.46	0.03707	722.52	0.05279	215.06	42.4%
64								
65	**40 kW Demand**	Minimum	296.03		401.63		$105.60	35.7%
66	Load factor 10%	2,920	362.26	0.12406	499.65	0.17111	137.40	37.9%
67	Load factor 20%	5,840	428.48	0.07337	597.68	0.10234	169.20	39.5%
68	Load factor 35%	10,220	527.82	0.05165	744.72	0.07287	216.90	41.1%
69	Load factor 50%	14,600	627.16	0.04296	891.75	0.06108	264.59	42.2%
70	Load factor 60%	17,520	693.38	0.03958	989.78	0.05649	296.39	42.8%
71	Load factor 75%	21,900	792.72	0.03620	1,136.81	0.05191	344.09	43.4%

Schedule CSH- Commercial Service Space Heaters (Minimum 7 kW)

		Present Rates		Proposed Rates		Proposed Increase	
	Sales (kWh)	Monthly Bill	Cost per kWh	Monthly Bill	Cost per kWh	$ per Month	%
72	Minimum	$45.81		$45.81		$0.00	-
73	1,000	112.09	$0.11209	218.94	$0.21894	106.85	95.3%
74	24,000	1,636.53	0.06819	4,200.93	0.17504	2,564.40	156.7%

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Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026
Bill Comparisons (excluding GSSR)
Fully Projected Future Test Year 2026

Schedule IS- General Service (Minimum 2300 volts, 50 kW)

			Present Rates		Proposed Rates		Proposed Increase	
		Sales (kWh)	Monthly Bill	Cost per kWh	Monthly Bill	Cost per kWh	$ per Month	%
75	**Monthly Minimum**		$1,585.00		$2,250.00		665.00	42.0%
76		**150 kW Demand**						
77	**Load Factors**	Minimum	$1,585.00		$2,250.00		665.00	42.0%
78	30%	32,850	2,007.57	0.06111	2,836.09	0.08633	828.53	41.3%
79	40%	43,800	2,021.80	0.04616	2,856.02	0.06521	834.22	41.3%
80	50%	54,750	2,036.04	0.03719	2,875.95	0.05253	839.92	41.3%
81	60%	65,700	2,050.27	0.03121	2,895.88	0.04408	845.61	41.2%
82	75%	82,125	2,071.62	0.02523	2,925.77	0.03563	854.15	41.2%
83								
84		**400 kW Demand**						
85	**Load Factors**	Minimum	$4,085.00		$5,750.00		1,665.00	40.8%
86	30%	87,600	5,211.84	0.05950	7,312.91	0.08348	2,101.07	40.3%
87	40%	116,800	5,249.80	0.04495	7,366.06	0.06307	2,116.26	40.3%
88	50%	146,000	5,287.76	0.03622	7,419.20	0.05082	2,131.44	40.3%
89	60%	175,200	5,325.72	0.03040	7,472.34	0.04265	2,146.62	40.3%
90	75%	219,000	5,382.66	0.02458	7,552.06	0.03448	2,169.40	40.3%
91								
92		**750 kW Demand**						
93	**Load Factors**	Minimum	$7,585.00		$10,650.00		3,065.00	40.4%
94	30%	164,250	9,697.83	0.05904	13,580.46	0.08268	3,882.64	40.0%
95	40%	219,000	9,769.00	0.04461	13,680.11	0.06247	3,911.11	40.0%
96	50%	273,750	9,840.18	0.03595	13,779.75	0.05034	3,939.58	40.0%
97	60%	328,500	9,911.35	0.03017	13,879.40	0.04225	3,968.05	40.0%
98	75%	410,625	10,018.11	0.02440	14,028.86	0.03416	4,010.75	40.0%
99								
100		**1500 kW Demand**						
101	**Load Factors**	Minimum	$15,085.00		$21,150.00		6,065.00	40.2%
102	30%	328,500	19,310.65	0.05878	27,010.92	0.08223	7,700.27	39.9%
103	40%	438,000	19,453.00	0.04441	27,210.21	0.06212	7,757.21	39.9%
104	50%	547,500	19,595.35	0.03579	27,409.50	0.05006	7,814.15	39.9%
105	60%	657,000	19,737.70	0.03004	27,608.79	0.04202	7,871.09	39.9%
106	75%	821,250	19,951.23	0.02429	27,907.73	0.03398	7,956.50	39.9%

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Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026
Bill Comparisons (including GSSR effective June 1, 2025)
Fully Projected Future Test Year 2026

Schedule RS- Residential Service

			Present Rates		Proposed Rates		Proposed Increase	
	Average	Sales (kWh)	Monthly Bill	Cost per kWh	Monthly Bill	Cost per kWh	$ per Month	%
1		Minimum	$12.00		$16.50		$4.50	37.5%
2		1	12.19	$12.18679	16.72	$16.71781	4.53	37.2%
3		10	13.87	$1.38679	18.68	$1.86781	4.81	34.7%
4		100	30.68	$0.30679	38.28	$0.38281	7.60	24.8%
5		250	58.70	$0.23479	70.95	$0.28381	12.26	20.9%
6		500	105.40	$0.21079	125.41	$0.25081	20.01	19.0%
7	All Residential, annual	700	142.75	$0.20393	168.97	$0.24138	26.21	18.4%
8		1,000	198.79	$0.19879	234.31	$0.23431	35.52	17.9%
9		1,500	292.19	$0.19479	343.22	$0.22881	51.03	17.5%
10		2,000	385.58	$0.19279	452.12	$0.22606	66.54	17.3%
11		3,000	572.37	$0.19079	669.93	$0.22331	97.56	17.0%
12								

Schedule RSAE- Residential Service All Electric

			Present Rates		Proposed Rates		Proposed Increase	
	Average	Sales (kWh)	Monthly Bill	Cost per kWh	Monthly Bill	Cost per kWh	$ per Month	%
13		Minimum	$12.00		$16.50		$4.50	37.5%
14		1	12.18	$12.17942	16.71	$16.71288	4.53	37.2%
15		10	13.79	1.37942	18.63	1.86288	4.83	35.1%
16		100	29.94	0.29942	37.79	0.37788	7.85	26.2%
17		250	56.86	0.22742	69.72	0.27888	12.87	22.6%
18		500	101.71	0.20342	122.94	0.24588	21.23	20.9%
19		1,000	191.42	0.19142	229.38	0.22938	37.96	19.8%
20	All RSAE, annual	1,100	209.36	0.19033	250.67	0.22788	41.31	19.7%
21		1,500	281.13	0.18742	335.82	0.22388	54.69	19.5%
22		2,000	370.84	0.18542	442.26	0.22113	71.42	19.3%
23		3,000	550.26	0.18342	655.14	0.21838	104.88	19.1%
24								

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Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026
Bill Comparisons (including GSSR effective June 1, 2025)
Fully Projected Future Test Year 2026

Schedule NRS- Non-Residential Service

			Present Rates		Proposed Rates		Proposed Increase	
	Average	Sales (kWh)	Monthly Bill	Cost per kWh	Monthly Bill	Cost per kWh	$ per Month	%
25		Minimum	$12.22		$16.50		$4.28	35.0%
26		1	12.42	$12.42445	16.74	$16.74416	4.32	34.8%
27		50	22.44	0.44885	28.71	0.57416	6.27	27.9%
28		100	32.67	0.32665	40.92	0.40916	8.25	25.3%
29		250	63.33	0.25333	77.54	0.31016	14.21	22.4%
30	All NRS, annual	430	100.13	0.23287	121.49	0.28253	21.36	21.3%
31		1,000	216.67	0.21667	260.66	0.26066	43.99	20.3%
32		1,500	318.90	0.21260	382.74	0.25516	63.85	20.0%
33		2,000	421.12	0.21056	504.82	0.25241	83.70	19.9%
34		3,000	625.57	0.20852	748.98	0.24966	123.41	19.7%
35								

Schedule NRH- Non-Residential Service Space Heating

			Present Rates		Proposed Rates		Proposed Increase	
	Average	Sales (kWh)	Monthly Bill	Cost per kWh	Monthly Bill	Cost per kWh	$ per Month	%
36		Minimum	$12.22		$16.50		$4.28	35.0%
37		500	118.64	0.23728	159.37	0.31873	40.73	34.3%
38	All NRH, annual	670	154.82	0.23108	207.94	0.31036	53.12	34.3%
39		2,000	437.90	0.21895	587.96	0.29398	150.06	34.3%
40								

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Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026
Bill Comparisons (including GSSR effective June 1, 2025)
Fully Projected Future Test Year 2026

Schedule CS- Commercial Service (Minimum 7 kW)

			Present Rates		Proposed Rates		Proposed Increase	
		Sales (kWh)	Monthly Bill	Cost per kWh	Monthly Bill	Cost per kWh	$ per Month	%
41	**7 kW**	Minimum	78.23		96.71		18.48	23.6%
42	Load factor 10%	511	155.30	0.30392	179.35	0.35098	24.04	15.5%
43	Load factor 20%	1,022	232.38	0.22738	261.99	0.25635	29.61	12.7%
44	Load factor 35%	1,789	347.99	0.19457	385.95	0.21579	37.96	10.9%
45	Load factor 50%	2,555	463.60	0.18145	509.90	0.19957	46.30	10.0%
46	Load factor 60%	3,066	540.67	0.17635	592.54	0.19326	51.87	9.6%
47	Load factor 75%	3,833	656.29	0.17124	716.50	0.18695	60.22	9.2%
48								
49	**10 kW Demand**	Minimum	98.03		124.43		26.40	26.9%
50	Load factor 10%	730	208.14	0.28512	242.49	0.33217	34.35	16.5%
51	Load factor 20%	1,460	318.24	0.21797	360.54	0.24695	42.30	13.3%
52	Load factor 35%	2,555	483.40	0.18920	537.62	0.21042	54.22	11.2%
53	Load factor 50%	3,650	648.56	0.17769	714.71	0.19581	66.15	10.2%
54	Load factor 60%	4,380	758.67	0.17321	832.76	0.19013	74.10	9.8%
55	Load factor 75%	5,475	923.82	0.16874	1,009.85	0.18445	86.02	9.3%
56								
57	**25 kW Demand**	Minimum	197.03		263.03		66.00	33.5%
58	Load factor 10%	1,825	472.29	0.25879	558.17	0.30585	85.87	18.2%
59	Load factor 20%	3,650	747.56	0.20481	853.31	0.23378	105.75	14.2%
60	Load factor 35%	6,388	1,160.46	0.18168	1,296.02	0.20290	135.56	11.7%
61	Load factor 50%	9,125	1,573.35	0.17242	1,738.73	0.19055	165.37	10.5%
62	Load factor 60%	10,950	1,848.62	0.16882	2,033.86	0.18574	185.25	10.0%
63	Load factor 75%	13,688	2,261.52	0.16522	2,476.57	0.18094	215.06	9.5%
64								
65	**40 kW Demand**	Minimum	296.03		401.63		$105.60	35.7%
66	Load factor 10%	2,920	736.45	0.25221	873.85	0.29926	137.40	18.7%
67	Load factor 20%	5,840	1,176.88	0.20152	1,346.07	0.23049	169.20	14.4%
68	Load factor 35%	10,220	1,837.51	0.17980	2,054.41	0.20102	216.90	11.8%
69	Load factor 50%	14,600	2,498.15	0.17111	2,762.74	0.18923	264.59	10.6%
70	Load factor 60%	17,520	2,938.57	0.16773	3,234.96	0.18464	296.39	10.1%
71	Load factor 75%	21,900	3,599.21	0.16435	3,943.30	0.18006	344.09	9.6%

Schedule CSH- Commercial Service Space Heaters (Minimum 7 kW)

		Present Rates		Proposed Rates		Proposed Increase	
	Sales (kWh)	Monthly Bill	Cost per kWh	Monthly Bill	Cost per kWh	$ per Month	%
72	Minimum	$45.81		$45.81		$0.00	-
73	1,000	240.24	$0.24024	347.09	$0.34709	106.85	44.5%
74	24,000	4,712.13	0.19634	7,276.53	0.30319	2,564.40	54.4%

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Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026
Bill Comparisons (including GSSR effective June 1, 2025)
Fully Projected Future Test Year 2026

Schedule IS- General Service (Minimum 2300 volts, 50 kW)

			Present Rates		Proposed Rates		Proposed Increase	
		Sales (kWh)	Monthly Bill	Cost per kWh	Monthly Bill	Cost per kWh	$ per Month	%
75	**Monthly Minimum**		$1,585.00		$2,250.00		665.00	42.0%
76		**150 kW Demand**						
77	**Load Factors**	Minimum	$1,585.00		$2,250.00		665.00	42.0%
78	30%	32,850	6,217.29	0.18926	7,045.82	0.21448	828.53	13.3%
79	40%	43,800	7,634.77	0.17431	8,468.99	0.19336	834.22	10.9%
80	50%	54,750	9,052.25	0.16534	9,892.16	0.18068	839.91	9.3%
81	60%	65,700	10,469.73	0.15936	11,315.33	0.17223	845.61	8.1%
82	75%	82,125	12,595.94	0.15338	13,450.09	0.16378	854.15	6.8%
83								
84		**400 kW Demand**						
85	**Load Factors**	Minimum	$4,085.00		$5,750.00		1,665.00	40.8%
86	30%	87,600	16,437.78	0.18765	18,538.85	0.21163	2,101.07	12.8%
87	40%	116,800	20,217.72	0.17310	22,333.98	0.19122	2,116.26	10.5%
88	50%	146,000	23,997.66	0.16437	26,129.10	0.17897	2,131.44	8.9%
89	60%	175,200	27,777.60	0.15855	29,924.22	0.17080	2,146.62	7.7%
90	75%	219,000	33,447.51	0.15273	35,616.91	0.16263	2,169.40	6.5%
91								
92		**750 kW Demand**						
93	**Load Factors**	Minimum	$7,585.00		$10,650.00		3,065.00	40.4%
94	30%	164,250	30,746.46	0.18719	34,629.10	0.21083	3,882.64	12.6%
95	40%	219,000	37,833.85	0.17276	41,744.96	0.19062	3,911.11	10.3%
96	50%	273,750	44,921.24	0.16410	48,860.81	0.17849	3,939.58	8.8%
97	60%	328,500	52,008.63	0.15832	55,976.67	0.17040	3,968.05	7.6%
98	75%	410,625	62,639.71	0.15255	66,650.46	0.16231	4,010.75	6.4%
99								
100		**1500 kW Demand**						
101	**Load Factors**	Minimum	$15,085.00		$21,150.00		6,065.00	40.2%
102	30%	328,500	61,407.93	0.18693	69,108.20	0.21038	7,700.27	12.5%
103	40%	438,000	75,582.70	0.17256	83,339.91	0.19027	7,757.21	10.3%
104	50%	547,500	89,757.48	0.16394	97,571.63	0.17821	7,814.15	8.7%
105	60%	657,000	103,932.25	0.15819	111,803.34	0.17017	7,871.09	7.6%
106	75%	821,250	125,194.41	0.15244	133,150.91	0.16213	7,956.50	6.4%

Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026

Net Operating Income And Rates of Return
HY 2024, FTY 2025 and FPFTY 2026
Answer to 52 Pa. Code 53.52 c[1]

Line	Description	HY 2024		Present Rates 12/31/2025	(A) Present Rates Fully Projected 12/31/2026	Proposed Rates Fully Projected 12/31/2026	(B) Proposed Rates Fully Projected 12/31/2020	(A)-(B) Change from Prior Order
		Per Books	Distribution Only	Distribution Only	Distribution Only	Distribution Only	Settlement Prior	
1	**REVENUE**							
2	Residential	$6,829,521	$3,190,200	$3,388,802	$3,395,335	$5,078,907	$3,261,637	$133,698
3	Commercial and industrial	5,657,570	2,642,167	2,887,490	2,902,837	4,096,297	2,708,336	194,502
4	Lighting	100,851	95,243	94,867	94,867	113,787	90,112	4,755
5	Sales for resale	17,863	8,957	8,957	8,957	12,171	9,732	(776)
6	Rounding						200	(200)
7	Electric operating revenue	12,605,805	5,936,568	6,380,115	6,401,996	9,301,384	6,070,017	331,979
8	Other revenue, net	318,497	318,497	320,653	327,640	327,640	116,459	211,181
9	Under (over) Collections	234,090	0	0	0	0	0	0
10	Total Revenue	13,158,392	6,255,065	6,700,768	6,729,636	9,629,025	6,186,476	543,161
11	*Annual kWH*	*97,019,287*	*97,019,287*	*104,333,284*	*105,861,774*	*105,861,774*	*107,825,923*	*(10,806,636)*
12	**EXPENSES**				Increase	2,899,388		
13	Purchased electricity	5,720,438						
14	Distribution	1,334,849	1,334,849	1,561,937	1,602,629	1,602,629	1,285,908	316,721
15	Customer accounting & collection expen	929,410	929,410	1,050,953	1,084,054	1,084,054	649,803	434,251
16	Sales expense, Public relations	3,171	3,171	19,727	9,737	9,737	8,915	822
17	Administrative & general expenses	1,264,200	1,264,200	1,486,637	1,636,599	1,636,599	929,641	706,958
18	Total Operating expenses	9,252,068	3,531,630	4,119,254	4,333,019	4,333,019	2,874,267	1,458,752
19								
20	Depreciation expense	1,335,247	1,335,247	1,844,192	1,939,404	1,939,404	1,331,977	607,427
21	Taxes other than income	814,557	394,406	420,575	421,866	592,930	377,878	43,988
22	Rate case expense amortization						108,667	(108,667)
23	Total Expenses	11,401,872	5,261,283	6,384,021	6,694,288	6,865,352	4,692,789	2,001,500
24								
25	Net operating income before income t	1,756,519	993,782	316,747	35,348	2,763,673	1,493,687	(1,458,339)
26								
27	Income tax expense	175,781	(44,590)	(60,909)	(139,723)	648,547	447,548	(587,272)
28	NET UTILITY OPERATING INCOME (LOSS) (A)	$1,580,738	$1,038,371	$377,656	$175,071	$2,115,126	$1,046,139	($871,067)
29						0.0818000		
30	RATE BASE (B)		$26,163,779	$26,224,348	$25,857,280	$25,857,280	$14,653,172	$11,510,607
31	RATE OF RETURN ON RATE BASE (A / B)		3.97%	1.44%	0.68%	8.18%	7.14%	

Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026

Net Operating Income And Rates of Return
HY 2024, FTY 2025 and FPFTY 2026
Answer to 52 Pa. Code 53.52 c[1] - Support Sheet No. 1
Support Sheet No. 1- Operating Expense and Going-Level Adjustments

Line	Acct.	Account Description	Year 2023	HY 2024	Changes	FTY 2025	Changes to FPFTY 2026	FPFTY 2026	Labor Year 2023	Labor HY 2024	Labor FTY 2025	Labor FPFTY 2026
1		Power Supply Expenses:										
2	555	Power Purchased	$0	$0	$0	$0	$0	$0				
3		*Total Power Supply expense*	0	0	0	0	0	0	0	0	0	0
4												
5		Distribution Expenses										
6	580	Operations Supv & Eng	0	8,121	(8,121)	0	0	0	0	4,043	0	0
7	582	Station Expense	0	0	0	0	0	0	0	0	0	0
8	583	Overhead Line Expense	686	770	5,024	5,794	225	6,020	(2,379)	(1,766)	3,980	4,098
9	585	Street Lighting Expense	675	146	113	259	9	267	0	127	178	182
10	586	Meter Expense	33,644	36,983	1,462	38,445	1,458	39,903	19,146	21,287	26,220	26,981
11	587	Customer Installation Expense	0	206	52	259	9	267	0	109	178	182
12	588	Miscellaneous Distribution Exp	170,671	173,944	106,478	280,422	5,267	285,688	86,318	91,107	136,556	140,466
13	589	Rents	30,717	32,950	2,350	35,300	0	35,300	0	0	0	0
14		*Total Operating expense*	236,392	253,121	107,357	360,478	6,968	367,446	103,085	114,906	167,111	171,910
15												
16	590	Maint Supv & Eng	85,710	97,875	2,896	100,771	1,013	101,784	37,403	41,204	41,076	42,663
17	591	Maint of Structures	1,848	0	0	0	0	0	792	0	0	0
18	592	Maintenance of Station Equipment	5,697	3,210	1,361	4,571	13,986	18,557	3,834	1,589	1,869	1,924
19	593	Maintenance of Overhead Lines	836,769	869,788	99,284	969,072	16,255	985,327	196,105	223,708	281,824	289,584
20	594	Maintenance of Underground Lines	28,436	30,206	9,850	40,056	257	40,313	3,598	4,482	4,503	4,638
21	595	Maintain Line Transformers	5,677	14,532	(6,659)	7,873	191	8,064	1,742	3,059	3,347	3,447
22	596	Maint. Street Light & Signal Expense	2,991	1,612	(704)	907	35	942	1,700	962	623	641
23	597	Maintenance of Misc. Distrib Plant	75,467	64,505	13,702	78,208	1,987	80,194	63,480	56,551	35,036	36,073
24		*Total Maintenance expense*	1,042,595	1,081,729	119,730	1,201,459	33,723	1,235,182	308,653	331,556	368,279	378,972
25		*Total Operating & Maintenance expens*	1,278,988	1,334,849	227,088	1,561,937	40,692	1,602,629	411,738	446,462	535,390	550,882
26												
27		Customer Accounting & Collection Expenses:										
28	902	Meter Reading Expense	19,808	21,775	(5,853)	15,922	622	16,544	10,767	12,359	10,936	11,261
29	903	Customer Records & Collection Exp	872,949	907,634	107,397	1,015,031	32,479	1,047,510	307,531	309,910	330,520	353,116
30	904	Uncollectible Accounts	0	0	20,000	20,000	0	20,000	0	0	0	0
31		*Total Customer Accting & Coll. expens*	892,757	929,410	121,544	1,050,953	33,101	1,084,054	318,298	322,269	341,456	364,377
32												

Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026

Net Operating Income And Rates of Return
HY 2024, FTY 2025 and FPFTY 2026
Answer to 52 Pa. Code 53.52 c[1] - Support Sheet No. 1
Support Sheet No. 1- Operating Expense and Going-Level Adjustments

Line	Acct.	Account Description	Year 2023	HY 2024	Changes	FTY 2025	Changes to FPFTY 2026	FPFTY 2026	Labor Year 2023	Labor HY 2024	Labor FTY 2025	Labor FPFTY 2026
33		Sales expense, Public relations										
34	908-913	Safety and Communications	4,082	3,171	16,555	19,727	(9,990)	9,737	1,735	180	156	161
35												
36		Administrative & General Expenses:										
37	920	Administrative & General Salaries	652,639	757,901	111,995	869,897	41,333	911,229	301,608	355,049	401,562	426,497
38	921	Office Supplies & Expenses	61,925	112,900	10,107	123,007	(13,297)	109,710	0	0	0	0
39	923	Outside Services Employed	87,889	137,115	17,410	154,525	0	154,525	0	0	0	0
40	924	Property Insurance	51,268	53,098	8,312	61,410	0	61,410	0	0	0	0
41	926	Employee Pensions & Benefits	0	0	0	0	0	0	0	0	0	0
42	928	Regulatory commission expenses	68,366	42,985	15	43,000	110,393	153,393	0	0	0	0
43	930	Miscellaneous General Expense	105,355	84,404	15,347	99,751	10,830	110,581	3,074	0	3,100	3,100
44	931	Rents	2,442	3,611	(1,411)	2,200	0	2,200	0	0	0	0
45	932	Maintenance of General Property	112,580	72,186	60,662	132,847	704	133,551	50,565	11,364	12,378	12,746
46		*Total Administrative & General expens*	1,142,464	1,264,200	222,437	1,486,637	149,962	1,636,599	355,248	366,413	417,040	442,344
47												
48		**Total Operating & Maintenance Expe**	**$3,318,291**	**$3,531,630**	**$587,624**	**$4,119,254**	**$213,764**	**$4,333,019**	**$1,087,018**	**$1,135,323**	**$1,294,042**	**$1,357,763**
49			$3,318,291	$3,531,630	587,624	$4,119,254	213,764	$4,333,019	1,087,018	1,135,323	1,294,042	1,357,763

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Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026

Support Sheet No. 2- Summary of Cost of Capital and Fair Rate of Return Based upon a Hypothetical Ratemaking Capital Structure
12/31/2025 and 12/31/2026

Line	Type of Capital	Ratios (1)	Cost Rate		Weighted Cost Rate
1	Long-Term Debt	51.06%	4.850%		2.47641%
2	Short-Term Debt				0.00%
3	Total Debt	51.06%			2.48%
4					
5	Preferred Stock				0.00000%
6	Common Equity	48.94%	11.65%	9.2300%	5.70151%
7	Total	100.00%	9.31%		8.17792%
8				Target ROR	8.18%
9					
10	[1] Recommended hypothetical capital structure ratios as discussed in direct testimony.				
11					2,899,388

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Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026

Net Operating Income And Rates of Return
HY 2024, FTY 2025 and FPFTY 2026
Answer to 52 Pa. Code 53.52 c[1]
Support Sheet No. 3- Taxes Other Than Income

Line			HY 2024		Present Rates Year Ended 12/31/2025	Present Rates Future Test Year Ended 12/31/2026	Proposed Rates Future Test Year Ended 12/31/2026
			Per Books	Distribution Only	Distribution Only	Distribution Only	Distribution Only
1	Taxes other than income:						
2	Pennsylvania Use Tax		$837	$837	$837	$837	$837
3	PUC Assessment			0	0	0	0
4	Lease Tax		(10,663)				
5	Public Utility Realty Tax (including surcharge		43,311	43,311	43,311	43,311	43,311
6	Pennsylvania Gross Receipts Tax		781,072	350,258	376,427	377,718	548,782
7			$814,557	$394,406	$420,575	$421,866	$592,930
8							
9	**Gross Receipts Tax**						
10	Electric operating revenue		$12,605,805	$5,936,568	$6,380,115	$6,401,996	$9,301,384
11							
12							
13	Gross Receipts Taxable		$12,605,805	$5,936,568	$6,380,115	$6,401,996	$9,301,384
14	Gross Receipts Tax at Present Rate	5.90%	$743,742	$350,258	$376,427	$377,718	$548,782
15	Rounding difference		37,330				
16	Gross Receipts Tax expense		$781,072	$350,258	$376,427	$377,718	$548,782
17							
18	**Normalized Rate case expense**						
19	Estimated expenses					$331,178	
20	Amortization period (years)					3	
21	Normalized Rate case expense					$110,393	$110,393

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Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026

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Net Operating Income And Rates of Return
HY 2024, FTY 2025 and FPFTY 2026
Answer to 52 Pa. Code 53.52 c[1]
Support Sheet No. 4- Income Tax Calculations

Line	Description		HY 2024		Present Rates 12/31/2025	Present Rates Fully Projected 12/31/2026	Proposed Rates Fully Projected 12/31/2026
			Per Books	Distribution Only	Distribution Only	Distribution Only	Distribution Only
1	Net Operating Income Excluding Income Taxes		$1,756,519	$993,782	$316,747	$35,348	$2,763,673
2							
3	Synchronized interest expense:						
4	Rate base		26,163,779	26,163,779	26,224,348	25,857,280	25,857,280
5							
6	Rate base for interest compuation		26,163,779	26,163,779	26,224,348	25,857,280	25,857,280
7	Weighted Cost of debt		2.476%	2.476%	2.476%	2.476%	2.476%
8	Synchronized interest expense		647,922	647,922	649,422	640,332	640,332
9	Taxable income before depreciation tax adjustments		1,108,597	345,859	(332,676)	(604,984)	2,123,340
10							
11	Pennsylvania depreciation adjustment:						
12	Tax depreciation (using DDB method)		(2,466,799)	(2,466,799)	(2,176,619)	(2,195,614)	(2,195,614)
13	Book depreciation		1,335,247	1,335,247	1,844,192	1,939,404	1,939,404
14	Pennsylvania depreciation adjustment		(1,131,552)	(1,131,552)	(332,427)	(256,211)	(256,211)
15	Pennsylvania taxable income		(22,955)	(785,693)	(665,103)	(861,195)	1,867,130
16	Regulatory Pennsylvania income tax expense	9.99%	(2,293)	(78,491)	(66,444)	(86,033)	186,526
17							
18	Federal depreciation adjustment:						
19	Tax depreciation (using SL method)		(1,598,164)	(1,598,164)	(1,551,605)	(1,676,119)	(1,676,119)
20	Book depreciation		1,335,247	1,335,247	1,844,192	1,939,404	1,939,404
21	Federal depreciation adjustment		(262,917)	(262,917)	292,587	263,285	263,285
22							
23	Taxable income before depreciation tax adjustments		1,108,597	345,859	(332,676)	(604,984)	2,123,340
24	Federal depreciation adjustment		(262,917)	(262,917)	292,587	263,285	263,285
25	Pennsylvania income tax expense		2,293	78,491	66,444	86,033	(186,526)
26	Federal taxable income		847,973	161,433	26,356	(255,666)	2,200,099
27	Regulatory Federal income tax expense	21.00%	178,074	33,901	5,535	(53,690)	462,021
28							
29	Regulatory Total income tax expense		$175,781	($44,590)	($60,909)	($139,723)	$648,547
30							
31	Deferred Federal Income Tax expense (included in above):						
32	Tax depreciation (using SL method)		1,598,164	1,598,164	1,551,605	1,676,119	1,676,119
33	Tax depreciation (using DDB method)		2,466,799	2,466,799	2,176,619	2,195,614	2,195,614
34			868,635	868,635	625,014	519,496	519,496
35	Federal tax rate		21.00%	21.00%	21.00%	21.00%	21.00%
36	Deferred Federal income tax (credit)		$182,413	$182,413	$131,253	$109,094	$109,094
37	Combined statutory tax rate	28.89%					

Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026

Net Operating Income And Rates of Return
HY 2024, FTY 2025 and FPFTY 2026
Answer to 52 Pa. Code 53.52 c[1]
Support Sheet No. 5- Computation of Rate Base

Line	Description		HY 2024	FTY 2025	FPFTY 2026
1	**Utility Plant in Service**				
2	Assets	Sch. C3, line 23	$ 41,101,936	$ 42,831,436	$ 44,666,856
3	Less: Accumulated Depreciation	Sch. C3, line 23	(15,226,786)	(17,226,319)	(19,321,064)
4			25,875,150	25,605,116	25,345,792
5					
6	Less: Accumulated deferred income taxes (ADIT)	Line 32	96,455	19,318	(38,728)
7					
8	Less: Customer deposits	Sch. C2, line 52	(195,713)	(195,713)	(195,713)
9	Accrued Pension / OPEB Liability	Line 47	(295,779)	35,399	(19,798)
10	Materials & Supplies	Sch. C2, line 22	247,983	247,983	247,983
11			25,728,096	25,712,103	25,339,536
12	Cash Working Capital Allowance	Line 25	435,683	512,245	517,744
13	RATE BASE		$ 26,163,779	$ 26,224,348	$ 25,857,280
14					
15	**Cash Working Capital Allowance:**				
16	Operating Expenses	Sch. C1, line 23	$ 5,261,283	$ 6,384,021	$ 6,694,288
17					
18	Deductions:				
19	Taxes Oher Than Income	Sch. C1-3, line 7	420,575	421,866	592,930
20	Uncollectible accounts	Sch. C1-1, line 30	20,000	20,000	20,000
21	Depreciation Expense	Sch. C1, line 20	1,335,247	1,844,192	1,939,404
22	Total Deductions		1,775,822	2,286,058	2,552,333
23	Cash Operating Expenses		3,485,461	4,097,963	4,141,955
24	Cash Operating Expenses Ratio		1/8	1/8	1/8
25	Cash Working Capital Allowance (A plus B)		$ 435,683	$ 512,245	$ 517,744
26					
27	Regulatory Accumluated deferred income tax:				
28	Accumulated depreciation based on tax expense borne by ratepayers		26,630,508	28,182,113	29,858,231
29	Accumulated depreciation based on taxes paid by company		26,171,198	28,090,123	30,042,650
30	(Higher) depreciation taken by company		459,310	91,990	(184,419)
31	Federal tax rate		21.00%	21.00%	21.00%
32	Regulatory Accumluated deferred income tax (liability)		96,455	19,318	(38,728)
34	Excess deferred income tax:(EDIT)	NOT USED			
41					
42	Regulatoy (Liability) and Assets				
43	Accrued postretirement cost (Liability)		(185,579)	(185,579)	(185,579)
44	Regulatoy (Liability)		(230,379)	(230,379)	(230,379)
45	Regulatory Assets			331,178	275,981
46	Deferred tax asset related to OPEB		120,179	120,179	120,179
47			(295,779)	35,399	(19,798)

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Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026

Balance Sheets
12/31/2024, 12/31/2025 and 12/31/2026
Answer to 52 Pa. Code 53.52 c[2]

Line	Account Title	Per Books 12/31/2024	Pro Forma 12/31/2025	Pro Forma 12/31/2026
1	**Assets and Other Debits**			
2	Utility Plant			
3	Electric plant in service	$41,101,936	$42,831,436	$44,666,856
4	Construction work in progress	27,017	27,017	27,017
5	Accumulated depreciation	(15,226,786)	(17,226,319)	(19,321,064)
6	*Total utility plant*	25,902,167	25,632,133	25,372,809
7				
8	Other Property and Investments:			
9	Non-utility property	144,043	144,043	144,043
10	Regulatory asset	40,145	40,145	40,145
11	Regulatory asset- RS Plan		0	0
12	Rentals and other	65,176	65,176	65,176
13	*Total other property and investments*	249,364	249,364	249,364
14				
15	Current Assets:			
16	Cash	203,335	203,335	203,335
17	Customer accounts receivable	1,198,530	1,198,530	1,198,530
18	Provison for uncollectible accounts	(12,306)	(12,306)	(12,306)
19	Accrued utility revenues	667,515	667,515	667,515
20	Other accounts receivable	287,005	287,005	287,005
21	Advances to affiliates	49,000	49,000	49,000
22	Inventories	247,983	247,983	247,983
23	Prepayments	8,439	8,439	8,439
24	Prepaid Costs	108,863	108,863	108,863
25	GSSR Under (Over)	72,766	72,766	72,766
26	*Total current assets*	2,831,130	2,831,130	2,831,130
27				
28	**Total Assets and Other Debits**	**$28,982,661**	**$28,712,627**	**$28,453,303**
29				

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Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026

Balance Sheets
12/31/2024, 12/31/2025 and 12/31/2026
Answer to 52 Pa. Code 53.52 c[2]

Line	Account Title	Per Books 12/31/2024	Pro Forma 12/31/2025	Pro Forma 12/31/2026
30	**Liabilities and Other Credits**			
31				
32	Proprietary Capital:			
33	Preferred stock	$125,800	$125,800	$125,800
34	Common stock Issued	240,146	240,146	240,146
35	Retained earnings	5,050,799	5,428,455	5,603,526
36	Treasury stock, at cost	(159,250)	(159,250)	(159,250)
37	*Total proprietary capital*	5,257,495	5,635,151	5,810,222
38				
39	Long-Term Debt:			
40	Long term debt	18,477,675	17,612,601	16,710,309
41	Capitalized Lease Obligations	349,544	220,330	105,672
42	*Total long-term debt*	18,827,219	17,832,931	16,815,981
43				
44	Current and Accrued Liabilities:			
45	Line of Credit	$700,000	$1,023,936	$1,611,500
46	Current maturities of long-term debt	865,074	902,292	941,209
47	Current maturities of capitalized leases	129,214	114,658	70,731
48	Accounts payable- Trade	520,911	520,911	520,911
49	Accounts payable- Related party	133,216	133,216	133,216
50	Due for Purchased electricity	537,362	537,362	537,362
51	Accrued expenses	227,799	227,799	227,799
52	Customer deposits	195,713	195,713	195,713
53	Derivative investment		0	0
54	Overcollected power costs		0	0
55	*Total current and accrued liabilities*	3,309,289	3,655,887	4,238,441
56				
57	Deferred Credits and Other Liabilities:			
58	Deferred income taxes	1,172,700	1,172,700	1,172,700
59	Accrued postretirement cost	185,579	185,579	185,579
60	Regulatory Liability	230,379	230,379	230,379
61	*Total deferred credits*	1,588,658	1,588,658	1,588,658
62				
63	**Total Liabilities and Other Credits**	**$28,982,661**	**$28,712,627**	**$28,453,303**

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Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026

Original Cost of Utility Plant in Service
12/31/2024, 12/31/2025 and 12/31/2026
Answer to 52 Pa. Code 53.52 c[3]

			Original Cost			Original Cost			Original Cost			
			Balance 12/31/2023	HY 2024		Balance 12/31/2024	FTY 2025		Balance 12/31/2025	FPFTY 2026		Balance 12/31/2026
Line	Acct No.	Account Title	Pro Forma	Additions	Retirements	Pro Forma	Additions	Retirements	Pro Forma	Additions	Retirements	Pro Forma
1	*Distribution Plant.*											
2	360	Land & Land Rights	178,334			178,334			178,334			178,334
3	361	Structures and improvements				0			0			0
4	362	Station Equipment	3,654,978	13,265		3,668,243			3,668,243			3,668,243
5	362.01	Station Equipment- Fully depr.	324,557			324,557			324,557			324,557
6	364	Poles, Tower & Fixtures	12,456,164	1,918,214	(917,791)	13,456,587	734,500		14,191,087	742,085		14,933,172
7	365	Overhead Conductors & Devices	5,529,274	1,721,121	(1,166,423)	6,083,972	362,500		6,446,472	358,475		6,804,947
8	366	Underground Conduit	26,899			26,899			26,899			26,899
9	367	Underground Conductors & Devices	1,008,032	19,299	(15,781)	1,011,550			1,011,550			1,011,550
10	368	Line Transformers	2,923,411	285,923	(11,002)	3,198,332	58,500		3,256,832	108,755		3,365,587
11	369	Services	849,838	12,862	(7,390)	855,310	101,000		956,310	104,030		1,060,340
12	369.1	Underground Services	1,300,817	76,122	(32,390)	1,344,549	40,000		1,384,549	41,200		1,425,749
13	370	Meters	986,943	27,460	(2,922)	1,011,481	20,000		1,031,481	10,000		1,041,481
14	371	Installations on Customers' premises	373,328	4,992	(8,702)	369,618	150,000		519,618	0		519,618
15	373	Street Lighting & Signal Systems	118,915	419	(62)	119,272	3,000		122,272	3,000		125,272
16	Total Distribution Plant		29,731,490	4,079,677	(2,162,464)	31,648,703	1,469,500	0	33,118,203	1,367,545	0	34,485,748
17												
18	*General Plant*											
19	390.1	Structures & Improvements, office	2,486,413	3,722,470	(544,972)	5,663,911			5,663,911			5,663,911
20	390.2	Structures & Improvements, other	884,002			884,002			884,002			884,002
21	391	Office Furniture & Equipment	601,624	297,517	(124,652)	774,489			774,489			774,489
22	391.1	Office Furn & Equip- Fully depr.				0			0			0
23	392	Transportation Equipment	1,646,618	66,390	(180,998)	1,532,010	250,000		1,782,010	455,000		2,237,010
24	394	Tools, Shop & Garage Equipment	90,042			90,042	10,000		100,042	12,875		112,917
25	395	Laboratory Equipment	96,079		(80,650)	15,429			15,429			15,429
26	396	Power Operated Equipment	98,149	72,184	(80,519)	89,814			89,814			89,814
27	397	Communication Equipment	110,323	7,578		117,901			117,901			117,901
28	398	Miscellaneous Equipment				0			0			0
29		Intangible plant, organization	1,046			1,046			1,046			1,046
30	301	Intangible plant, EDI	284,588			284,588			284,588			284,588
31		Total General Plant	6,298,884	4,166,139	(1,011,791)	9,453,232	260,000	0	9,713,232	467,875	0	10,181,107
32												
33		Total Plant in Service	36,030,374	8,245,816	(3,174,254)	41,101,936	1,729,500	0	42,831,436	1,835,420	0	44,666,856

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Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026

Original Cost of Utility Plant in Service
12/31/2024, 12/31/2025 and 12/31/2026
Answer to 52 Pa. Code 53.52 c[3]

				Accumulated Depreciation			Accumulated Depreciation		Accumulated Depreciation			Net Book Valu
				Balance	HY 2024		Balance	FTY 2025	Balance	FPFTY 2026	Balance	12/31/2026
Line	Acct No.	Account Title	Depr. Rate	12/31/2023 Balance	Additions	Retirements	12/31/2024 Balance	Additions	12/31/2025 Balance	Additions	12/31/2026 Balance	Balance
1	*Distribution Plant.*											
2	360	Land & Land Rights		0	0	0	0	0	0	0	0	178,334
3	361	Structures and improvements	4.08%				-		-		-	0
4	362	Station Equipment	6.88%	2,921,442	141,847	-	3,063,289	252,375	3,315,664	252,375	3,568,039	100,204
5	362.01	Station Equipment- Fully depr.		324,557			324,557	-	324,557	-	324,557	0
6	364	Poles, Tower & Fixtures	3.50%	3,885,628	440,594	(216,988)	4,109,234	483,834	4,593,068	509,675	5,102,743	9,830,429
7	365	Overhead Conductors & Devices	3.97%	1,707,606	221,459	(117,991)	1,811,074	248,729	2,059,803	263,041	2,322,844	4,482,103
8	366	Underground Conduit	3.15%	10,761	849		11,610	847	12,457	847	13,305	13,594
9	367	Underground Conductors & Devices	4.36%	634,193	43,964		678,157	44,104	722,261	44,104	766,364	245,186
10	368	Line Transformers	3.52%	1,388,859	102,104	(23,844)	1,467,119	113,611	1,580,730	116,555	1,697,284	1,668,303
11	369	Services	6.00%	788,699	9,466	(5,385)	792,780	54,349	847,129	60,499	907,628	152,712
12	369.1	Underground Services	2.48%	464,366	32,826	(1,188)	496,004	33,841	529,845	34,848	564,693	861,057
13	370	Meters	7.70%	556,160	75,858	(2,922)	629,096	78,654	707,750	79,809	787,559	253,922
14	371	Installations on Customers' premises	10.37%	(9,128)	38,453	(13,588)	15,737	46,107	61,844	53,884	115,728	403,889
15	373	Street Lighting & Signal Systems	2.40%	(71,623)	2,861	(149)	(68,911)	2,899	(66,012)	2,971	(63,042)	188,314
16	Total Distribution Plant			12,601,520	1,110,281	(382,055)	13,329,746	1,359,349	14,689,095	1,418,607	16,107,702	18,378,046
17												
18	*General Plant*											
19	390.1	Structures & Improvements, office	4.58%	507,553	92,336	(485,119)	114,770	259,407	374,177	259,407	633,584	5,030,327
20	390.2	Structures & Improvements, other	5.20%	31,957	45,708		77,665	45,968	123,633	45,968	169,601	714,401
21	391	Office Furniture & Equipment	19.49%	378,038	69,221	(122,201)	325,058	150,948	476,006	150,948	626,954	147,535
22	391.1	Office Furn & Equip- Fully depr.					0	0	0	0	0	0
23	392	Transportation Equipment	10.00%	1,035,960	155,341	(180,998)	1,010,303	165,701	1,176,004	200,951	1,376,955	860,055
24	394	Tools, Shop & Garage Equipment	6.17%	29,100	4,976		34,076	5,864	39,940	6,570	46,510	66,407
25	395	Laboratory Equipment	2.66%	90,397	1,544	(80,650)	11,291	410	11,701	410	12,112	3,318
26	396	Power Operated Equipment	3.11%	59,514	2,845	(61,308)	1,051	2,793	3,844	2,793	6,637	83,176
27	397	Communication Equipment	7.71%	29,968	8,336		38,304	9,090	47,394	9,090	56,484	61,417
28	398	Miscellaneous Equipment	0.00%	(64)			(64)	0	(64)	0	(64)	64
29		Intangible plant, organization	0.00%	0			0	0	0	0	0	1,046
30	301	Intangible plant, EDI	14.28%	284,586			284,586	2	284,588	0	284,588	0
31		Total General Plant		2,447,009	380,307	(930,276)	1,897,040	640,184	2,537,224	676,138	3,213,362	6,967,746
32												
33		Total Plant in Service		15,048,529	1,490,588	(1,312,331)	15,226,786	1,999,533	17,226,319	2,094,745	19,321,064	25,345,792

C4

Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026

Reserve for Depreciation of Utility Plant
12/31/2024, 12/31/2025 and 12/31/2026
Answer to 52 Pa. Code 53.52 c[4]

	Account Title	Per Books 12/31/2024	Pro Forma 12/31/2025	Pro Forma 12/31/2026
1	Reserve for Depreciation	$15,226,786	$17,226,319	$19,321,064

C5

Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026

Operating Income Setting Forth the Operating Revenues and Expenses at Present Rates
HY 2024, FTY 2025 and FPFTY 2026
Answer to 52 Pa. Code 53.52 c[5]

	Account Title	Year Ended 12/31/2024 [Per Books]	Year Ended 12/31/2024 Distribution Only	Year Ended 12/31/2025 Distribution Only	Year Ended 12/31/2026 Distribution Only
1	Operating revenue	$13,158,392	$6,255,065	$6,700,768	$6,729,636
2					
3	Operating revenue deductions:				
4	Operating expenses	9,252,068	3,531,630	4,119,254	4,333,019
5	Depreciation expense	1,335,247	1,335,247	1,844,192	1,939,404
6	Taxes other than income tax	814,557	394,406	420,575	421,866
7	Rate case expense amortization	0	0	0	0
8	Total Operating revenue deductions	11,401,872	5,261,283	6,384,021	6,694,288
9					
10	Net operating income before income taxes	1,756,519	993,782	316,747	35,348
11					
12	Income tax expense	175,781	(44,590)	(60,909)	(139,723)
13					
14	Net utility operating income	$1,580,738	$1,038,371	$377,656	$175,071

C5-1

Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026

Comparison to Prior Rate Case
Prior Rate Case and FPFTY 2026

Line	Description	FPFTY 2026	R-2019-3008208, Order	Difference	Gross-Up for GRT	Revenue Requirement
1	Revenue	6,729,636	5,348,459	1,381,177	1.0000	(1,381,177)
2						
3	*kWh*	*105,861,774*	*106,065,175*			
4						
5	O&M	4,333,019	2,513,845	1,819,174	1.0627	1,933,234
6	Taxes other than income, Rate Case	421,866	414,415	7,451	1.0627	7,918
7	Depreciation	1,939,404	1,162,329	777,075	1.0627	825,797
8	Income tax	(139,723)	268,113			
9	Net Income	175,071	989,758			
10						
11	Rate Base	$25,857,280	$13,819,457	12,037,823		
12	Required Return	8.18%	7.16%			
13	Target Return	2,115,126	989,758	1,125,368	1.0627	1,195,928
14						
15	Income Tax Expense	648,547	268,113	380,434	1.0627	404,287
16						
17	Rounding					(86,599)
18	Revenue Increase Required					2,899,388
19						
20						

D

Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026
Summary of Allocator Values

Line	Units	Allocator Names	Total	Sch. 1- RS	Sch. 2- RSAE	Sch. 3- NRS	Sch. 3- NRH	Sch. 4- CS	Sch. 4- CSH	Sch. 5- IS	Sch. 6- MSL	Sch. 7- POL	Sch. 8- EU
		Class Allocators											
1	**InputAlloc**	**ALLOCATION VALUES**											
2	MWh	MWh-Meter	105,861,774	44,812,773	397,781	4,732,166	6,256	29,056,715	7,216	26,746,293	0	0	102,572
3	MW	NCP-Prim	20,036	9,206	123	846	9	5,356	18	4,411	13	41	12
4	MW	NCP-Sec	15,613	9,206	123	846	9	5,356	18	0	13	41	0
5	MW	NCP-Ltr	3,689	0	0	0	4	3,616	14	0	13	41	0
6	#	AVG-CUST	6,538	5,159	29	938	1	392	1	13	0	0	4
7	$	Services_Cost	5,345,508	3,952,747	22,346	718,786	766	627,903	1,602	21,357	0	0	0
8	#	Meters	6,538	5,159	29	938	1	392	1	13	0	0	4
9	$	Meter_Cost	3,086,287	1,857,300	10,500	337,740	360	671,990	1,714	158,987	0	0	47,696
10	$	Dist_Rev	6,401,996	3,370,741	24,594	498,637	676	1,522,475	1,028	880,020	13,496	81,371	8,957
11	$	Total_Rev	13,072,503	6,981,957	53,402	834,441	1,630	3,223,216	1,585	1,857,933	19,106	81,371	17,863
12	$	Supp_Rev	6,670,507	3,611,216	28,807	335,804	954	1,700,741	557	977,913	5,609	0	8,907
13	$	CustDeposits	12120000.0%	6988666.7%	51333.3%	680236.8%	1812.2%	2739398.7%	1355.1%	1569374.2%	0.0%	72060.7%	15762.3%
14	$	Write-Offs	100.0%	87.0%	0.6%	1.7%	0.0%	6.7%	0.0%	3.8%	0.0%	0.2%	0.0%
15	#	StLgt-Lamps	2								1	1	
16													

	InputFunc	FUNCTIONAL ALLOCATORS	Total	Supply	Transmission	Primary Dist	Secondary Dist
17							
18		OH_Cond	100.00%			83.37%	16.63%
19		UG_Cond	100.00%			57.35%	42.65%
20		Trans	100.00%			0.00%	100.00%
21							

	InputClass	CLASSIFICATIONS	Total	Demand	Commodity	Customer
22						
23		PTF-Sec-Z	100.00%	36.96%		63.04%
24		OH-Sec-Z	100.00%	43.97%		56.03%
25		UG-Sec-Z	100.00%	63.71%		36.29%
26		Trans-Min	100.00%	22.45%		77.55%
27						
28						

D1

Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026
Distribution System Functionalizaton and Classification

		Primary / Secondary Split for OH ad UG Conductors		
Line	Conductor type	Circuit Miles	Line Miles (Circuit	Description
1	OH Primary (1 Ph)	304.82	609.64	1 phase wire, 1 neutral wire
2	OH Primary (2 Ph)	6.99	20.97	2 phase wires, 1 neutral wire
3	OH Primary (3 Ph)	72.84	291.36	3 phase wires, 1 neutral wire
4	OH Secondary	111.47	111.47	1 triplexed conductor
5	UG Primary (1 Ph)	32.28	32.28	1 cable with concentric neutral
6	UG Primary (2 Ph)	0.49	0.98	2 cable with concentric neutral
7	UG Primary (3 Ph)	6.86	20.58	3 cable with concentric neutral
8	UG Secondary	34.29	34.29	1 duplexed or triplexed conduct
9		570.04	1121.57	
11	**Totals**			
12	OH Primary	384.65	921.97	
13	OH Secondary	111.47	111.47	
14		496.12	1033.44	
15				
16	UG Primary	39.63	53.84	
17	UG Secondary	34.29	34.29	
18		73.92	88.13	
19				
20	**Totals**			**Average**
21	OH Primary	77.53%	89.21%	83.37%
22	OH Secondary	22.47%	10.79%	16.63%
23		100.00%	100.00%	100.00%
24				
25	UG Primary	53.61%	61.09%	57.35%
26	UG Secondary	46.39%	38.91%	42.65%
27		100.00%	100.00%	100.00%
28				

D1

Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026
Distribution System Functionalizaton and Classification

29	**Zero-Load Components for Secondary**			
30		**Poles**	**Overhead Conductors**	**Underground Conductors**
31	Labor	37.2%	31.7%	8.9%
32	Overhead	14.4%	10.5%	4.5%
33	Vehicle	13.3%	8.8%	2.8%
34	**Zero-Load Component**	**64.9%**	**51.0%**	**16.2%**
35	Material	35.1%	49.0%	83.8%
36	Total Cost	100.0%	100.0%	100.0%
37	Overheads are spread over labor hours.			
38	Zero-Load Component	64.9%	51.0%	16.2%
39	Prior Study	61.2%	61.1%	56.4%
40	**Average**	**63.0%**	**56.0%**	**36.3%**
41				
42		**Poles**	**Overhead Conductors**	**Underground Conductors**
43	Labor	414,674	191,263	313
44	Overhead	160,680	63,525	159
45	Transportation	148,166	53,303	99
46	Materials	392,078	296,158	2,947
47		1,115,598	604,249	3,518
48		Account 364	Account 365	Account 367

D2

Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026
NCP- Sum of Customers' Usage

Line	Description	COMPUTED CLASS DEMANDS (NCPs)										
		Sch. 1- RS	Sch. 2- RSAE	Sch. 3- NRS	Sch. 3- NRH	Sch. 4- CS	Sch. 4- CSH	Sch. 5- IS	Sch. 6- MSL	Sch. 7- POL	Sch. 8- EU	Total
1	Total Number of Customers	5,159	29	938	1	392	1	13			4	6,538
2	Average Peak per Customer	-	-	-	-	-	-	-			-	
3												
4												
5												
6	**NCP- Primary**	9,206	123	846	9	5,356	18	4,411	13	41	12	20,036
7	Class peaks											-
8	**Shares of Total**	45.95%	0.61%	4.22%	0.04%	26.73%	0.09%	22.01%	0.07%	0.21%	0.06%	100.00%
9												
10												
11	1CP	8,446	58	782	-	5,203	-	4,179	-	-	-	18,668
12	Share of 1CP	45.25%	0.31%	4.19%	0.00%	27.87%	0.00%	22.39%	0.00%	0.00%	0.00%	100.00%
13												
14	**NCP- Secondary**	9,206	123	846	9	5,356	18		13	41		15,613
15	Class peaks	-	-	-	-	-	-		-	-		-
16	**Shares of Total**	58.96%	0.79%	5.42%	0.06%	34.31%	0.12%	0.00%	0.09%	0.27%	0.00%	100.00%
17												
18	**NCP-LTr**											
19	Secondary Class peaks	9,206	123	846	9	5,356	18		13	41		15,613
20	Capacity of Minimum system	22,904	129	4,165	4	1,740	4	59	-	-	18	29,024
21	Class peaks less Capacity of minimum system	-	-	-	4	3,616	14	-	13	41	-	3,689
22	**Shares of Total**	0.00%	0.00%	0.00%	0.12%	98.02%	0.37%	0.00%	0.36%	1.12%	0.00%	100.00%
23												
24	Total number of transformers on system											3,628
25	Transfomer capacity- kVa											10
26	Assumed power factor											80%
27	Total Capacity of Transformer minimum system											29,024
28	Number of customers	5,159	29	938	1	392	1	13			4	6,538
29	Capacity per Customer of Transformer minimum system- kW											4.44
30												

D3

Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026
Transformers Classification

Transformers Minimum Size Component

Line	Minimum Size	Minimum Size	Cost for Minimum Size	Total Cost Minimum Size	Number	Replacement Cost	Minimum Size Component
1	TPM10 CSP	10 kVA	1,331	4,828,578	3,628	5,975,094	80.8%
2	Prior Study						74.3%
3	Minimum Size Component						**77.5%**
4							

Transformers Unit Costs

5	6 Description	Description		Cost	Install	Total	Quantity	Total Cost
7	**Line Transformers**							
8	TPM1.5	1.5 - KVA		$950	$281	$1,231	8	9,847
9	TPM5	5 - KVA		$995	$281	$1,276	171	218,182
10	TPM7.5	7.5 - KVA		$995	$281	$1,276	14	17,863
11	TPM10 CSP	10 - KVA	3/2024	$1,050	$281	$1,331	1,075	1,430,739
12	TPM15 CSP	15- KVA	3/2024	$1,695	$281	$1,976	1,248	2,465,948
13	TPM25 CSP	25- KVA	10/2022	$1,935	$281	$2,216	429	950,630
14	TPM37.5 Conv	37.5- KVA	10/2022	$2,715	$281	$2,996	120	359,510
15	TPM50 Conv	50- KVA		$1,575	$281	$1,856	51	94,652
16	TPM75 Conv	75- KVA		$2,050	$281	$2,331	29	67,597
17	TPM100 Conv	100- KVA	3/2024	$3,910	$281	$4,191	30	125,728
18	TPM167 Conv	167 - KVA pole Mount		$3,675	$281	$3,956	2	7,912
19	TPM250 Conv	250 - KVA pole Mount		$4,695	$281	$4,976		-
20	TPM333 Conv	333 - KVA pole Mount		$5,750	$281	$6,031		-
21	TPM333 Conv (3 ph)	333 - KVA pole Mount		$5,750	$281	$6,031	2	12,062
22								
23	**Pad-Mounted Transformers- 1-Phase**							
24	TPD10			$1,415	$1,415	$478	8	3,820
25	TPD15		Aug-24	$1,485	$3,795	$478	99	47,278
26	TPD25		Oct-22	$1,625	$5,415	$478	198	94,557
27	TPD37			$1,795	$1,795	$478	20	9,551
28	TPD50		Aug-23	$2,125	$2,807	$478	67	31,997
29	TPD75			$2,495	$2,495	$478	11	5,253
30	TPD167			$4,250	$22,550	$478	1	478
31								
32	**Pad-Mounted Transformers- 3 Phase**							
33	TPD45			$5,925	$5,925	$478	4	1,910
34	TPD112.5		Jun-24	$6,495	$19,985	$478	9	4,298
35	TPD150			$7,150	$7,150	$478	17	8,119
36	TPD225			$7,995	$7,995	$478	5	2,388
37	TPD300	12/1/2023 quote		$9,175	$29,100	$478	6	2,865
38	TPD500		Feb-24	$12,100	$34,045	$478	1	478
39	TPD1000			$18,985	$18,985	$478	1	478
40	TPD1500		Feb-23	$25,625	$58,735	$478	2	955
							3,628	5,975,094

D4

Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026
Service Costs

	Rate Class	Replacement Cost	Customers	Services Cost
1	Sch. 1- RS	$766	5,159	3,952,747
2	Sch. 2- RSAE	$766	29	22,346
3	Sch. 3- NRS	$766	938	718,786
4	Sch. 3- NRH	$766	1	766
5	Sch. 4- CS	$1,602	392	627,903
6	Sch. 4- CSH	$1,602	1	1,602
7	Sch. 5- IS	$1,602	13	21,357
8	Sch. 6- MSL			0
9	Sch. 7- POL			0
10	Sch. 8- EU		4	0
11	**Total Service Cost**		**6,538**	**5,345,508**
12				
13	Sch. 1- RS			
14	Residential Overhead	$514	75%	385
15	Residential Underground	$1,523	25%	381
16		$766	100%	766
17	Sch. 4- CS			
18	Large Commercial Overhead	$1,399	85%	1,189
19	Large Commercial Underground	$2,752	15%	413
20		$1,602	100%	1,602

D5

Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026
Meter Costs

		Customers	Material	Installation	Other Equipment (with Installation)	Total Cost Per Meter	Total Meter Cost	
1	Sch. 1- RS	5,159	$305	$55		$360	1,857,300	60.18%
2	Sch. 2- RSAE	29	$305	$55		$360	10,500	0.34%
3	Sch. 3- NRS	938	$305	$55		$360	337,740	10.94%
4	Sch. 3- NRH	1	$305	$55		$360	360	0.01%
5	Sch. 4- CS	392	$875	$55	$784	$1,714	671,990	21.77%
6	Sch. 4- CSH	1	$875	$55	$784	$1,714	1,714	0.06%
7	Sch. 5- IS	13	$11,924			$11,924	158,987	5.15%
8	Sch. 6- MSL	0					0	0.00%
9	Sch. 7- POL	0					0	0.00%
10	Sch. 8- EU	4	$11,924			$11,924	47,696	1.55%
11		6,538					3,086,287	100.00%
12								
13	(A) Includes Meter, as well as CT, PT and other equipment if applicable							
14								

D6

Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026
Customer Deposits and Advances; Uncollectible Accounts

		Revenue	% Residential	% Commercial	Write-Offs	Write-Offs	Deposits
1	Sch. 1- RS	6,779,723	99.3%		17,460	87.0%	69,887
2	Sch. 2- RSAE	49,799	0.7%		128	0.6%	513
3	Sch. 3- NRS	770,904		13.4%	332	1.7%	6,802
4	Sch. 3- NRH	2,054		0.0%	1	0.0%	18
5	Sch. 4- CS	3,104,525		53.9%	1,339	6.7%	27,394
6	Sch. 4- CSH	1,536		0.0%	1	0.0%	14
7	Sch. 5- IS	1,778,551		30.9%	767	3.8%	15,694
8	Sch. 6- MSL	19,185				0.0%	
9	Sch. 7- POL	81,665		1.4%	35	0.2%	721
10	Sch. 8- EU	17,863		0.3%	8	0.0%	158
11		12,605,805	100.0%	100.0%	20,071	100.0%	121,200
12				5,757,098			

Year	Residential	Commercial
2024	10,249	7
2023	18,174	4,210
2022	17,712	81
2021	38,989	1,172
2020	10,297	13,964
2019	9,451	11
2018	34,023	1,359
2017	11,098	1,028
2016	8,299	516
	158,291	22,347
Average	17,588	2,483

	Residential	Commercial	Total
2024 Deposits	70,400	50,800	121,200
Customers	322	72	394

Wellsboro Electric Company
Embedded Cost of Service Study (ECOSS)
FPFTY Ending December 31, 2026
Index to Class Cost of Service Study

Line	SCHEDULE	DESCRIPTION
1	E	Index to Class Cost of Service Study
2	E-1	Summary of Results
3	E-1A	Class Allocations- Total
4	E-1B	Revenue Requirement By Functional Classification
5	E-1C	Customer-Related Costs In Revenue Requirement
6	E-2	Funtionalization
7	E-3	Classification
8	E-4A	Class Allocation- Primary Demand
9	E-4B	Class Allocation- Secondary Demand
10	E-4C	Class Allocation- Secondary Customer
11	E-4D	Class Allocation- Billing Customer
12	E-5A	Allocator Assignments
13	E-5B	Functionalization Factors
14	E-5C	Classification Factors
15	E-5D	Class Allocation Factors

Sum
Summary of Results
Tot
E-1

Wellsboro Electric Company
Embedded Cost of Service Study (ECOSS)
FPFTY Ending December 31, 2026
Summary of Results

Line	Account	No.	Balance	RS	RSAE	NRS	NRH	CS	CSH	IS	MSL	POL	EX
1	Distribution Revenue		6,401,996	3,370,741	24,594	498,637	676	1,522,475	1,028	880,020	13,496	81,371	8,957
2	Forfeited Discounts		31,122	27,073	199	516	1	2,076	1	1,189	0	55	12
3	Other Revenue		296,518	149,468	1,751	16,447	116	73,920	235	53,366	216	807	190
4	**Total Revenue**		6,729,636	3,547,282	26,544	515,600	794	1,598,472	1,264	934,576	13,712	82,233	9,159
5													
6	Expenses		6,554,565	3,888,535	35,071	549,279	2,051	1,284,977	3,966	759,003	7,527	16,840	7,317
7	Net income		175,071	(341,253)	(8,527)	(33,679)	(1,256)	313,495	(2,702)	175,573	6,186	65,393	1,842
8													
9	Rate Base		25,857,280	14,330,403	143,611	1,883,819	9,415	5,706,466	19,138	3,491,939	111,717	138,165	22,606
10													
11	Return on Rate Base		0.68%	(2.38%)	(5.94%)	(1.79%)	(13.34%)	5.49%	(14.12%)	5.03%	5.54%	47.33%	8.15%
12	*Relative*		*1.00 x*	*(3.52) x*	*(8.77) x*	*(2.64) x*	*(19.71) x*	*8.11 x*	*(20.85) x*	*7.43 x*	*8.18 x*	*69.90 x*	*12.03 x*
13	Revenue Requirement		9,629,025	5,619,174	52,736	775,982	3,253	1,947,887	6,423	1,165,324	19,762	28,537	9,946
14	*% Total*		*100.0%*	*58.4%*	*0.5%*	*8.1%*	*0.0%*	*20.2%*	*0.1%*	*12.1%*	*0.2%*	*0.3%*	*0.1%*
15	Operating expenses		4,159,626	2,556,765	22,510	371,098	1,300	752,741	2,446	438,293	3,531	6,765	4,176
16	Depreciation expense		1,939,404	1,083,370	10,658	144,200	688	428,719	1,416	260,334	2,732	4,716	2,569
17	Regulatory Commission Expenses		153,393	84,536	849	11,045	56	34,737	116	21,099	316	482	157
18	General taxes / Other		44,148	24,330	244	3,179	16	9,998	33	6,073	91	139	45
19	Uncollectibles expense		20,000	17,398	128	331	1	1,334	1	764	0	35	8
20	GRT		548,782	321,115	2,996	44,782	185	110,442	365	65,535	1,153	1,633	575
21			6,865,352	4,087,515	37,387	574,636	2,247	1,337,970	4,377	792,099	7,822	13,770	7,529
22	Pre-tax income		2,763,673	1,531,659	15,349	201,346	1,006	609,917	2,046	373,225	11,941	14,767	2,416
23	Income taxes		648,547	359,432	3,602	47,250	236	143,128	480	87,584	2,802	3,465	567
24	Net income		2,115,125	1,172,227	11,747	154,096	770	466,789	1,566	285,641	9,138	11,302	1,849
25													
26	Return on Rate Base		8.18%	8.18%	8.18%	8.18%	8.18%	8.18%	8.18%	8.18%	8.18%	8.18%	8.18%
27													
28	Revenue Increase Required		2,899,388	2,071,892	26,192	260,383	2,459	349,415	5,159	230,748	6,050	(53,695)	787
29	Revenue Increase %		45.29%	61.47%	106.50%	52.22%	363.50%	22.95%	501.84%	26.22%	44.83%	(65.99%)	8.78%

Total
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Tot
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Line	Account	No.	Balance		RS	RSAE	NRS	NRH	CS	CSH	IS	MSL	POL	EX
1	**I. ELECTRIC PLANT IN SERVICE**													
2	INTANGIBLE PLANT													
3	EDI Software	303	284,588	.	224,575	1,270	40,838	44	17,064	44	580	0	0	174
4	Total INTANGIBLE Plant		284,588	.	224,575	1,270	40,838	44	17,064	44	580	0	0	174
5														
6	**C. TRANSMISSION PLANT**													
7	Transmission Plant	361	0	.	0	0	0	0	0	0	0	0	0	0
8	Total TRANSMISSION Plant	350-359	0	.	0	0	0	0	0	0	0	0	0	0
9														
10	**D. DISTRIBUTION PLANT**													
11	Land & Land Rights	360	178,334	.	81,941	1,096	7,527	78	47,673	162	39,258	120	369	110
12	Structures and improvements	361	0	.	0	0	0	0	0	0	0	0	0	0
13	Station Equipment	362	3,992,800	.	1,834,608	24,545	168,528	1,753	1,067,372	3,629	878,966	2,682	8,255	2,462
14	Poles, Tower & Fixtures	364	14,933,172	.	7,499,446	90,771	800,278	6,223	3,737,105	12,627	2,740,757	9,153	28,174	8,637
15	OH Conductors & Devices	365	6,804,947	.	3,401,508	41,635	357,577	2,868	1,725,404	5,834	1,248,945	4,239	13,049	3,887
16	UG Conduits and Conductors	366	1,038,449	.	567,115	6,605	63,532	445	265,660	895	131,107	643	1,980	466
17	Line Transformers	368	3,365,587	.	2,063,802	11,667	375,291	1,293	897,472	3,221	0	2,756	8,485	1,600
18	Services	369	2,486,089	.	1,838,344	10,393	334,293	356	292,025	745	9,933	0	0	0
19	Meters	370	1,041,481	.	626,754	3,543	113,972	121	226,766	578	53,651	0	0	16,095
20	Install. Customers' premises	371	519,618	.	410,043	2,318	74,564	79	31,156	79	1,060	0	0	318
21	Street Lighting & Signal	373	125,272	.	0	0	0	0	0	0	0	62,636	62,636	0
22	Total DISTRIBUTION Plant	360-373	34,485,748	.	18,323,559	192,574	2,295,562	13,218	8,290,633	27,772	5,103,676	82,230	122,948	33,575
23														
24	**E. GENERAL PLANT**													
25	General Plant	389	9,778,618	.	6,062,712	52,552	889,585	2,988	1,739,095	5,616	989,128	8,965	16,219	11,760
26	Communication Equip	398	117,901	.	73,098	634	10,726	36	20,968	68	11,926	108	196	142
27	Total GENERAL Plant	389-399	9,896,519	.	6,135,810	53,185	900,311	3,024	1,760,063	5,684	1,001,054	9,073	16,415	11,901
28														
29	**TOTAL UTILITY PLANT**		44,666,856	.	24,683,945	247,029	3,236,711	16,285	10,067,760	33,500	6,105,310	91,302	139,363	45,651
30														

Total
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Line	Account	No.	Balance		RS	RSAE	NRS	NRH	CS	CSH	IS	MSL	POL	EX
31	**II. DEPRECIATION RESERVE**													
32	Intangible Plant		284,588	.	224,575	1,270	40,838	44	17,064	44	580	0	0	174
33	Transmission Plant		0	.	0	0	0	0	0	0	0	0	0	0
34	Structures and improvements		0	.	0	0	0	0	0	0	0	0	0	0
35	Station Equipment		3,892,596	.	1,788,566	23,929	164,299	1,709	1,040,585	3,538	856,908	2,614	8,048	2,400
36	Poles, Towers and Fixtures		5,102,743	.	2,562,600	31,017	273,459	2,126	1,276,988	4,315	936,531	3,128	9,627	2,951
37	OH Conductors and Devices		2,322,844	.	1,161,092	14,212	122,058	979	588,960	1,992	426,323	1,447	4,454	1,327
38	UG Conduits and Conductors		779,669	.	425,791	4,959	47,700	334	199,458	672	98,436	483	1,486	350
39	Line Transformers		1,697,284	.	1,040,787	5,884	189,261	652	452,600	1,624	0	1,390	4,279	807
40	Services		1,472,321	.	1,088,711	6,155	197,976	211	172,944	441	5,882	0	0	0
41	Meters		787,559	.	473,946	2,679	86,185	92	171,478	437	40,570	0	0	12,171
42	Install. Customers' premises		115,728	.	91,324	516	16,607	18	6,939	18	236	0	0	71
43	Street Lighting & Signal		(63,042)	.	0	0	0	0	0	0	0	(31,521)	(31,521)	0
44	General Plant		2,928,774	.	1,815,830	15,740	266,438	895	520,873	1,682	296,252	2,685	4,858	3,522
45	Total DEPRECIATION RESE	108	19,321,064	.	10,673,222	106,361	1,404,820	7,060	4,447,890	14,763	2,661,718	(19,774)	1,231	23,773
46														
47	**III. OTHER RATE BASE ITEMS**													
48	Cash Working Capital	131	517,744	.	317,740	2,807	45,717	162	94,148	306	54,937	501	910	516
49	CWIP	131	0	.	0	0	0	0	0	0	0	0	0	0
50	Materials & Supplies	255	247,983	.	148,411	1,286	21,786	77	48,975	158	26,080	238	441	531
51	Customer Deposits		(195,713)	.	(112,853)	(829)	(10,984)	(29)	(44,236)	(22)	(25,342)	0	(1,164)	(255)
52	ADIT	154	(38,728)	.	(21,343)	(214)	(2,789)	(14)	(8,770)	(29)	(5,327)	(80)	(122)	(40)
53	Accrued Pension / OPEB	182	(19,798)	.	(12,274)	(106)	(1,801)	(6)	(3,521)	(11)	(2,003)	(18)	(33)	(24)
54	Total OTHER RATE BASE	131-283	511,488	.	319,681	2,943	51,929	190	86,596	402	48,346	641	34	729
55														
56	**TOTAL RATE BASE**		25,857,280	.	14,330,403	143,611	1,883,819	9,415	5,706,466	19,138	3,491,939	111,717	138,165	22,606
57														

Total
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Line	Account	No.	Balance		RS	RSAE	NRS	NRH	CS	CSH	IS	MSL	POL	EX
58	**I. OPERATING AND MAINTENANCE EXPENSES**													
59	**B. TRANSMISSION EXPENSE**													
60	Transmission Expense		0	.	0	0	0	0	0	0	0	0	0	0
61	Total TRANSMISSION Expe		0		0	0	0	0	0	0	0	0	0	0
62														
63	**C. DISTRIBUTION EXPENSE**													
64	Ops Supv & Engineering	580	0	.	0	0	0	0	0	0	0	0	0	0
65	Station Expenses	582	0	.	0	0	0	0	0	0	0	0	0	0
66	OH Line Expenses	583	6,020	.	3,009	37	316	3	1,526	5	1,105	4	12	3
67	Street Lighting Expenses	585	267	.	0	0	0	0	0	0	0	134	134	0
68	Meter Expenses	586	39,903	.	24,013	136	4,367	5	8,688	22	2,056	0	0	617
69	Customer Install. expense	587	267	.	211	1	38	0	16	0	1	0	0	0
70	Misc. Distribution Expenses	588	285,688	.	146,787	1,813	15,239	125	75,535	256	45,033	186	573	141
71	Rents	589	35,300	.	19,508	206	2,429	13	7,836	26	5,181	18	56	26
72	Maint Supv & Engineering	590	101,784	.	51,062	624	5,381	43	26,073	88	18,012	152	285	63
73	Maint of Station Equip	592	18,557	.	8,527	114	783	8	4,961	17	4,085	12	38	11
74	Maint of OH Lines	593	985,327	.	492,524	6,029	51,776	415	249,831	845	180,842	614	1,889	563
75	Maint of UG Lines	594	40,313	.	22,016	256	2,466	17	10,313	35	5,090	25	77	18
76	Maint of Line Transformers	595	8,064	.	4,945	28	899	3	2,150	8	0	7	20	4
77	Maint of Lighting	596	942	.	0	0	0	0	0	0	0	471	471	0
78	Maint of Misc. Plant	599	80,194	.	43,828	466	5,430	30	18,083	60	11,791	182	268	56
79	Total DISTR. O&M EXP.	500-599	1,602,629	.	816,430	9,710	89,126	663	405,012	1,361	273,196	1,805	3,823	1,502
80	Distribution Expense		1,602,629		816,430	9,710	89,126	663	405,012	1,361	273,196	1,805	3,823	1,502
81	**D. CUSTOMER ACCOUNTS AND SERVICE**													
82	Supervision	901	0	.	0	0	0	0	0	0	0	0	0	0
83	Meter Reading Exp	902	16,544	.	9,956	56	1,810	2	3,602	9	852	0	0	256
84	Customer Records & Coll	903	1,047,510	.	826,616	4,673	150,316	160	62,807	160	2,136	0	0	641
85	Uncollectible Accounts	904	20,000	.	17,398	128	331	1	1,334	1	764	0	35	8
86	Subtotal - Cust. Accts. Exp.	901-905	1,084,054	.	853,970	4,857	152,457	163	67,744	170	3,753	0	35	904
87														
88	Customer Assistance	908	9,737	.	7,684	43	1,397	1	584	1	20	0	0	6
89	OPEN	916	0	.	0	0	0	0	0	0	0	0	0	0
90	Subtotal - Cust. Svce. & Info.	908-916	9,737	.	7,684	43	1,397	1	584	1	20	0	0	6
91	Total CUST. ACCT. & SERV	901-919	1,093,791	.	861,654	4,901	153,855	165	68,328	172	3,773	0	35	910
92														

Total
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Line	Account	No.	Balance		RS	RSAE	NRS	NRH	CS	CSH	IS	MSL	POL	EX
93	**E. ADMINISTRATIVE AND GENERAL**													
94	Admin. & Gen'l. Salaries	920	911,229	.	564,959	4,897	82,897	278	162,059	523	92,173	835	1,511	1,096
95	Office Supplies & Expenses	921	109,710	.	68,020	590	9,981	34	19,512	63	11,097	101	182	132
96	Outside Services Employed	923	154,525	.	89,934	845	12,434	52	31,839	105	18,524	225	369	198
97	Property Insurance	924	61,410	.	33,843	340	4,422	22	13,907	46	8,447	126	193	63
98	Employee Pensions & Benefits	926	0	.	0	0	0	0	0	0	0	0	0	0
99	Regulatory Comm. Expense	928	153,393	.	85,012	852	11,175	56	33,852	114	20,715	663	820	134
100	Misc. General Expense	930	110,581	.	64,358	605	8,898	37	22,784	75	13,256	161	264	142
101	Rents	931	2,200	.	1,364	12	200	1	391	1	223	2	4	3
102	Maint General Property	932	133,551	.	73,601	740	9,617	49	30,244	101	18,370	275	419	137
103	Total A&G Expense	920-932	1,636,599	.	981,092	8,880	139,624	530	314,588	1,028	182,805	2,388	3,761	1,905
104														
105	TOTAL OPERATING EXPE		4,333,019	.	2,659,175	23,490	382,605	1,357	787,927	2,561	459,773	4,193	7,620	4,317
106														
107	**II. DEPRECIATION EXPENSE**													
108	Intangible Plant		0	.	0	0	0	0	0	0	0	0	0	0
109	Station Equipment		252,375	.	115,961	1,551	10,652	111	67,466	229	55,557	170	522	156
110	Poles, Towers and Fixtures		509,675	.	255,959	3,098	27,314	212	127,549	431	93,543	312	962	295
111	OH Conductors and Devices		263,041	.	131,483	1,609	13,822	111	66,694	226	48,277	164	504	150
112	UG Conduits and Conductors		44,951	.	24,548	286	2,750	19	11,500	39	5,675	28	86	20
113	Line Transformers		116,555	.	71,472	404	12,997	45	31,081	112	0	95	294	55
114	Services		95,347	.	70,505	399	12,821	14	11,200	29	381	0	0	0
115	Meters		79,809	.	48,028	272	8,734	9	17,377	44	4,111	0	0	1,233
116	Install. Customers' premises		53,884	.	42,521	240	7,732	8	3,231	8	110	0	0	33
117	Street Lighting & Signal		2,971	.	0	0	0	0	0	0	0	1,485	1,485	0
118	General Plant		520,797	.	322,892	2,799	47,378	159	92,622	299	52,680	477	864	626
119	Total DEPRECIATION Exp.	403	1,939,404	.	1,083,370	10,658	144,200	688	428,719	1,416	260,334	2,732	4,716	2,569
120														
121	**III. TAXES and OTHER**													
122	**A. GENERAL TAXES**													
123	Payroll related	408	0	.	0	0	0	0	0	0	0	0	0	0
124	PURTA, Real estate	408.16	43,311	.	23,869	240	3,119	16	9,808	33	5,957	89	136	44
125	Capital stock		0	.	0	0	0	0	0	0	0	0	0	0
126	Other	408	837	.	461	5	60	0	190	1	115	2	3	1
127	Subtotal - General Taxes		44,148	.	24,330	244	3,179	16	9,998	33	6,073	91	139	45
128														
129	**B. GROSS RECEIPTS TAX**													
130	Gross Receipts tax		377,718	.	198,874	1,451	29,420	40	89,826	61	51,921	796	4,801	528
131	Subtotal- Gross Receipts tax		377,718	.	198,874	1,451	29,420	40	89,826	61	51,921	796	4,801	528
132														

Total
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Tot
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Line	Account	No.	Balance		RS	RSAE	NRS	NRH	CS	CSH	IS	MSL	POL	EX
133	**B. FEDERAL / STATE INCOME TAXES**													
134	State Income Tax Expense		(86,033)	.	(47,544)	(476)	(6,234)	(31)	(19,392)	(65)	(11,760)	(176)	(268)	(88)
135	Federal Income Tax Expense		(53,690)	.	(29,670)	(297)	(3,891)	(20)	(12,101)	(40)	(7,339)	(110)	(168)	(55)
136	Subtotal - Fed / State Inc Tax	409-411	(139,723)	.	(77,214)	(773)	(10,125)	(51)	(31,493)	(105)	(19,098)	(286)	(436)	(143)
137	Total TAXES	408-411	282,143	.	145,990	923	22,474	5	68,331	(11)	38,896	602	4,504	431
138														
139	**TOTAL EXPENSES**		6,554,565	.	3,888,535	35,071	549,279	2,051	1,284,977	3,966	759,003	7,527	16,840	7,317
140														
141	**IV. OPERATING REVENUES at Present Rates**													
142	Distribution Revenue		6,401,996	.	3,370,741	24,594	498,637	676	1,522,475	1,028	880,020	13,496	81,371	8,957
143	Forfeited Discounts		31,122	.	27,073	199	516	1	2,076	1	1,189	0	55	12
144	Rent For Electric Property		273,619	.	137,412	1,663	14,663	114	68,475	231	50,219	168	516	158
145	Other Electric Revenues		22,899	.	12,057	88	1,784	2	5,446	4	3,148	48	291	32
146	Total REVENUES		6,729,636	.	3,547,282	26,544	515,600	794	1,598,472	1,264	934,576	13,712	82,233	9,159
147														
148	TOTAL EXPENSES		6,554,565	.	3,888,535	35,071	549,279	2,051	1,284,977	3,966	759,003	7,527	16,840	7,317
149	**V. NET INCOME at Present Rates**		175,071	.	(341,253)	(8,527)	(33,679)	(1,256)	313,495	(2,702)	175,573	6,186	65,393	1,842
150														
151	**SUMMARY REPORT**													
152	OPERATING REVENUES													
153	Utility Revenues	440-446	6,433,118	.	3,397,814	24,793	499,153	678	1,524,552	1,029	881,210	13,496	81,425	8,969
154	Other Operating Revenues	450-456	296,518	.	149,468	1,751	16,447	116	73,920	235	53,366	216	807	190
155	Total Operating Revenues		6,729,636	.	3,547,282	26,544	515,600	794	1,598,472	1,264	934,576	13,712	82,233	9,159
156														
157	OPERATING EXPENSES													
158	Distribution / Transmission	580-599	1,602,629	.	816,430	9,710	89,126	663	405,012	1,361	273,196	1,805	3,823	1,502
159	Customer Acctg & Service	901-919	1,093,791	.	861,654	4,901	153,855	165	68,328	172	3,773	0	35	910
160	Admin & General	920-932	1,636,599	.	981,092	8,880	139,624	530	314,588	1,028	182,805	2,388	3,761	1,905
161	Total Operating Expenses		4,333,019	.	2,659,175	23,490	382,605	1,357	787,927	2,561	459,773	4,193	7,620	4,317
162														
163	Depreciation Expense	403	1,939,404	.	1,083,370	10,658	144,200	688	428,719	1,416	260,334	2,732	4,716	2,569
164	Taxes Other Than Income	408	421,866	.	223,204	1,696	32,599	56	99,824	94	57,994	887	4,939	574
165	INCOME BEFORE INCOME		35,348	.	(418,467)	(9,300)	(43,804)	(1,307)	282,002	(2,807)	156,475	5,900	64,957	1,699
166	Income Taxes	409-411	(139,723)	.	(77,214)	(773)	(10,125)	(51)	(31,493)	(105)	(19,098)	(286)	(436)	(143)
167	**NET INCOME**		175,071	.	(341,253)	(8,527)	(33,679)	(1,256)	313,495	(2,702)	175,573	6,186	65,393	1,842
168														
169	**RATE BASE**		25,857,280	.	14,330,403	143,611	1,883,819	9,415	5,706,466	19,138	3,491,939	111,717	138,165	22,606
170	Return on Rate Base		0.68%											
171														

Total
Class Allocations- Total
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E-1A

Wellsboro Electric Company
Embedded Cost of Service Study (ECOSS)
FPFTY Ending December 31, 2026
Class Allocations- Total

Line	Account	No.	Balance		RS	RSAE	NRS	NRH	CS	CSH	IS	MSL	POL	EX
172	**REVENUE REQUIREMENTS**													
173	Target Rate of Return		8.1800%		8.1800%	8.1800%	8.1800%	8.1800%	8.1800%	8.1800%	8.1800%	8.1800%	8.1800%	8.1800%
174														
175	Rate Base		25,857,280	.	14,330,403	143,611	1,883,819	9,415	5,706,466	19,138	3,491,939	111,717	138,165	22,606
176														
177	Operating expenses		4,159,626	.	2,556,765	22,510	371,098	1,300	752,741	2,446	438,293	3,531	6,765	4,176
178	Uncollectibles expense		20,000	.	17,398	128	331	1	1,334	1	764	0	35	8
179	Depreciation expense		1,939,404	.	1,083,370	10,658	144,200	688	428,719	1,416	260,334	2,732	4,716	2,569
180	Regulatory Commission Expenses		153,393	.	84,536	849	11,045	56	34,737	116	21,099	316	482	157
181	General taxes / Other		44,148	.	24,330	244	3,179	16	9,998	33	6,073	91	139	45
182	Subtotal- Operating Costs to recover		6,316,570	.	3,766,400	34,390	529,854	2,062	1,227,528	4,012	726,564	6,669	12,137	6,955
183														
184	Target Return on Rate Base- After tax		2,115,125		1,172,227	11,747	154,096	770	466,789	1,566	285,641	9,138	11,302	1,849
185														
186	Income taxes to recover		648,547	.	359,432	3,602	47,250	236	143,128	480	87,584	2,802	3,465	567
187														
188	Subtotal- Rev Req before GRT		9,080,243	.	5,298,059	49,740	731,200	3,068	1,837,446	6,058	1,099,788	18,609	26,904	9,371
189	GRT needed		548,782	.	321,115	2,996	44,782	185	110,442	365	65,535	1,153	1,633	575
190	**TOTAL REVENUE REQUIREMEN**		9,629,025	.	5,619,174	52,736	775,982	3,253	1,947,887	6,423	1,165,324	19,762	28,537	9,946
191														
192	Revenue at Present rates		6,729,636		3,547,282	26,544	515,600	794	1,598,472	1,264	934,576	13,712	82,233	9,159
193	Revenue Excess (Deficiency)		(2,899,388)		(2,071,892)	(26,192)	(260,383)	(2,459)	(349,415)	(5,159)	(230,748)	(6,050)	53,695	(787)
194														

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Wellsboro Electric Company
Embedded Cost of Service Study (ECOSS)
FPFTY Ending December 31, 2026
TOTAL REVENUE REQUIREMENT

	Account Description	Total Dollars	RS	RSAE	NRS	NRH	CS	CSH	IS	MSL	POL	EX
1	**Demand-related**											
2	Primary	5,203,351	2,390,780	31,988	219,596	2,285	1,391,004	4,730	1,145,517	3,494	10,749	3,208
3	Secondary	630,468	321,616	4,303	29,541	408	270,478	954	(13)	780	2,401	(0)
4		5,833,819	2,712,396	36,291	249,137	2,693	1,661,482	5,684	1,145,504	4,274	13,150	3,208
5	NCP-Primary	20,036	9,206	123	846	9	5,356	18	4,411	13	41	12
6	Per kW / month-Demand	24.26	24.55	24.55	24.55	25.51	25.85	26.01	21.64	26.47	26.46	21.64
7												
8	kWh-Meter	105,861,774	44,812,773	397,781	4,732,166	6,256	29,056,715	7,216	26,746,293	0	0	102,572
9	Per kWh-Meter	$0.05511	$0.06053	$0.09123	$0.05265	$0.43039	$0.05718	$0.78770	$0.04283	#DIV/0!	#DIV/0!	$0.03127
10												
11	**Customer-related**											
12	Secondary	1,177,355	893,250	5,050	162,436	173	83,718	214	1,012	15,480	15,479	544
13	Billing	2,617,851	2,013,528	11,395	364,410	388	202,688	525	18,807	8	(92)	6,194
14		3,795,205	2,906,778	16,445	526,845	561	286,406	739	19,819	15,489	15,387	6,738
15	Number of Bills	78,454	61,910	350	11,258	12	4,704	12	160	0	0	48
16	Per bill	$48.37	$46.95	$46.98	$46.80	$46.72	$60.89	$61.58	$123.87	-	-	$140.37
17												
18	Total revenue requirement	9,629,025	5,619,174	52,736	775,982	3,253	1,947,887	6,423	1,165,324	19,762	28,537	9,946
19												
20	**Demand-related**											
21	Primary	$21.64	$21.64	$21.64	$21.64	$21.64	$21.64	$21.64	$21.64	$21.64	$21.63	$21.64
22	Secondary	$2.62	$2.91	$2.91	$2.91	$3.86	$4.21	$4.36	($0.00)	$4.83	$4.83	($0.00)
23		$24.26	$24.55	$24.55	$24.55	$25.51	$25.85	$26.01	$21.64	$26.47	$26.46	$21.64

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Wellsboro Electric Company
Embedded Cost of Service Study (ECOSS)
FPFTY Ending December 31, 2026
TOTAL REVENUE REQUIREMENT

	Account Description		Total Dollars	RS	RSAE	NRS	NRH	CS	CSH	IS	MSL	POL	EX
1	Services, cost	Acct 369	2,486,089	1,838,344	10,393	334,293	356	292,025	745	9,933	0	0	0
2	Services, Acc Depr	Portion Acct 108	(1,472,321)	(1,088,711)	(6,155)	(197,976)	(211)	(172,944)	(441)	(5,882)	0	0	0
3	Meters, cost	Acct 370	1,041,481	626,754	3,543	113,972	121	226,766	578	53,651	0	0	16,095
4	Meters, Acc Depr	Portion Acct 108	(787,559)	(473,946)	(2,679)	(86,185)	(92)	(171,478)	(437)	(40,570)	0	0	(12,171)
5	ADIT- Service / Meter	Portion Acct 154	(4,068)	(2,871)	(16)	(545)	(1)	(549)	(1)	(66)	0	0	(19)
6	Service / Meter-Related Rate Base		1,263,622	899,569	5,086	163,559	174	173,820	443	17,065	0	0	3,905
7	Rate of return on rate base		8.18%	8.18%	8.18%	8.18%	8.18%	8.18%	8.18%	8.18%	8.18%	8.18%	8.18%
8	Return on Service / Meter rate base		103,364	73,585	416	13,379	14	14,218	36	1,396	0	0	319
9	Income tax gross-up		31,694	22,563	128	4,102	4	4,360	11	428	0	0	98
10	GRT gross-up		8,186	5,828	33	1,071	1	1,117	3	109	0	0	26
11	Customer-charge return component		143,244	101,975	576	18,552	20	19,695	50	1,933	0	0	443
12													
13	Meter expenses	Acct 586	39,903	24,013	136	4,367	5	8,688	22	2,056	0	0	617
14	Meter reading expenses	Acct 902	16,544	9,956	56	1,810	2	3,602	9	852	0	0	256
15	Service / Meter / EDI depr / amc	Portion Acct 403	175,156	118,533	670	21,555	23	28,577	73	4,492	0	0	1,233
16	Customer records and collection	Acct 903	1,047,510	826,616	4,673	150,316	160	62,807	160	2,136	0	0	641
17	Customer assistance	Acct 908	9,737	7,684	43	1,397	1	584	1	20	0	0	6
18	Employee benefits, taxes		0	0	0	0	0	0	0	0	0	0	0
19	Customer-charge expense component		1,288,851	986,802	5,579	179,445	191	104,259	266	9,556	0	0	2,753
20													
21	Customer-charge expense component		1,432,095	1,088,778	6,155	197,997	211	123,953	316	11,489	0	0	3,196
22													
23	Number of Bills		78,454	61,910	350	11,258	12	4,704	12	160	0	0	48
24													
25	**Customer-charge Components**		**$18.25**	**$17.59**	**$17.59**	**$17.59**	**$17.59**	**$26.35**	**$26.35**	**$71.80**	**-**	**-**	**$66.57**
26													
27	Distribution Plant in Service- Cost		34,485,748	18,323,559	192,574	2,295,562	13,218	8,290,633	27,772	5,103,676	82,230	122,948	33,575
28	Services / Meters % of Distribution Plant		10.2%	13.5%	7.2%	19.5%	3.6%	6.3%	4.8%	1.2%	0.0%	0.0%	47.9%
29	ADIT		(38,728)	(21,343)	(214)	(2,789)	(14)	(8,770)	(29)	(5,327)	(80)	(122)	(40)
30													
31	Income tax gross-up		30.66%	30.66%	30.66%	30.66%	30.66%	30.66%	30.66%	30.66%	30.66%	30.66%	30.66%
32	GRT gross-up		6.04%	6.06%	6.02%	6.12%	6.03%	6.01%	6.03%	5.96%	6.20%	6.07%	6.13%

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Wellsboro Electric Company
Embedded Cost of Service Study (ECOSS)
FPFTY Ending December 31, 2026
Funtionalization

Line	Account	No.	Balance	Allocator	Primary	Secondary	Billing		Labor Cost	Labor %
					4	5	6			
1	**I. ELECTRIC PLANT IN SERVICE**									
2	INTANGIBLE PLANT									
3	EDI Software	303	284,588	Bill	0	0	284,588	-		
4	Total INTANGIBLE Plant		284,588		0	0	284,588	-		
5										
6	**C. TRANSMISSION PLANT**							-		
7	Transmission Plant	361	0	Tran	0	0	0	-		
8	Total TRANSMISSION Plant	350-359	0		0	0	0	-		
9										
10	**D. DISTRIBUTION PLANT**									
11	Land & Land Rights	360	178,334	Prim	178,334	0	0	-		
12	Structures and improvements	361	0	Prim	0	0	0	-		
13	Station Equipment	362	3,992,800	Prim	3,992,800	0	0	-		
14	Poles, Tower & Fixtures	364	14,933,172	OH_Cond	12,450,184	2,482,988	0	-		
15	OH Conductors & Devices	365	6,804,947	OH_Cond	5,673,466	1,131,481	0	-		
16	UG Conduits and Conductors	366	1,038,449	UG_Cond	595,569	442,880	0	-		
17	Line Transformers	368	3,365,587	Trans	0	3,365,587	0	-		
18	Services	369	2,486,089	Sec	0	2,486,089	0	-		
19	Meters	370	1,041,481	Bill	0	0	1,041,481	-		
20	Install. Customers' premises	371	519,618	Bill	0	0	519,618	-		
21	Street Lighting & Signal	373	125,272	Sec	0	125,272	0	-		
22	Total DISTRIBUTION Plant	360-373	34,485,748		22,890,353	10,034,297	1,561,098	-		
23										
24	**E. GENERAL PLANT**									
25	General Plant	389	9,778,618	Labor	4,360,516	1,214,242	4,203,861	-		
26	Communication Equip	398	117,901	Labor	52,575	14,640	50,686	-		
27	Total GENERAL Plant	389-399	9,896,519		4,413,091	1,228,882	4,254,547	-		
28										
29	**TOTAL UTILITY PLANT**		44,666,856		27,303,444	11,263,179	6,100,233	-		
30										

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Wellsboro Electric Company
Embedded Cost of Service Study (ECOSS)
FPFTY Ending December 31, 2026
Funtionalization

Line	Account	No.	Balance	Allocator	Primary	Secondary	Billing		Labor Cost	Labor %
					4	5	6			
31	**II. DEPRECIATION RESERVE**									
32	Intangible Plant		284,588	IntanPt	0	0	284,588	-		
33	Transmission Plant		0	TranPt	0	0	0	-		
34	Structures and improvements		0	Prim	0	0	0	-		
35	Station Equipment		3,892,596	Prim	3,892,596	0	0	-		
36	Poles, Towers and Fixtures		5,102,743	OH_Cond	4,254,293	848,450	0	-		
37	OH Conductors and Devices		2,322,844	OH_Cond	1,936,617	386,227	0	-		
38	UG Conduits and Conductors		779,669	UG_Cond	447,154	332,515	0	-		
39	Line Transformers		1,697,284	Trans	0	1,697,284	0	-		
40	Services		1,472,321	Sec	0	1,472,321	0	-		
41	Meters		787,559	Bill	0	0	787,559	-		
42	Install. Customers' premises		115,728	Bill	0	0	115,728	-		
43	Street Lighting & Signal		(63,042)	Sec	0	(63,042)	0	-		
44	General Plant		2,928,774	GenPtxL	1,306,009	363,675	1,259,090	-		
45	Total DEPRECIATION RESE	108	19,321,064		11,836,669	5,037,430	2,446,965	-		
46										
47	**III. OTHER RATE BASE ITEMS**									
48	Cash Working Capital	131	517,744	OpExp_Dist	232,758	65,985	219,001	-		
49	CWIP	131	0	Plant	0	0	0	-		
50	Materials & Supplies	255	247,983	OpExp_Dist	111,484	31,605	104,895	-		
51	Customer Deposits		(195,713)	Bill	0	0	(195,713)	-		
52	ADIT	154	(38,728)	Plant	(23,825)	(9,828)	(5,075)	-		
53	Accrued Pension / OPEB	182	(19,798)	Labor	(8,828)	(2,458)	(8,511)	-		
54	Total OTHER RATE BASE	131-283	511,488		311,588	85,303	114,597	-		
55										
56	**TOTAL RATE BASE**		25,857,280		15,778,363	6,311,053	3,767,865	-		
57			25,857,280							

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Wellsboro Electric Company
Embedded Cost of Service Study (ECOSS)
FPFTY Ending December 31, 2026
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Line	Account	No.	Balance	Allocator	Primary	Secondary	Billing		Labor Cost	Labor %
					4	5	6			
58	**I. OPERATING AND MAINTENANCE EXPENSES**									
59	**B. TRANSMISSION EXPENSE**									
60	Transmission Expense		0	Tran	0	0	0	-	0	0
61	Total TRANSMISSION Expense		0		0	0	0			
62										
63	**C. DISTRIBUTION EXPENSE**									
64	Ops Supv & Engineering	580	0	D-Labor-Op	0	0	0	-	0	0.0%
65	Station Expenses	582	0	Prim	0	0	0	-	0	0.0%
66	OH Line Expenses	583	6,020	OH_Cond	5,019	1,001	0	-	4,098	68.1%
67	Street Lighting Expenses	585	267	Sec	0	267	0	-	182	68.2%
68	Meter Expenses	586	39,903	Bill	0	0	39,903	-	26,981	67.6%
69	Customer Install. expense	587	267	Bill	0	0	267	-	182	68.2%
70	Misc. Distribution Expenses	588	285,688	OH_UG	204,569	81,120	0	-	140,466	49.2%
71	Rents	589	35,300	DistPt	23,431	10,271	1,598	-	0	0.0%
72	Maint Supv & Engineering	590	101,784	D-Labor-Mnt	81,705	19,585	494	-	42,663	41.9%
73	Maint of Station Equip	592	18,557	Prim	18,557	0	0	-	1,924	10.4%
74	Maint of OH Lines	593	985,327	OH_Cond	821,493	163,834	0	-	289,584	29.4%
75	Maint of UG Lines	594	40,313	UG_Cond	23,120	17,193	0	-	4,638	11.5%
76	Maint of Line Transformers	595	8,064	Trans	0	8,064	0	-	3,447	42.7%
77	Maint of Lighting	596	942	Sec	0	942	0	-	641	68.1%
78	Maint of Misc. Plant	599	80,194	DistPt	53,230	23,334	3,630	-	36,073	45.0%
79	Total DISTR. O&M EXP.	500-599	1,602,629		1,231,124	325,612	45,893	-	550,882	
80	Distribution Expense		1,602,629		1,231,124	325,612	45,893	-		
81	**D. CUSTOMER ACCOUNTS AND SERVICE**									
82	Supervision	901	0	None	0	0	0	-	0	0.0%
83	Meter Reading Exp	902	16,544	Bill	0	0	16,544	-	11,261	68.1%
84	Customer Records & Coll	903	1,047,510	Bill	0	0	1,047,510	-	353,116	33.7%
85	Uncollectible Accounts	904	20,000	Bill	0	0	20,000	-	0	0.0%
86	Subtotal - Cust. Accts. Exp.	901-905	1,084,054		0	0	1,084,054	-	364,377	
87										
88	Customer Assistance	908	9,737	Bill	0	0	9,737	-	161	1.7%
89	OPEN	916	0	None	0	0	0	-	0	0.0%
90	Subtotal - Cust. Svce. & Info.	908-916	9,737		0	0	9,737	-	161	
91	Total CUST. ACCT. & SERV.	901-919	1,093,791		0	0	1,093,791	-	364,538	
92									915,420	

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Wellsboro Electric Company
Embedded Cost of Service Study (ECOSS)
FPFTY Ending December 31, 2026
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Line	Account	No.	Balance	Allocator	Primary	Secondary	Billing		Labor Cost	Labor %
					4	5	6			
93	**E. ADMINISTRATIVE AND GENERAL**									
94	Admin. & Gen'l. Salaries	920	911,229	Labor	406,339	113,150	391,740	-		
95	Office Supplies & Expenses	921	109,710	Labor	48,922	13,623	47,165	-		
96	Outside Services Employed	923	154,525	Labor_Pt	81,984	29,201	43,340	-		
97	Property Insurance	924	61,410	Plant	37,779	15,584	8,047	-		
98	Employee Pensions & Benefits	926	0	Labor	0	0	0	-		
99	Regulatory Comm. Expense	928	153,393	Bill	0	0	153,393	-		
100	Misc. General Expense	930	110,581	Labor_Pt	58,669	20,897	31,014	-		
101	Rents	931	2,200	Labor	981	273	946	-		
102	Maint General Property	932	133,551	Plant	82,159	33,892	17,500	-		
103	Total A&G Expense	920-932	1,636,599		716,833	226,621	693,144	-		
104										
105	TOTAL OPERATING EXPENSES		4,333,019		1,947,957	552,233	1,832,829	-		
106										
107	**II. DEPRECIATION EXPENSE**									
108	Intangible Plant		0	IntanPt	0	0	0	-		
109	Station Equipment		252,375	Prim	252,375	0	0	-		
110	Poles, Towers and Fixtures		509,675	OH_Cond	424,929	84,745	0	-		
111	OH Conductors and Devices		263,041	OH_Cond	219,304	43,737	0	-		
112	UG Conduits and Conductors		44,951	UG_Cond	25,780	19,171	0	-		
113	Line Transformers		116,555	Trans	0	116,555	0	-		
114	Services		95,347	Sec	0	95,347	0	-		
115	Meters		79,809	Bill	0	0	79,809	-		
116	Install. Customers' premises		53,884	Bill	0	0	53,884	-		
117	Street Lighting & Signal		2,971	Sec	0	2,971	0	-		
118	General Plant		520,797	GenPtxL	232,236	64,669	223,892	-		
119	Total DEPRECIATION Exp.	403	1,939,404		1,154,624	427,194	357,586	-		
120										
121	**III. TAXES and OTHER**									
122	**A. GENERAL TAXES**									
123	Payroll related	408.3	0	None	0	0	0	-		
124	PURTA, Real estate	408.16	43,311	Plant	26,644	10,991	5,675	-		
125	Capital stock		0	RateBase	0	0	0	-		
126	Other	408.1	837	Plant	515	212	110	-		
127	Subtotal - General Taxes		44,148		27,159	11,204	5,785	-		
128										
129	**B. GROSS RECEIPTS TAX**									
130	Gross Receipts tax		377,718	GRT_RevxT	198,268	69,393	110,058	-		
131	Subtotal- Gross Receipts tax		377,718		198,268	69,393	110,058	-		
132										

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Wellsboro Electric Company
Embedded Cost of Service Study (ECOSS)
FPFTY Ending December 31, 2026
Funtionalization

Line	Account	No.	Balance	Allocator	Primary	Secondary	Billing		Labor Cost	Labor %
					4	5	6			
133	**B. FEDERAL / STATE INCOME TAXES**									
134	State Income Tax Expense		(86,033)	StaTax	(53,985)	(32,048)	0	-		
135	Federal Income Tax Expense		(53,690)	FedTax	(33,690)	(20,000)	0	-		
136	Subtotal - Fed / State Inc Tax	409-411	(139,723)		(87,675)	(52,048)	0	-		
137	Total TAXES	408-411	282,143		137,752	28,548	115,842	-		
138										
139	**TOTAL EXPENSES**		6,554,565		3,240,333	1,007,975	2,306,257	-		
140										
141	**IV. OPERATING REVENUES at Present Rates**									
142	Distribution Revenue		6,401,996	DistBill_RR-PF	3,376,804	1,181,864	1,843,328	-		
143	Forfeited Discounts		31,122	Bill	0	0	31,122	-		
144	Rent For Electric Property		273,619	OH_Cond	228,123	45,496	0	-		
145	Other Electric Revenues		22,899	DistBill_RR-PF	12,078	4,227	6,593	-		
146	Total REVENUES		6,729,636		3,617,006	1,231,587	1,881,044	-		
147										
148	TOTAL EXPENSES		6,554,565		3,240,333	1,007,975	2,306,257	-		
149	**V. NET INCOME at Present Rates**		175,071		376,672	223,612	(425,213)	-		
150			175,071							
151	**SUMMARY REPORT**									
152	OPERATING REVENUES									
153	Utility Revenues	440-446	6,433,118		3,376,804	1,181,864	1,874,450	-		
154	Other Operating Revenues	450-456	296,518		240,202	49,723	6,593	-		
155	Total Operating Revenues		6,729,636		3,617,006	1,231,587	1,881,044	-		
156										
157	OPERATING EXPENSES									
158	Distribution / Transmission	580-599	1,602,629		1,231,124	325,612	45,893	-		
159	Customer Acctg & Service	901-919	1,093,791		0	0	1,093,791	-		
160	Admin & General	920-932	1,636,599		716,833	226,621	693,144	-		
161	Total Operating Expenses		4,333,019		1,947,957	552,233	1,832,829	-		
162										
163	Depreciation Expense	403	1,939,404		1,154,624	427,194	357,586	-		
164	Taxes Other Than Income	408	421,866		225,427	80,596	115,842	-		
165	INCOME BEFORE INCOME TAXES		35,348		288,998	171,564	(425,213)	-		
166	Income Taxes	409-411	(139,723)		(87,675)	(52,048)	0	-		
167	**NET INCOME**		175,071		376,672	223,612	(425,213)	-		
168										
169	**RATE BASE**		25,857,280		15,778,363	6,311,053	3,767,865	-		
170	Return on Rate Base		0.7%		2.4%	3.5%	(11.3%)			
171										

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Wellsboro Electric Company
Embedded Cost of Service Study (ECOSS)
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Funtionalization

Line	Account	No.	Balance	Allocator	Primary	Secondary	Billing		Labor Cost	Labor %
					4	5	6			
172	**REVENUE REQUIREMENTS**									
173	Target Rate of Return		8.1800%		8.1800%	8.1800%	8.1800%			
174										
175	Rate Base		25,857,280		15,778,363	6,311,053	3,767,865	-		
176								-		
177	Operating expenses		4,159,626		1,947,957	552,233	1,659,436	-		
178	Uncollectibles expense		20,000	BILL	0	0	20,000	-		
179	Depreciation expense		1,939,404		1,154,624	427,194	357,586	-		
180	Regulatory Commission Expenses		153,393	Plant	94,365	38,927	20,100	-		
181	General taxes / Other		44,148		27,159	11,204	5,785	-		
182	Subtotal- Operating Costs to recover		6,316,570		3,224,106	1,029,558	2,062,907	-		
183										
184	Target Return on Rate Base- After tax		2,115,125		1,290,670	516,244	308,211	-		
185										
186	Income taxes to recover		648,547	30.66%	395,750	158,293	94,505	-		
187				23.47%						
188	Subtotal- Rev Req before GRT		9,080,243		4,910,526	1,704,095	2,465,623	-		
189	GRT needed		548,782	6.27%	292,826	103,728	152,228	-		
190	**TOTAL REVENUE REQUIREMENT**		9,629,025		5,203,351	1,807,823	2,617,851	-		
191										
192	Revenue at Present rates		6,729,636		3,617,006	1,231,587	1,881,044	-		
193	Revenue Excess (Deficiency)		(2,899,388)		(1,586,346)	(576,235)	(736,807)	-		
194										

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Wellsboro Electric Company
Embedded Cost of Service Study (ECOSS)
FPFTY Ending December 31, 2026
Classification

Line	Account	No.	Secondary	Allocator	Demand	Customer
1	**I. ELECTRIC PLANT IN SERVICE**					
2	INTANGIBLE PLANT					
3	EDI Software	303	0	None	0	0
4	Total INTANGIBLE Plant		0		0	0
5						
6	**C. TRANSMISSION PLAN**					
7	Transmission Plant	361	0	None	0	0
8	Total TRANSMISSION Plant	350-359	0		0	0
9						
10	**D. DISTRIBUTION PLANT**					
11	Land & Land Rights	360	0	None	0	0
12	Structures and improvements	361	0	None	0	0
13	Station Equipment	362	0	None	0	0
14	Poles, Tower & Fixtures	364	2,482,988	PTF-Sec-Z	917,711	1,565,277
15	OH Conductors & Devices	365	1,131,481	OH-Sec-Z	497,461	634,020
16	UG Conduits and Conductors	366	442,880	UG-Sec-Z	282,151	160,729
17	Line Transformers	368	3,365,587	Trans-Min	755,617	2,609,971
18	Services	369	2,486,089	Customer	0	2,486,089
19	Meters	370	0	None	0	0
20	Install. Customers' premises	371	0	None	0	0
21	Street Lighting & Signal	373	125,272	Customer	0	125,272
22	Total DISTRIBUTION Plant	360-373	#########		2,452,940	7,581,357
23						
24	**E. GENERAL PLANT**					
25	General Plant	389	1,214,242	Sec-Lab	623,270	590,971
26	Communication Equip	398	14,640	Sec-Lab	7,515	7,125
27	Total GENERAL Plant	389-399	1,228,882		630,785	598,097
28						
29	**TOTAL UTILITY PLANT**		#########		3,083,725	8,179,454
30						

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Wellsboro Electric Company
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Classification

Line	Account	No.	Secondary	Allocator	Demand	Customer
31	**II. DEPRECIATION RESEI**					
32	Intangible Plant		0	None	0	0
33	Transmission Plant		0	None	0	0
34	Structures and improvements		0	None	0	0
35	Station Equipment		0	None	0	0
36	Poles, Towers and Fixtures		848,450	PTF-Sec-Z	313,587	534,863
37	OH Conductors and Devices		386,227	OH-Sec-Z	169,806	216,420
38	UG Conduits and Conductors		332,515	UG-Sec-Z	211,840	120,675
39	Line Transformers		1,697,284	Trans-Min	381,062	1,316,223
40	Services		1,472,321	Customer	0	1,472,321
41	Meters		0	None	0	0
42	Install. Customers' premises		0	None	0	0
43	Street Lighting & Signal		(63,042)	Customer	0	(63,042)
44	General Plant		363,675	Sec-GenPt	186,674	177,001
45	Total DEPRECIATION RESE	108	5,037,430		1,262,969	3,774,461
46						
47	**III. OTHER RATE BASE I**					
48	Cash Working Capital	131	65,985	Sec-OpExp	30,997	34,988
49	CWIP	131	0	Sec-Pt	0	0
50	Materials & Supplies	255	31,605	Sec-OpExp	14,847	16,758
51	Customer Deposits		0	None	0	0
52	ADIT	154	(9,828)	Sec-Pt	(2,691)	(7,137)
53	Accrued Pension / OPEB	182	(2,458)	Sec-Lab	(1,262)	(1,196)
54	Total OTHER RATE BASE	131-283	85,303		41,891	43,413
55						
56	**TOTAL RATE BASE**		6,311,053		1,862,647	4,448,406
57						

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Wellsboro Electric Company
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FPFTY Ending December 31, 2026
Classification

Line	Account	No.	Secondary	Allocator	Demand	Customer
58	**I. OPERATING AND MAIN**					
59	**B. TRANSMISSION EXPEI**					
60	Transmission Expense		0	None	0	0
61	Total TRANSMISSION Expe		0		0	0
62						
63	**C. DISTRIBUTION EXPEN**					
64	Ops Supv & Engineering	580	0	Sec-Lab	0	0
65	Station Expenses	582	0	None	0	0
66	OH Line Expenses	583	1,001	OH-Sec-Z	440	561
67	Street Lighting Expenses	585	267	Customer	0	267
68	Meter Expenses	586	0	None	0	0
69	Customer Install. expense	587	0	None	0	0
70	Misc. Distribution Expenses	588	81,120	Sec-OH_UG	56,453	24,667
71	Rents	589	10,271	Sec-Pt	2,812	7,459
72	Maint Supv & Engineering	590	19,585	Sec-Lab	10,053	9,532
73	Maint of Station Equip	592	0	None	0	0
74	Maint of OH Lines	593	163,834	OH-Sec-Z	72,030	91,803
75	Maint of UG Lines	594	17,193	UG-Sec-Z	10,953	6,240
76	Maint of Line Transformers	595	8,064	Trans-Min	1,810	6,253
77	Maint of Lighting	596	942	Customer	0	942
78	Maint of Misc. Plant	599	23,334	Sec-Pt	6,389	16,945
79	Total DISTR. O&M EXP.	500-599	325,612		160,940	164,671
80	Distribution Expense		325,612		160,940	164,671
81	**D. CUSTOMER ACCOUNTS AND S**					
82	Supervision	901	0	None	0	0
83	Meter Reading Exp	902	0	None	0	0
84	Customer Records & Coll	903	0	None	0	0
85	Uncollectible Accounts	904	0	None	0	0
86	Subtotal - Cust. Accts. Exp.	901-905	0		0	0
87						
88	Customer Assistance	908	0	None	0	0
89	OPEN	916	0	None	0	0
90	Subtotal - Cust. Svce. & Info.	908-916	0		0	0
91	Total CUST. ACCT. & SERV	901-919	0		0	0
92						

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Wellsboro Electric Company
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FPFTY Ending December 31, 2026
Classification

Line	Account	No.	Secondary [1]	Allocator	Demand [1]	Customer [3]
93	**E. ADMINISTRATIVE AND GENEF**					
94	Admin. & Gen'l. Salaries	920	113,150	Sec-Lab	58,080	55,070
95	Office Supplies & Expenses	921	13,623	Sec-Lab	6,993	6,630
96	Outside Services Employed	923	29,201	Sec-LabPt	11,492	17,709
97	Property Insurance	924	15,584	Sec-Pt	4,267	11,318
98	Employee Pensions & Benefits	926	0	Sec-Lab	0	0
99	Regulatory Comm. Expense	928	0	Sec-Pt	0	0
100	Misc. General Expense	930	20,897	Sec-LabPt	8,224	12,673
101	Rents	931	273	Sec-Lab	140	133
102	Maint General Property	932	33,892	Sec-Pt	9,279	24,613
103	Total A&G Expense	920-932	226,621		98,475	128,146
104						
105	TOTAL OPERATING EXPEI		552,233		259,415	292,817
106						
107	**II. DEPRECIATION EXPENSE**					
108	Intangible Plant		0	None	0	0
109	Station Equipment		0	None	0	0
110	Poles, Towers and Fixtures		84,745	PTF-Sec-Z	31,322	53,423
111	OH Conductors and Devices		43,737	OH-Sec-Z	19,229	24,508
112	UG Conduits and Conductors		19,171	UG-Sec-Z	12,213	6,957
113	Line Transformers		116,555	Trans-Min	26,168	90,387
114	Services		95,347	Customer	0	95,347
115	Meters		0	None	0	0
116	Install. Customers' premises		0	None	0	0
117	Street Lighting & Signal		2,971	Customer	0	2,971
118	General Plant		64,669	Sec-GenPt	33,195	31,474
119	Total DEPRECIATION Exp.	403	427,194		122,127	305,067
120						
121	**III. TAXES and OTHER**					
122	**A. GENERAL TAXES**					
123	Payroll related	408	0	None	0	0
124	PURTA, Real estate	408.16	10,991	Sec-Pt	3,009	7,982
125	Capital stock		0	Sec-RB	0	0
126	Other	408	212	Sec-Pt	58	154
127	Subtotal - General Taxes		11,204		3,067	8,136
128						
129	**B. GROSS RECEIPTS TAX**					
130	Gross Receipts tax		69,393	Sec-Rev	24,552	44,841
131	Subtotal- Gross Receipts tax		69,393		24,552	44,841
132						

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Wellsboro Electric Company
Embedded Cost of Service Study (ECOSS)
FPFTY Ending December 31, 2026
Classification

Line	Account	No.	Secondary [1]	Allocator	Demand [1]	Customer [2]
133	**B. FEDERAL / STATE INCOME TA**					
134	State Income Tax Expense		(32,048)	Sec-StaTax	(5,100)	(26,949)
135	Federal Income Tax Expense		(20,000)	Sec-FedTax	(3,182)	(16,818)
136	Subtotal - Fed / State Inc Tax	409-411	(52,048)		(8,282)	(43,766)
137	Total TAXES	408-411	28,548		19,337	9,211
138						
139	**TOTAL EXPENSES**		1,007,975		400,879	607,096
140						
141	**IV. OPERATING REVENUES at Pre**					
142	Distribution Revenue		1,181,864	Sec-RetRRPF	418,150	763,714
143	Forfeited Discounts		0	None	0	0
144	Rent For Electric Property		45,496	PTF-Sec-Z	16,815	28,680
145	Other Electric Revenues		4,227	Sec-RetRRPF	1,496	2,732
146	Total REVENUES		1,231,587		436,461	795,126
147						
148	TOTAL EXPENSES		1,007,975		400,879	607,096
149	**V. NET INCOME at Present Rates**		223,612		35,582	188,030
150						
151	**SUMMARY REPORT**					
152	OPERATING REVENUES					
153	Utility Revenues	440-446	1,181,864		418,150	763,714
154	Other Operating Revenues	450-456	49,723		18,311	31,412
155	Total Operating Revenues		1,231,587		436,461	795,126
156						
157	OPERATING EXPENSES					
158	Distribution / Transmission	580-599	325,612		160,940	164,671
159	Customer Acctg & Service	901-919	0		0	0
160	Admin & General	920-932	226,621		98,475	128,146
161	Total Operating Expenses		552,233		259,415	292,817
162						
163	Depreciation Expense	403	427,194		122,127	305,067
164	Taxes Other Than Income	408	80,596		27,619	52,977
165	INCOME BEFORE INCOME		171,564		27,300	144,264
166	Income Taxes	409-411	(52,048)		(8,282)	(43,766)
167	**NET INCOME**		223,612		35,582	188,030
168						
169	**RATE BASE**		6,311,053		1,862,647	4,448,406
170	Return on Rate Base					
171						

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Wellsboro Electric Company
Embedded Cost of Service Study (ECOSS)
FPFTY Ending December 31, 2026
Classification

Line	Account	No.	Secondary	Allocator	Demand	Customer
172	**REVENUE REQUIREMENTS**					
173	Target Rate of Return		8.1800%		8.1800%	8.1800%
174						
175	Rate Base		6,311,053		1,862,647	4,448,406
176						
177	Operating expenses		552,233		259,415	292,817
178	Uncollectibles expense		0	None	0	0
179	Depreciation expense		427,194		122,127	305,067
180	Regulatory Commission Expenses		38,927	Sec-Pt	10,658	28,270
181	General taxes / Other		11,204		3,067	8,136
182	Subtotal- Operating Costs to recover		1,029,558		395,267	634,291
183						
184	Target Return on Rate Base- After tax		516,244		152,365	363,880
185						
186	Income taxes to recover	30.66%	158,293		46,719	111,574
187						
188	Subtotal- Rev Req before GRT		1,704,095		594,351	1,109,744
189	GRT needed	6.27%	103,728		36,117	67,611
190	**TOTAL REVENUE REQUIREMEN**		1,807,823		630,468	1,177,355
191						
192	Revenue at Present rates					
193	Revenue Excess (Deficiency)					
194						

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Class Allocation- Primary Demand
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Wellsboro Electric Company
Embedded Cost of Service Study (ECOSS)
FPFTY Ending December 31, 2026
Class Allocation- Primary Demand

Line	Account	No.	Balance	Allocator	RS	RSAE	NRS	NRH	CS	CSH	IS	MSL	POL	EX
1	**I. ELECTRIC PLANT IN SERVICE**													
2	INTANGIBLE PLANT													
3	EDI Software	303	0	PriD-Lab	0	0	0	0	0	0	0	0	0	0
4	Total INTANGIBLE Plant		0		0	0	0	0	0	0	0	0	0	0
5														
6	**C. TRANSMISSION PLANT**													
7	Transmission Plant	361	0	None	0	0	0	0	0	0	0	0	0	0
8	Total TRANSMISSION Plant	350-359	0		0	0	0	0	0	0	0	0	0	0
9														
10	**D. DISTRIBUTION PLANT**													
11	Land & Land Rights	360	178,334	NCP-Prim	81,941	1,096	7,527	78	47,673	162	39,258	120	369	110
12	Structures and improvements	361	0	NCP-Prim	0	0	0	0	0	0	0	0	0	0
13	Station Equipment	362	3,992,800	NCP-Prim	1,834,608	24,545	168,528	1,753	1,067,372	3,629	878,966	2,682	8,255	2,462
14	Poles, Tower & Fixtures	364	12,450,184	NCP-Prim	5,720,598	76,535	525,497	5,466	3,328,236	11,317	2,740,757	8,362	25,740	7,677
15	OH Conductors & Devices	365	5,673,466	NCP-Prim	2,606,838	34,876	239,465	2,491	1,516,655	5,157	1,248,945	3,811	11,729	3,499
16	UG Conduits and Conductors	366	595,569	NCP-Prim	273,652	3,661	25,138	261	159,210	541	131,107	400	1,231	367
17	Line Transformers	368	0	None	0	0	0	0	0	0	0	0	0	0
18	Services	369	0	None	0	0	0	0	0	0	0	0	0	0
19	Meters	370	0	None	0	0	0	0	0	0	0	0	0	0
20	Install. Customers' premises	371	0	None	0	0	0	0	0	0	0	0	0	0
21	Street Lighting & Signal	373	0	None	0	0	0	0	0	0	0	0	0	0
22	Total DISTRIBUTION Plant	360-373	22,890,353		10,517,637	140,713	966,155	10,050	6,119,146	20,807	5,039,033	15,374	47,324	14,115
23														
24	**E. GENERAL PLANT**													
25	General Plant	389	4,360,516	PriD-Lab	2,003,566	26,805	184,048	1,914	1,165,672	3,964	959,915	2,929	9,015	2,689
26	Communication Equip	398	52,575	PriD-Lab	24,157	323	2,219	23	14,055	48	11,574	35	109	32
27	Total GENERAL Plant	389-399	4,413,091		2,027,723	27,128	186,268	1,938	1,179,726	4,011	971,488	2,964	9,124	2,721
28														
29	**TOTAL UTILITY PLANT**		27,303,444		12,545,359	167,841	1,152,422	11,987	7,298,872	24,818	6,010,522	18,338	56,447	16,837
30														

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Class Allocation- Primary Demand
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Wellsboro Electric Company
Embedded Cost of Service Study (ECOSS)
FPFTY Ending December 31, 2026
Class Allocation- Primary Demand

Line	Account	No.	Balance	Allocator	RS	RSAE	NRS	NRH	CS	CSH	IS	MSL	POL	EX
31	**II. DEPRECIATION RESERVE**													
32	Intangible Plant		0	None	0	0	0	0	0	0	0	0	0	0
33	Transmission Plant		0	None	0	0	0	0	0	0	0	0	0	0
34	Structures and improvements		0	NCP-Prim	0	0	0	0	0	0	0	0	0	0
35	Station Equipment		3,892,596	NCP-Prim	1,788,566	23,929	164,299	1,709	1,040,585	3,538	856,908	2,614	8,048	2,400
36	Poles, Towers and Fixtures		4,254,293	NCP-Prim	1,954,758	26,152	179,565	1,868	1,137,276	3,867	936,531	2,857	8,795	2,623
37	OH Conductors and Devices		1,936,617	NCP-Prim	889,835	11,905	81,741	850	517,705	1,760	426,323	1,301	4,004	1,194
38	UG Conduits and Conductors		447,154	NCP-Prim	205,458	2,749	18,873	196	119,535	406	98,436	300	924	276
39	Line Transformers		0	None	0	0	0	0	0	0	0	0	0	0
40	Services		0	None	0	0	0	0	0	0	0	0	0	0
41	Meters		0	None	0	0	0	0	0	0	0	0	0	0
42	Install. Customers' premises		0	None	0	0	0	0	0	0	0	0	0	0
43	Street Lighting & Signal		0	None	0	0	0	0	0	0	0	0	0	0
44	General Plant		1,306,009	PriD-Lab	600,084	8,028	55,124	573	349,128	1,187	287,502	877	2,700	805
45	Total DEPRECIATION RESE	108	11,836,669		5,438,701	72,763	499,602	5,197	3,164,228	10,759	2,605,699	7,950	24,471	7,299
46														
47	**III. OTHER RATE BASE ITEMS**													
48	Cash Working Capital	131	232,758	PriD-OpExp	106,947	1,431	9,824	102	62,222	212	51,239	156	481	144
49	CWIP	131	0	PriD-Pt	0	0	0	0	0	0	0	0	0	0
50	Materials & Supplies	255	111,484	PriD-Pt	51,224	685	4,705	49	29,802	101	24,542	75	230	69
51	Customer Deposits		0	None	0	0	0	0	0	0	0	0	0	0
52	ADIT	154	(23,825)	PriD-Pt	(10,947)	(146)	(1,006)	(10)	(6,369)	(22)	(5,245)	(16)	(49)	(15)
53	Accrued Pension / OPEB	182	(8,828)	PriD-Lab	(4,056)	(54)	(373)	(4)	(2,360)	(8)	(1,943)	(6)	(18)	(5)
54	Total OTHER RATE BASE	131-283	311,588		143,168	1,915	13,151	137	83,295	283	68,592	209	644	192
55														
56	**TOTAL RATE BASE**		15,778,363		7,249,826	96,994	665,972	6,927	4,217,938	14,342	3,473,415	10,597	32,620	9,730
57														

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Wellsboro Electric Company
Embedded Cost of Service Study (ECOSS)
FPFTY Ending December 31, 2026
Class Allocation- Primary Demand

Line	Account	No.	Balance	Allocator	RS	RSAE	NRS	NRH	CS	CSH	IS	MSL	POL	EX
58	**I. OPERATING AND MAINTENANCE EXPENSES**													
59	**B. TRANSMISSION EXPENSE**													
60	Transmission Expense		0	None	0	0	0	0	0	0	0	0	0	0
61	Total TRANSMISSION Expense		0		0	0	0	0	0	0	0	0	0	0
62														
63	**C. DISTRIBUTION EXPENSE**													
64	Ops Supv & Engineering	580	0	PriD-Lab	0	0	0	0	0	0	0	0	0	0
65	Station Expenses	582	0	NCP-Prim	0	0	0	0	0	0	0	0	0	0
66	OH Line Expenses	583	5,019	NCP-Prim	2,306	31	212	2	1,342	5	1,105	3	10	3
67	Street Lighting Expenses	585	0	None	0	0	0	0	0	0	0	0	0	0
68	Meter Expenses	586	0	None	0	0	0	0	0	0	0	0	0	0
69	Customer Install. expense	587	0	None	0	0	0	0	0	0	0	0	0	0
70	Misc. Distribution Expenses	588	204,569	NCP-Prim	93,995	1,258	8,634	90	54,686	186	45,033	137	423	126
71	Rents	589	23,431	NCP-Prim	10,766	144	989	10	6,264	21	5,158	16	48	14
72	Maint Supv & Engineering	590	81,705	PriD-Lab	37,542	502	3,449	36	21,842	74	17,986	55	169	50
73	Maint of Station Equip	592	18,557	NCP-Prim	8,527	114	783	8	4,961	17	4,085	12	38	11
74	Maint of OH Lines	593	821,493	NCP-Prim	377,459	5,050	34,674	361	219,605	747	180,842	552	1,698	507
75	Maint of UG Lines	594	23,120	NCP-Prim	10,623	142	976	10	6,181	21	5,090	16	48	14
76	Maint of Line Transformers	595	0	None	0	0	0	0	0	0	0	0	0	0
77	Maint of Lighting	596	0	None	0	0	0	0	0	0	0	0	0	0
78	Maint of Misc. Plant	599	53,230	NCP-Prim	24,458	327	2,247	23	14,230	48	11,718	36	110	33
79	Total DISTR. O&M EXP.	500-599	1,231,124		565,676	7,568	51,963	541	329,109	1,119	271,017	827	2,545	759
80	Distribution Expense		1,231,124		565,676	7,568	51,963	541	329,109	1,119	271,017	827	2,545	759
81	**D. CUSTOMER ACCOUNTS AND SERVICE**													
82	Supervision	901	0	None	0	0	0	0	0	0	0	0	0	0
83	Meter Reading Exp	902	0	None	0	0	0	0	0	0	0	0	0	0
84	Customer Records & Coll	903	0	None	0	0	0	0	0	0	0	0	0	0
85	Uncollectible Accounts	904	0	None	0	0	0	0	0	0	0	0	0	0
86	Subtotal - Cust. Accts. Exp.	901-905	0		0	0	0	0	0	0	0	0	0	0
87														
88	Customer Assistance	908	0	None	0	0	0	0	0	0	0	0	0	0
89	OPEN	916	0	None	0	0	0	0	0	0	0	0	0	0
90	Subtotal - Cust. Svce. & Info.	908-916	0		0	0	0	0	0	0	0	0	0	0
91	Total CUST. ACCT. & SERV	901-919	0		0	0	0	0	0	0	0	0	0	0
92														

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Line	Account	No.	Balance	Allocator	RS	RSAE	NRS	NRH	CS	CSH	IS	MSL	POL	EX
93	**E. ADMINISTRATIVE AND GENERAL**													
94	Admin. & Gen'l. Salaries	920	406,339	PriD-Lab	186,704	2,498	17,151	178	108,624	369	89,451	273	840	251
95	Office Supplies & Expenses	921	48,922	PriD-Lab	22,479	301	2,065	21	13,078	44	10,770	33	101	30
96	Outside Services Employed	923	81,984	PriD-LabPt	37,670	504	3,460	36	21,916	75	18,048	55	169	51
97	Property Insurance	924	37,779	PriD-Pt	17,359	232	1,595	17	10,099	34	8,317	25	78	23
98	Employee Pensions & Benefits	926	0	PriD-Lab	0	0	0	0	0	0	0	0	0	0
99	Regulatory Comm. Expense	928	0	PriD-Pt	0	0	0	0	0	0	0	0	0	0
100	Misc. General Expense	930	58,669	PriD-LabPt	26,957	361	2,476	26	15,684	53	12,915	39	121	36
101	Rents	931	981	PriD-Lab	451	6	41	0	262	1	216	1	2	1
102	Maint General Property	932	82,159	PriD-Pt	37,750	505	3,468	36	21,963	75	18,086	55	170	51
103	Total A&G Expense	920-932	716,833		329,370	4,407	30,256	315	191,627	652	157,802	481	1,482	442
104														
105	TOTAL OPERATING EXPENSES		1,947,957		895,045	11,975	82,219	855	520,736	1,771	428,819	1,308	4,027	1,201
106														
107	**II. DEPRECIATION EXPENSE**													
108	Intangible Plant		0	None	0	0	0	0	0	0	0	0	0	0
109	Station Equipment		252,375	NCP-Prim	115,961	1,551	10,652	111	67,466	229	55,557	170	522	156
110	Poles, Towers and Fixtures		424,929	NCP-Prim	195,246	2,612	17,935	187	113,594	386	93,543	285	879	262
111	OH Conductors and Devices		219,304	NCP-Prim	100,766	1,348	9,256	96	58,625	199	48,277	147	453	135
112	UG Conduits and Conductors		25,780	NCP-Prim	11,845	158	1,088	11	6,892	23	5,675	17	53	16
113	Line Transformers		0	None	0	0	0	0	0	0	0	0	0	0
114	Services		0	None	0	0	0	0	0	0	0	0	0	0
115	Meters		0	None	0	0	0	0	0	0	0	0	0	0
116	Install. Customers' premises		0	None	0	0	0	0	0	0	0	0	0	0
117	Street Lighting & Signal		0	None	0	0	0	0	0	0	0	0	0	0
118	General Plant		232,236	PriD-Lab	106,707	1,428	9,802	102	62,082	211	51,124	156	480	143
119	Total DEPRECIATION Exp.	403	1,154,624		530,526	7,098	48,734	507	308,659	1,050	254,176	775	2,387	712
120														
121	**III. TAXES and OTHER**													
122	**A. GENERAL TAXES**													
123	Payroll related	408	0	None	0	0	0	0	0	0	0	0	0	0
124	PURTA, Real estate	408.16	26,644	PriD-Pt	12,243	164	1,125	12	7,123	24	5,865	18	55	16
125	Capital stock		0	RateBase	0	0	0	0	0	0	0	0	0	0
126	Other	408	515	PriD-Pt	237	3	22	0	138	0	113	0	1	0
127	Subtotal - General Taxes		27,159		12,479	167	1,146	12	7,260	25	5,979	18	56	17
128														
129	**B. GROSS RECEIPTS TAX**													
130	Gross Receipts tax		198,268	Dist_Rev	104,391	762	15,443	21	47,151	32	27,254	418	2,520	277
131	Subtotal- Gross Receipts tax		198,268		104,391	762	15,443	21	47,151	32	27,254	418	2,520	277
132														

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Line	Account	No.	Balance	Allocator	RS	RSAE	NRS	NRH	CS	CSH	IS	MSL	POL	EX
133	**B. FEDERAL / STATE INCOME TAXES**													
134	State Income Tax Expense		(53,985)	PreStaTax	(29,833)	(299)	(3,912)	(20)	(12,168)	(40)	(7,379)	(110)	(168)	(55)
135	Federal Income Tax Expense		(33,690)	PreFedTax	(18,618)	(186)	(2,441)	(12)	(7,594)	(25)	(4,605)	(69)	(105)	(34)
136	Subtotal - Fed / State Inc Tax	409-411	(87,675)		(48,451)	(485)	(6,353)	(32)	(19,762)	(66)	(11,984)	(179)	(274)	(90)
137	Total TAXES	408-411	137,752		68,419	444	10,236	1	34,649	(9)	21,249	257	2,303	205
138														
139	**TOTAL EXPENSES**		3,240,333		1,493,990	19,516	141,189	1,363	864,044	2,811	704,244	2,341	8,717	2,118
140														
141	**IV. OPERATING REVENUES at Present Rates**													
142	Distribution Revenue		3,376,804	Dist_Rev	1,777,935	12,973	263,012	357	803,047	542	464,176	7,119	42,920	4,724
143	Forfeited Discounts		0	None	0	0	0	0	0	0	0	0	0	0
144	Rent For Electric Property		228,123	NCP-Prim	104,818	1,402	9,629	100	60,983	207	50,219	153	472	141
145	Other Electric Revenues		12,078	Dist_Rev	6,359	46	941	1	2,872	2	1,660	25	154	17
146	Total REVENUES		3,617,006		1,889,112	14,421	273,581	458	866,902	752	516,055	7,297	43,545	4,882
147														
148	TOTAL EXPENSES		3,240,333		1,493,990	19,516	141,189	1,363	864,044	2,811	704,244	2,341	8,717	2,118
149	**V. NET INCOME at Present Rates**		376,672		395,123	(5,095)	132,392	(905)	2,858	(2,059)	(188,189)	4,957	34,828	2,764
150														
151	**SUMMARY REPORT**													
152	OPERATING REVENUES													
153	Utility Revenues	440-446	3,376,804		1,777,935	12,973	263,012	357	803,047	542	464,176	7,119	42,920	4,724
154	Other Operating Revenues	450-456	240,202		111,177	1,449	10,569	101	63,855	209	51,879	179	625	158
155	Total Operating Revenues		3,617,006		1,889,112	14,421	273,581	458	866,902	752	516,055	7,297	43,545	4,882
156														
157	OPERATING EXPENSES													
158	Distribution / Transmission	580-599	1,231,124		565,676	7,568	51,963	541	329,109	1,119	271,017	827	2,545	759
159	Customer Acctg & Service	901-919	0		0	0	0	0	0	0	0	0	0	0
160	Admin & General	920-932	716,833		329,370	4,407	30,256	315	191,627	652	157,802	481	1,482	442
161	Total Operating Expenses		1,947,957		895,045	11,975	82,219	855	520,736	1,771	428,819	1,308	4,027	1,201
162														
163	Depreciation Expense	403	1,154,624		530,526	7,098	48,734	507	308,659	1,050	254,176	775	2,387	712
164	Taxes Other Than Income	408	225,427		116,870	929	16,589	33	54,411	57	33,233	436	2,576	294
165	INCOME BEFORE INCOME		288,998		346,671	(5,580)	126,038	(937)	(16,904)	(2,125)	(200,173)	4,777	34,555	2,674
166	Income Taxes	409-411	(87,675)		(48,451)	(485)	(6,353)	(32)	(19,762)	(66)	(11,984)	(179)	(274)	(90)
167	**NET INCOME**		376,672		395,123	(5,095)	132,392	(905)	2,858	(2,059)	(188,189)	4,957	34,828	2,764
168														
169	**RATE BASE**		15,778,363		7,249,826	96,994	665,972	6,927	4,217,938	14,342	3,473,415	10,597	32,620	9,730
170	Return on Rate Base		2.39%											
171														

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Line	Account	No.	Balance	Allocator	RS	RSAE	NRS	NRH	CS	CSH	IS	MSL	POL	EX
172	**REVENUE REQUIREMENTS**													
173	Target Rate of Return		8.1800%		8.1800%	8.1800%	8.1800%	8.1800%	8.1800%	8.1800%	8.1800%	8.1800%	8.1800%	8.1800%
174														
175	Rate Base		15,778,363		7,249,826	96,994	665,972	6,927	4,217,938	14,342	3,473,415	10,597	32,620	9,730
176														
177	Operating expenses		1,947,957		895,045	11,975	82,219	855	520,736	1,771	428,819	1,308	4,027	1,201
178	Uncollectibles expense		0	None	0	0	0	0	0	0	0	0	0	0
179	Depreciation expense		1,154,624		530,526	7,098	48,734	507	308,659	1,050	254,176	775	2,387	712
180	Regulatory Commission Expenses		94,365	PriD-Pt	43,359	580	3,983	41	25,226	86	20,773	63	195	58
181	General taxes / Other		27,159		12,479	167	1,146	12	7,260	25	5,979	18	56	17
182	Subtotal- Operating Costs to recover		3,224,106		1,481,409	19,819	136,083	1,416	861,882	2,931	709,748	2,165	6,666	1,988
183														
184	Target Return on Rate Base- After tax		1,290,670		593,036	7,934	54,477	567	345,027	1,173	284,125	867	2,668	796
185														
186	Income taxes to recover		395,750	30.66%	181,839	2,433	16,704	174	105,793	360	87,119	266	818	244
187														
188	Subtotal- Rev Req before GRT		4,910,526		2,256,283	30,186	207,263	2,156	1,312,702	4,464	1,080,993	3,298	10,152	3,028
189	GRT needed		292,826	6.27%	134,497	1,802	12,333	129	78,302	267	64,525	196	597	180
190	**TOTAL REVENUE REQUIREMEN**		5,203,351		2,390,780	31,988	219,596	2,285	1,391,004	4,730	1,145,517	3,494	10,749	3,208
191														
192	Revenue at Present rates		3,617,006		1,889,112	14,421	273,581	458	866,902	752	516,055	7,297	43,545	4,882
193	Revenue Excess (Deficiency)		(1,586,346)		(501,668)	(17,567)	53,985	(1,827)	(524,102)	(3,979)	(629,462)	3,804	32,796	1,674
194														

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Wellsboro Electric Company
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FPFTY Ending December 31, 2026
Class Allocation- Secondary Demand

Line	Account	No.	Balance	Allocator	RS	RSAE	NRS	NRH	CS	CSH	IS	MSL	POL	EX
1	**I. ELECTRIC PLANT IN SERVICE**													
2	INTANGIBLE PLANT													
3	EDI Software	303	0	SecD-Lab	0	0	0	0	0	0	0	0	0	0
4	Total INTANGIBLE Plant		0		0	0	0	0	0	0	0	0	0	0
5														
6	**C. TRANSMISSION PLANT**													
7	Transmission Plant	361	0	None	0	0	0	0	0	0	0	0	0	0
8	Total TRANSMISSION Plant	350-359	0		0	0	0	0	0	0	0	0	0	0
9														
10	**D. DISTRIBUTION PLANT**													
11	Land & Land Rights	360	0	None	0	0	0	0	0	0	0	0	0	0
12	Structures and improvements	361	0	None	0	0	0	0	0	0	0	0	0	0
13	Station Equipment	362	0	None	0	0	0	0	0	0	0	0	0	0
14	Poles, Tower & Fixtures	364	917,711	NCP-Sec	541,125	7,240	49,708	517	314,826	1,070	0	791	2,435	0
15	OH Conductors & Devices	365	497,461	NCP-Sec	293,326	3,924	26,945	280	170,657	580	0	429	1,320	0
16	UG Conduits and Conductors	366	282,151	NCP-Sec	166,369	2,226	15,283	159	96,793	329	0	243	749	0
17	Line Transformers	368	755,617	NCP-Ltr	0	0	0	893	740,661	2,821	0	2,756	8,485	0
18	Services	369	0	None	0	0	0	0	0	0	0	0	0	0
19	Meters	370	0	None	0	0	0	0	0	0	0	0	0	0
20	Install. Customers' premises	371	0	None	0	0	0	0	0	0	0	0	0	0
21	Street Lighting & Signal	373	0	None	0	0	0	0	0	0	0	0	0	0
22	Total DISTRIBUTION Plant	360-373	2,452,940		1,000,820	13,390	91,936	1,849	1,322,937	4,801	0	4,219	12,988	0
23														
24	**E. GENERAL PLANT**													
25	General Plant	389	623,270	SecD-Lab	362,255	4,847	33,277	357	219,493	750	0	562	1,730	0
26	Communication Equip	398	7,515	SecD-Lab	4,368	58	401	4	2,646	9	0	7	21	0
27	Total GENERAL Plant	389-399	630,785		366,623	4,905	33,678	361	222,140	759	0	569	1,751	0
28														
29	**TOTAL UTILITY PLANT**		3,083,725		1,367,443	18,295	125,614	2,210	1,545,077	5,560	0	4,788	14,739	0
30														

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Line	Account	No.	Balance	Allocator	RS	RSAE	NRS	NRH	CS	CSH	IS	MSL	POL	EX
31	**II. DEPRECIATION RESERVE**													
32	Intangible Plant		0	None	0	0	0	0	0	0	0	0	0	0
33	Transmission Plant		0	None	0	0	0	0	0	0	0	0	0	0
34	Structures and improvements		0	None	0	0	0	0	0	0	0	0	0	0
35	Station Equipment		0	None	0	0	0	0	0	0	0	0	0	0
36	Poles, Towers and Fixtures		313,587	NCP-Sec	184,905	2,474	16,985	177	107,578	366	0	270	832	0
37	OH Conductors and Devices		169,806	NCP-Sec	100,126	1,340	9,198	96	58,253	198	0	146	451	0
38	UG Conduits and Conductors		211,840	NCP-Sec	124,910	1,671	11,474	119	72,673	247	0	183	562	0
39	Line Transformers		381,062	NCP-Ltr	0	0	0	450	373,520	1,423	0	1,390	4,279	0
40	Services		0	None	0	0	0	0	0	0	0	0	0	0
41	Meters		0	None	0	0	0	0	0	0	0	0	0	0
42	Install. Customers' premises		0	None	0	0	0	0	0	0	0	0	0	0
43	Street Lighting & Signal		0	None	0	0	0	0	0	0	0	0	0	0
44	General Plant		186,674	SecD-Lab	108,498	1,452	9,967	107	65,740	225	0	168	518	0
45	Total DEPRECIATION RESE	108	1,262,969		518,439	6,936	47,624	949	677,763	2,458	0	2,158	6,642	0
46														
47	**III. OTHER RATE BASE I**													
48	Cash Working Capital	131	30,997	SecD-OpExp	17,655	236	1,622	18	11,306	39	0	30	91	0
49	CWIP	131	0	SecD-Pt	0	0	0	0	0	0	0	0	0	0
50	Materials & Supplies	255	14,847	SecD-Pt	6,584	88	605	11	7,439	27	0	23	71	0
51	Customer Deposits		0	None	0	0	0	0	0	0	0	0	0	0
52	ADIT	154	(2,691)	SecD-Pt	(1,193)	(16)	(110)	(2)	(1,348)	(5)	0	(4)	(13)	0
53	Accrued Pension / OPEB	182	(1,262)	SecD-Lab	(733)	(10)	(67)	(1)	(444)	(2)	0	(1)	(4)	0
54	Total OTHER RATE BASE	131-283	41,891		22,312	299	2,050	26	16,952	59	0	47	146	0
55														
56	**TOTAL RATE BASE**		1,862,647		871,315	11,657	80,039	1,287	884,266	3,161	0	2,678	8,243	0
57														

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Wellsboro Electric Company
Embedded Cost of Service Study (ECOSS)
FPFTY Ending December 31, 2026
Class Allocation- Secondary Demand

Line	Account	No.	Balance	Allocator	RS	RSAE	NRS	NRH	CS	CSH	IS	MSL	POL	EX
58	**I. OPERATING AND MAINTENANCE EXPENSES**													
59	**B. TRANSMISSION EXPENSE**													
60	Transmission Expense		0	None	0	0	0	0	0	0	0	0	0	0
61	Total TRANSMISSION Expe		0		0	0	0	0	0	0	0	0	0	0
62														
63	**C. DISTRIBUTION EXPENSE**													
64	Ops Supv & Engineering	580	0	SecD-Lab	0	0	0	0	0	0	0	0	0	0
65	Station Expenses	582	0	None	0	0	0	0	0	0	0	0	0	0
66	OH Line Expenses	583	440	NCP-Sec	259	3	24	0	151	1	0	0	1	0
67	Street Lighting Expenses	585	0	None	0	0	0	0	0	0	0	0	0	0
68	Meter Expenses	586	0	None	0	0	0	0	0	0	0	0	0	0
69	Customer Install. expense	587	0	None	0	0	0	0	0	0	0	0	0	0
70	Misc. Distribution Expenses	588	56,453	NCP-Sec	33,287	445	3,058	32	19,366	66	0	49	150	0
71	Rents	589	2,812	NCP-Sec	1,658	22	152	2	965	3	0	2	7	0
72	Maint Supv & Engineering	590	10,053	SecD-Lab	5,843	78	537	6	3,540	12	0	9	28	0
73	Maint of Station Equip	592	0	None	0	0	0	0	0	0	0	0	0	0
74	Maint of OH Lines	593	72,030	NCP-Sec	42,472	568	3,902	41	24,710	84	0	62	191	0
75	Maint of UG Lines	594	10,953	NCP-Sec	6,459	86	593	6	3,758	13	0	9	29	0
76	Maint of Line Transformers	595	1,810	NCP-Ltr	0	0	0	2	1,775	7	0	7	20	0
77	Maint of Lighting	596	0	None	0	0	0	0	0	0	0	0	0	0
78	Maint of Misc. Plant	599	6,389	NCP-Sec	3,767	50	346	4	2,192	7	0	6	17	0
79	Total DISTR. O&M EXP.	500-599	160,940		93,746	1,254	8,612	92	56,457	193	0	144	444	0
80	Distribution Expense		160,940		93,746	1,254	8,612	92	56,457	193	0	144	444	0
81	**D. CUSTOMER ACCOUNTS AND SERVICE**													
82	Supervision	901	0	None	0	0	0	0	0	0	0	0	0	0
83	Meter Reading Exp	902	0	None	0	0	0	0	0	0	0	0	0	0
84	Customer Records & Coll	903	0	None	0	0	0	0	0	0	0	0	0	0
85	Uncollectible Accounts	904	0	None	0	0	0	0	0	0	0	0	0	0
86	Subtotal - Cust. Accts. Exp.	901-905	0		0	0	0	0	0	0	0	0	0	0
87														
88	Customer Assistance	908	0	None	0	0	0	0	0	0	0	0	0	0
89	OPEN	916	0	None	0	0	0	0	0	0	0	0	0	0
90	Subtotal - Cust. Svce. & Info.	908-916	0		0	0	0	0	0	0	0	0	0	0
91	Total CUST. ACCT. & SERV	901-919	0		0	0	0	0	0	0	0	0	0	0
92														

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Wellsboro Electric Company
Embedded Cost of Service Study (ECOSS)
FPFTY Ending December 31, 2026
Class Allocation- Secondary Demand

Line	Account	No.	Balance	Allocator	RS	RSAE	NRS	NRH	CS	CSH	IS	MSL	POL	EX
93	**E. ADMINISTRATIVE AND GENERAL**													
94	Admin. & Gen'l. Salaries	920	58,080	SecD-Lab	33,757	452	3,101	33	20,454	70	0	52	161	0
95	Office Supplies & Expenses	921	6,993	SecD-Lab	4,064	54	373	4	2,463	8	0	6	19	0
96	Outside Services Employed	923	11,492	SecD-LabPt	5,888	79	541	7	4,903	17	0	14	43	0
97	Property Insurance	924	4,267	SecD-Pt	1,892	25	174	3	2,138	8	0	7	20	0
98	Employee Pensions & Benefits	926	0	SecD-Lab	0	0	0	0	0	0	0	0	0	0
99	Regulatory Comm. Expense	928	0	SecD-Pt	0	0	0	0	0	0	0	0	0	0
100	Misc. General Expense	930	8,224	SecD-LabPt	4,213	56	387	5	3,508	12	0	10	31	0
101	Rents	931	140	SecD-Lab	82	1	7	0	49	0	0	0	0	0
102	Maint General Property	932	9,279	SecD-Pt	4,115	55	378	7	4,649	17	0	14	44	0
103	Total A&G Expense	920-932	98,475		54,011	723	4,961	60	38,164	133	0	104	320	0
104														
105	TOTAL OPERATING EXPENSES		259,415		147,756	1,977	13,573	152	94,620	325	0	248	764	0
106														
107	**II. DEPRECIATION EXPENSE**													
108	Intangible Plant		0	None	0	0	0	0	0	0	0	0	0	0
109	Station Equipment		0	None	0	0	0	0	0	0	0	0	0	0
110	Poles, Towers and Fixtures		31,322	NCP-Sec	18,469	247	1,697	18	10,745	37	0	27	83	0
111	OH Conductors and Devices		19,229	NCP-Sec	11,338	152	1,042	11	6,597	22	0	17	51	0
112	UG Conduits and Conductors		12,213	NCP-Sec	7,202	96	662	7	4,190	14	0	11	32	0
113	Line Transformers		26,168	NCP-Ltr	0	0	0	31	25,650	98	0	95	294	0
114	Services		0	None	0	0	0	0	0	0	0	0	0	0
115	Meters		0	None	0	0	0	0	0	0	0	0	0	0
116	Install. Customers' premises		0	None	0	0	0	0	0	0	0	0	0	0
117	Street Lighting & Signal		0	None	0	0	0	0	0	0	0	0	0	0
118	General Plant		33,195	SecD-Lab	19,293	258	1,772	19	11,690	40	0	30	92	0
119	Total DEPRECIATION Exp.	403	122,127		56,302	753	5,172	85	58,872	211	0	179	553	0
120														
121	**III. TAXES and OTHER**													
122	**A. GENERAL TAXES**													
123	Payroll related	408	0	SecD-Lab	0	0	0	0	0	0	0	0	0	0
124	PURTA, Real estate	408.16	3,009	SecD-Pt	1,334	18	123	2	1,508	5	0	5	14	0
125	Capital stock		0	RateBase	0	0	0	0	0	0	0	0	0	0
126	Other	408	58	SecD-Pt	26	0	2	0	29	0	0	0	0	0
127	Subtotal - General Taxes		3,067		1,360	18	125	2	1,537	6	0	5	15	0
128														
129	**B. GROSS RECEIPTS TAX**													
130	Gross Receipts tax		24,552	Dist_Rev	12,927	94	1,912	3	5,839	4	3,375	52	312	34
131	Subtotal- Gross Receipts tax		24,552		12,927	94	1,912	3	5,839	4	3,375	52	312	34
132														

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Wellsboro Electric Company
Embedded Cost of Service Study (ECOSS)
FPFTY Ending December 31, 2026
Class Allocation- Secondary Demand

Line	Account	No.	Balance	Allocator	RS	RSAE	NRS	NRH	CS	CSH	IS	MSL	POL	EX
133	**B. FEDERAL / STATE INCOME TAXES**													
134	State Income Tax Expense		(5,100)	PreStaTax	(2,818)	(28)	(370)	(2)	(1,149)	(4)	(697)	(10)	(16)	(5)
135	Federal Income Tax Expense		(3,182)	PreFedTax	(1,759)	(18)	(231)	(1)	(717)	(2)	(435)	(7)	(10)	(3)
136	Subtotal - Fed / State Inc Tax	409-411	(8,282)		(4,577)	(46)	(600)	(3)	(1,867)	(6)	(1,132)	(17)	(26)	(8)
137	Total TAXES	408-411	19,337		9,710	67	1,437	2	5,509	3	2,243	40	301	26
138														
139	**TOTAL EXPENSES**		400,879		213,768	2,797	20,182	239	159,001	539	2,243	467	1,617	26
140														
141	**IV. OPERATING REVENUES at Present Rates**													
142	Distribution Revenue		418,150	Dist_Rev	220,162	1,606	32,569	44	99,441	67	57,479	882	5,315	585
143	Forfeited Discounts		0	None	0	0	0	0	0	0	0	0	0	0
144	Rent For Electric Property		16,815	NCP-Sec	9,915	133	911	9	5,769	20	0	14	45	0
145	Other Electric Revenues		1,496	Dist_Rev	787	6	116	0	356	0	206	3	19	2
146	Total REVENUES		436,461		230,864	1,745	33,596	54	105,566	87	57,685	899	5,378	587
147														
148	TOTAL EXPENSES		400,879		213,768	2,797	20,182	239	159,001	539	2,243	467	1,617	26
149	**V. NET INCOME at Present Rates**		35,582		17,096	(1,052)	13,414	(185)	(53,435)	(452)	55,442	432	3,761	561
150														
151	**SUMMARY REPORT**													
152	OPERATING REVENUES													
153	Utility Revenues	440-446	418,150		220,162	1,606	32,569	44	99,441	67	57,479	882	5,315	585
154	Other Operating Revenues	450-456	18,311		10,702	138	1,027	10	6,124	20	206	18	64	2
155	Total Operating Revenues		436,461		230,864	1,745	33,596	54	105,566	87	57,685	899	5,378	587
156														
157	OPERATING EXPENSES													
158	Distribution / Transmission	580-599	160,940		93,746	1,254	8,612	92	56,457	193	0	144	444	0
159	Customer Acctg & Service	901-919	0		0	0	0	0	0	0	0	0	0	0
160	Admin & General	920-932	98,475		54,011	723	4,961	60	38,164	133	0	104	320	0
161	Total Operating Expenses		259,415		147,756	1,977	13,573	152	94,620	325	0	248	764	0
162														
163	Depreciation Expense	403	122,127		56,302	753	5,172	85	58,872	211	0	179	553	0
164	Taxes Other Than Income	408	27,619		14,287	113	2,037	5	7,376	9	3,375	57	327	34
165	INCOME BEFORE INCOME		27,300		12,519	(1,098)	12,814	(188)	(55,302)	(459)	54,310	415	3,735	553
166	Income Taxes	409-411	(8,282)		(4,577)	(46)	(600)	(3)	(1,867)	(6)	(1,132)	(17)	(26)	(8)
167	**NET INCOME**		35,582		17,096	(1,052)	13,414	(185)	(53,435)	(452)	55,442	432	3,761	561
168														
169	**RATE BASE**		1,862,647		871,315	11,657	80,039	1,287	884,266	3,161	0	2,678	8,243	0
170	Return on Rate Base		1.91%											
171														

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Wellsboro Electric Company
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FPFTY Ending December 31, 2026
Class Allocation- Secondary Demand

Line	Account	No.	Balance	Allocator	RS	RSAE	NRS	NRH	CS	CSH	IS	MSL	POL	EX
172	**REVENUE REQUIREMENTS**													
173	Target Rate of Return		8.1800%		8.1800%	8.1800%	8.1800%	8.1800%	8.1800%	8.1800%	8.1800%	8.1800%	8.1800%	8.1800%
174														
175	Rate Base		1,862,647		871,315	11,657	80,039	1,287	884,266	3,161	0	2,678	8,243	0
176														
177	Operating expenses		259,415		147,756	1,977	13,573	152	94,620	325	0	248	764	0
178	Uncollectibles expense		0	None	0	0	0	0	0	0	0	0	0	0
179	Depreciation expense		122,127		56,302	753	5,172	85	58,872	211	0	179	553	0
180	Regulatory Commission Expenses		10,658	SecD-Pt	4,726	63	434	8	5,340	19	0	17	51	0
181	General taxes / Other		3,067		1,360	18	125	2	1,537	6	0	5	15	0
182	Subtotal- Operating Costs to recover		395,267		210,145	2,811	19,304	247	160,369	561	0	449	1,382	0
183														
184	Target Return on Rate Base- After tax		152,365		71,274	954	6,547	105	72,333	259	0	219	674	0
185														
186	Income taxes to recover		46,719	30.66%	21,854	292	2,008	32	22,179	79	0	67	207	0
187														
188	Subtotal- Rev Req before GRT		594,351		303,272	4,057	27,859	384	254,881	899	0	735	2,263	0
189	GRT needed		36,117	6.27%	18,344	246	1,682	23	15,597	55	(13)	45	138	(0)
190	**TOTAL REVENUE REQUIREMEN**		630,468		321,616	4,303	29,541	408	270,478	954	(13)	780	2,401	(0)
191														
192	Revenue at Present rates		436,461		230,864	1,745	33,596	54	105,566	87	57,685	899	5,378	587
193	Revenue Excess (Deficiency)		(194,007)		(90,752)	(2,558)	4,055	(354)	(164,912)	(867)	57,698	119	2,977	587
194														

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Wellsboro Electric Company
Embedded Cost of Service Study (ECOSS)
FPFTY Ending December 31, 2026
Class Allocation- Secondary Customer

Line	Account	No.	Balance	Allocator	RS	RSAE	NRS	NRH	CS	CSH	IS	MSL	POL	EX
1	**I. ELECTRIC PLANT IN SERVICE**													
2	INTANGIBLE PLANT													
3	EDI Software	303	0	None	0	0	0	0	0	0	0	0	0	0
4	Total INTANGIBLE Plant		0		0	0	0	0	0	0	0	0	0	0
5														
6	**C. TRANSMISSION PLANT**													
7	Transmission Plant	361	0	None	0	0	0	0	0	0	0	0	0	0
8	Total TRANSMISSION Plant	350-359	0		0	0	0	0	0	0	0	0	0	0
9														
10	**D. DISTRIBUTION PLANT**													
11	Land & Land Rights	360	0	None	0	0	0	0	0	0	0	0	0	0
12	Structures and improvements	361	0	None	0	0	0	0	0	0	0	0	0	0
13	Station Equipment	362	0	None	0	0	0	0	0	0	0	0	0	0
14	Poles, Tower & Fixtures	364	1,565,277	Avg-Cust-Sec	1,237,723	6,997	225,073	240	94,044	240	0	0	0	960
15	OH Conductors & Devices	365	634,020	Avg-Cust-Sec	501,343	2,834	91,167	97	38,093	97	0	0	0	389
16	UG Conduits and Conductors	366	160,729	Avg-Cust-Sec	127,094	719	23,111	25	9,657	25	0	0	0	99
17	Line Transformers	368	2,609,971	Avg-Cust-Sec	2,063,802	11,667	375,291	400	156,810	400	0	0	0	1,600
18	Services	369	2,486,089	Services_Cost	1,838,344	10,393	334,293	356	292,025	745	9,933	0	0	0
19	Meters	370	0	None	0	0	0	0	0	0	0	0	0	0
20	Install. Customers' premises	371	0	None	0	0	0	0	0	0	0	0	0	0
21	Street Lighting & Signal	373	125,272	StLgt-Lamps	0	0	0	0	0	0	0	62,636	62,636	0
22	Total DISTRIBUTION Plant	360-373	7,581,357		5,768,306	32,610	1,048,935	1,118	590,629	1,507	9,933	62,636	62,636	3,047
23														
24	**E. GENERAL PLANT**													
25	General Plant	389	590,971	SecC-Lab	457,263	2,585	83,151	89	36,396	93	108	5,474	5,474	339
26	Communication Equip	398	7,125	SecC-Lab	5,513	31	1,003	1	439	1	1	66	66	4
27	Total GENERAL Plant	389-399	598,097		462,776	2,616	84,153	90	36,835	94	109	5,540	5,540	343
28														
29	**TOTAL UTILITY PLANT**		8,179,454		6,231,082	35,227	1,133,089	1,208	627,464	1,601	10,042	68,176	68,176	3,390
30														

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Class Allocation- Secondary Customer

Line	Account	No.	Balance	Allocator	RS	RSAE	NRS	NRH	CS	CSH	IS	MSL	POL	EX
31	**II. DEPRECIATION RESERVE**													
32	Intangible Plant		0	None	0	0	0	0	0	0	0	0	0	0
33	Transmission Plant		0	None	0	0	0	0	0	0	0	0	0	0
34	Structures and improvements		0	None	0	0	0	0	0	0	0	0	0	0
35	Station Equipment		0	None	0	0	0	0	0	0	0	0	0	0
36	Poles, Towers and Fixtures		534,863	Avg-Cust-Sec	422,936	2,391	76,909	82	32,135	82	0	0	0	328
37	OH Conductors and Devices		216,420	Avg-Cust-Sec	171,132	967	31,119	33	13,003	33	0	0	0	133
38	UG Conduits and Conductors		120,675	Avg-Cust-Sec	95,422	539	17,352	18	7,250	18	0	0	0	74
39	Line Transformers		1,316,223	Avg-Cust-Sec	1,040,787	5,884	189,261	202	79,080	202	0	0	0	807
40	Services		1,472,321	Services_Cost	1,088,711	6,155	197,976	211	172,944	441	5,882	0	0	0
41	Meters		0	None	0	0	0	0	0	0	0	0	0	0
42	Install. Customers' premises		0	None	0	0	0	0	0	0	0	0	0	0
43	Street Lighting & Signal		(63,042)	StLgt-Lamps	0	0	0	0	0	0	0	(31,521)	(31,521)	0
44	General Plant		177,001	SecC-Lab	136,954	774	24,904	27	10,901	28	32	1,640	1,640	102
45	Total DEPRECIATION RESE	108	3,774,461		2,955,942	16,711	537,522	573	315,314	804	5,915	(29,881)	(29,881)	1,443
46														
47	**III. OTHER RATE BASE I**													
48	Cash Working Capital	131	34,988	SecC-OpExp	27,141	153	4,935	5	2,244	6	12	236	236	19
49	CWIP	131	0	SecC-Pt	0	0	0	0	0	0	0	0	0	0
50	Materials & Supplies	255	16,758	SecC-Pt	12,766	72	2,321	2	1,286	3	21	140	140	7
51	Customer Deposits		0	CustDeposits	0	0	0	0	0	0	0	0	0	0
52	ADIT	154	(7,137)	SecC-Pt	(5,437)	(31)	(989)	(1)	(548)	(1)	(9)	(59)	(59)	(3)
53	Accrued Pension / OPEB	182	(1,196)	SecC-Lab	(926)	(5)	(168)	(0)	(74)	(0)	(0)	(11)	(11)	(1)
54	Total OTHER RATE BASE	131-283	43,413		33,544	190	6,100	7	2,909	7	23	305	305	23
55														
56	**TOTAL RATE BASE**		4,448,406		3,308,685	18,705	601,667	641	315,058	804	4,151	98,363	98,363	1,970
57														

SecnCus
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Line	Account	No.	Balance	Allocator	RS	RSAE	NRS	NRH	CS	CSH	IS	MSL	POL	EX
58	**I. OPERATING AND MAINTENANCE EXPENSES**													
59	**B. TRANSMISSION EXPENSE**													
60	Transmission Expense		0	None	0	0	0	0	0	0	0	0	0	0
61	Total TRANSMISSION Expe		0		0	0	0	0	0	0	0	0	0	0
62														
63	**C. DISTRIBUTION EXPENSE**													
64	Ops Supv & Engineering	580	0	SecC-Lab	0	0	0	0	0	0	0	0	0	0
65	Station Expenses	582	0	None	0	0	0	0	0	0	0	0	0	0
66	OH Line Expenses	583	561	Avg-Cust-Sec	443	3	81	0	34	0	0	0	0	0
67	Street Lighting Expenses	585	267	StLgt-Lamps	0	0	0	0	0	0	0	134	134	0
68	Meter Expenses	586	0	None	0	0	0	0	0	0	0	0	0	0
69	Customer Install. expense	587	0	None	0	0	0	0	0	0	0	0	0	0
70	Misc. Distribution Expenses	588	24,667	Avg-Cust-Sec	19,505	110	3,547	4	1,482	4	0	0	0	15
71	Rents	589	7,459	Avg-Cust-Sec	5,898	33	1,073	1	448	1	0	0	0	5
72	Maint Supv & Engineering	590	9,532	SecC-Lab	7,376	42	1,341	1	587	1	2	88	88	5
73	Maint of Station Equip	592	0	None	0	0	0	0	0	0	0	0	0	0
74	Maint of OH Lines	593	91,803	Avg-Cust-Sec	72,592	410	13,201	14	5,516	14	0	0	0	56
75	Maint of UG Lines	594	6,240	Avg-Cust-Sec	4,934	28	897	1	375	1	0	0	0	4
76	Maint of Line Transformers	595	6,253	Avg-Cust-Sec	4,945	28	899	1	376	1	0	0	0	4
77	Maint of Lighting	596	942	StLgt-Lamps	0	0	0	0	0	0	0	471	471	0
78	Maint of Misc. Plant	599	16,945	SecC-Pt	12,909	73	2,347	3	1,300	3	21	141	141	7
79	Total DISTR. O&M EXP.	500-599	164,671		128,603	727	23,386	25	10,117	26	23	834	834	96
80	Distribution Expense		164,671		128,603	727	23,386	25	10,117	26	23	834	834	96
81	**D. CUSTOMER ACCOUNTS AND SERVICE**													
82	Supervision	901	0	None	0	0	0	0	0	0	0	0	0	0
83	Meter Reading Exp	902	0	None	0	0	0	0	0	0	0	0	0	0
84	Customer Records & Coll	903	0	None	0	0	0	0	0	0	0	0	0	0
85	Uncollectible Accounts	904	0	None	0	0	0	0	0	0	0	0	0	0
86	Subtotal - Cust. Accts. Exp.	901-905	0		0	0	0	0	0	0	0	0	0	0
87														
88	Customer Assistance	908	0	None	0	0	0	0	0	0	0	0	0	0
89	OPEN	916	0	None	0	0	0	0	0	0	0	0	0	0
90	Subtotal - Cust. Svce. & Info.	908-916	0		0	0	0	0	0	0	0	0	0	0
91	Total CUST. ACCT. & SERV	901-919	0		0	0	0	0	0	0	0	0	0	0
92														

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Wellsboro Electric Company
Embedded Cost of Service Study (ECOSS)
FPFTY Ending December 31, 2026
Class Allocation- Secondary Customer

Line	Account	No.	Balance	Allocator	RS	RSAE	NRS	NRH	CS	CSH	IS	MSL	POL	EX
93	**E. ADMINISTRATIVE AND GENERAL**													
94	Admin. & Gen'l. Salaries	920	55,070	SecC-Lab	42,610	241	7,748	8	3,392	9	10	510	510	32
95	Office Supplies & Expenses	921	6,630	SecC-Lab	5,130	29	933	1	408	1	1	61	61	4
96	Outside Services Employed	923	17,709	SecC-LabPt	13,597	77	2,472	3	1,225	3	12	156	156	9
97	Property Insurance	924	11,318	SecC-Pt	8,622	49	1,568	2	868	2	14	94	94	5
98	Employee Pensions & Benefits	926	0	SecC-Lab	0	0	0	0	0	0	0	0	0	0
99	Regulatory Comm. Expense	928	0	SecC-Pt	0	0	0	0	0	0	0	0	0	0
100	Misc. General Expense	930	12,673	SecC-LabPt	9,730	55	1,769	2	876	2	9	112	112	6
101	Rents	931	133	SecC-Lab	103	1	19	0	8	0	0	1	1	0
102	Maint General Property	932	24,613	SecC-Pt	18,750	106	3,410	4	1,888	5	30	205	205	10
103	Total A&G Expense	920-932	128,146		98,542	557	17,919	19	8,665	22	77	1,140	1,140	65
104														
105	TOTAL OPERATING EXPENSES		292,817		227,145	1,284	41,305	44	18,782	48	99	1,974	1,974	162
106														
107	**II. DEPRECIATION EXPENSE**													
108	Intangible Plant		0	None	0	0	0	0	0	0	0	0	0	0
109	Station Equipment		0	None	0	0	0	0	0	0	0	0	0	0
110	Poles, Towers and Fixtures		53,423	Avg-Cust-Sec	42,244	239	7,682	8	3,210	8	0	0	0	33
111	OH Conductors and Devices		24,508	Avg-Cust-Sec	19,379	110	3,524	4	1,472	4	0	0	0	15
112	UG Conduits and Conductors		6,957	Avg-Cust-Sec	5,501	31	1,000	1	418	1	0	0	0	4
113	Line Transformers		90,387	Avg-Cust-Sec	71,472	404	12,997	14	5,431	14	0	0	0	55
114	Services		95,347	Services_Cost	70,505	399	12,821	14	11,200	29	381	0	0	0
115	Meters		0	None	0	0	0	0	0	0	0	0	0	0
116	Install. Customers' premises		0	None	0	0	0	0	0	0	0	0	0	0
117	Street Lighting & Signal		2,971	StLgt-Lamps	0	0	0	0	0	0	0	1,485	1,485	0
118	General Plant		31,474	SecC-Lab	24,353	138	4,429	5	1,938	5	6	292	292	18
119	Total DEPRECIATION Exp.	403	305,067		233,455	1,320	42,452	45	23,669	60	387	1,777	1,777	126
120														
121	**III. TAXES and OTHER**													
122	**A. GENERAL TAXES**													
123	Payroll related	408	0	SecC-Lab	0	0	0	0	0	0	0	0	0	0
124	PURTA, Real estate	408.16	7,982	SecC-Pt	6,081	34	1,106	1	612	2	10	67	67	3
125	Capital stock		0	RateBase	0	0	0	0	0	0	0	0	0	0
126	Other	408	154	SecC-Pt	118	1	21	0	12	0	0	1	1	0
127	Subtotal - General Taxes		8,136		6,198	35	1,127	1	624	2	10	68	68	3
128														
129	**B. GROSS RECEIPTS TAX**													
130	Gross Receipts tax		44,841	Dist_Rev	23,609	172	3,493	5	10,664	7	6,164	95	570	63
131	Subtotal- Gross Receipts tax		44,841		23,609	172	3,493	5	10,664	7	6,164	95	570	63
132														

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Wellsboro Electric Company
Embedded Cost of Service Study (ECOSS)
FPFTY Ending December 31, 2026
Class Allocation- Secondary Customer

Line	Account	No.	Balance	Allocator	RS	RSAE	NRS	NRH	CS	CSH	IS	MSL	POL	EX
133	**B. FEDERAL / STATE INCOME TAXES**													
134	State Income Tax Expense		(26,949)	PreStaTax	(14,892)	(149)	(1,953)	(10)	(6,074)	(20)	(3,683)	(55)	(84)	(28)
135	Federal Income Tax Expense		(16,818)	PreFedTax	(9,294)	(93)	(1,219)	(6)	(3,791)	(13)	(2,299)	(34)	(52)	(17)
136	Subtotal - Fed / State Inc Tax	409-411	(43,766)		(24,186)	(242)	(3,171)	(16)	(9,865)	(33)	(5,982)	(89)	(137)	(45)
137	Total TAXES	408-411	9,211		5,621	(35)	1,448	(10)	1,423	(24)	192	73	501	21
138														
139	**TOTAL EXPENSES**		607,096		466,221	2,569	85,206	79	43,875	84	678	3,824	4,252	309
140														
141	**IV. OPERATING REVENUES at Present Rates**													
142	Distribution Revenue		763,714	Dist_Rev	402,106	2,934	59,484	81	181,621	123	104,980	1,610	9,707	1,068
143	Forfeited Discounts		0	None	0	0	0	0	0	0	0	0	0	0
144	Rent For Electric Property		28,680	Avg-Cust-Sec	22,679	128	4,124	4	1,723	4	0	0	0	18
145	Other Electric Revenues		2,732	Dist_Rev	1,438	10	213	0	650	0	375	6	35	4
146	Total REVENUES		795,126		426,223	3,073	63,821	85	183,994	127	105,356	1,616	9,742	1,090
147														
148	TOTAL EXPENSES		607,096		466,221	2,569	85,206	79	43,875	84	678	3,824	4,252	309
149	**V. NET INCOME at Present Rates**		188,030		(39,998)	503	(21,385)	6	140,119	43	104,678	(2,208)	5,490	781
150														
151	**SUMMARY REPORT**													
152	OPERATING REVENUES													
153	Utility Revenues	440-446	763,714		402,106	2,934	59,484	81	181,621	123	104,980	1,610	9,707	1,068
154	Other Operating Revenues	450-456	31,412		24,117	139	4,337	5	2,373	5	375	6	35	21
155	Total Operating Revenues		795,126		426,223	3,073	63,821	85	183,994	127	105,356	1,616	9,742	1,090
156														
157	OPERATING EXPENSES													
158	Distribution / Transmission	580-599	164,671		128,603	727	23,386	25	10,117	26	23	834	834	96
159	Customer Acctg & Service	901-919	0		0	0	0	0	0	0	0	0	0	0
160	Admin & General	920-932	128,146		98,542	557	17,919	19	8,665	22	77	1,140	1,140	65
161	Total Operating Expenses		292,817		227,145	1,284	41,305	44	18,782	48	99	1,974	1,974	162
162														
163	Depreciation Expense	403	305,067		233,455	1,320	42,452	45	23,669	60	387	1,777	1,777	126
164	Taxes Other Than Income	408	52,977		29,808	207	4,620	6	11,288	9	6,174	162	638	66
165	INCOME BEFORE INCOME		144,264		(64,184)	261	(24,556)	(10)	130,254	10	98,696	(2,297)	5,353	736
166	Income Taxes	409-411	(43,766)		(24,186)	(242)	(3,171)	(16)	(9,865)	(33)	(5,982)	(89)	(137)	(45)
167	**NET INCOME**		188,030		(39,998)	503	(21,385)	6	140,119	43	104,678	(2,208)	5,490	781
168														
169	**RATE BASE**		4,448,406		3,308,685	18,705	601,667	641	315,058	804	4,151	98,363	98,363	1,970
170	Return on Rate Base		4.23%											
171														

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Wellsboro Electric Company
Embedded Cost of Service Study (ECOSS)
FPFTY Ending December 31, 2026
Class Allocation- Secondary Customer

Line	Account	No.	Balance	Allocator	RS	RSAE	NRS	NRH	CS	CSH	IS	MSL	POL	EX
172	**REVENUE REQUIREMENTS**													
173	Target Rate of Return		8.1800%		8.1800%	8.1800%	8.1800%	8.1800%	8.1800%	8.1800%	8.1800%	8.1800%	8.1800%	8.1800%
174														
175	Rate Base		4,448,406		3,308,685	18,705	601,667	641	315,058	804	4,151	98,363	98,363	1,970
176														
177	Operating expenses		292,817		227,145	1,284	41,305	44	18,782	48	99	1,974	1,974	162
178	Uncollectibles expense		0	None	0	0	0	0	0	0	0	0	0	0
179	Depreciation expense		305,067		233,455	1,320	42,452	45	23,669	60	387	1,777	1,777	126
180	Regulatory Commission Expenses		28,270	SecC-Pt	21,536	122	3,916	4	2,169	6	35	236	236	12
181	General taxes / Other		8,136		6,198	35	1,127	1	624	2	10	68	68	3
182	Subtotal- Operating Costs to recover		634,291		488,333	2,761	88,801	95	45,244	115	531	4,054	4,054	302
183														
184	Target Return on Rate Base- After tax		363,880		270,650	1,530	49,216	52	25,772	66	340	8,046	8,046	161
185														
186	Income taxes to recover		111,574	30.66%	82,988	469	15,091	16	7,902	20	104	2,467	2,467	49
187														
188	Subtotal- Rev Req before GRT		1,109,744		841,971	4,760	153,108	163	78,918	201	974	14,567	14,567	513
189	GRT needed		67,611	6.27%	51,279	290	9,328	10	4,799	12	38	913	911	31
190	**TOTAL REVENUE REQUIREMEN**		1,177,355		893,250	5,050	162,436	173	83,718	214	1,012	15,480	15,479	544
191														
192	Revenue at Present rates		795,126		426,223	3,073	63,821	85	183,994	127	105,356	1,616	9,742	1,090
193	Revenue Excess (Deficiency)		(382,229)		(467,027)	(1,977)	(98,615)	(88)	100,276	(86)	104,344	(13,865)	(5,737)	546
194														

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Class Allocation- Billing Customer
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Wellsboro Electric Company
Embedded Cost of Service Study (ECOSS)
FPFTY Ending December 31, 2026
Class Allocation- Billing Customer

Line	Account	No.	Balance	Allocator	RS	RSAE	NRS	NRH	CS	CSH	IS	MSL	POL	EX
1	**I. ELECTRIC PLANT IN SERVICE**													
2	INTANGIBLE PLANT													
3	EDI Software	303	284,588	Avg-Cust	224,575	1,270	40,838	44	17,064	44	580	0	0	174
4	Total INTANGIBLE Plant		284,588		224,575	1,270	40,838	44	17,064	44	580	0	0	174
5														
6	**C. TRANSMISSION PLANT**													
7	Transmission Plant	361	0	None	0	0	0	0	0	0	0	0	0	0
8	Total TRANSMISSION Plant	350-359	0		0	0	0	0	0	0	0	0	0	0
9														
10	**D. DISTRIBUTION PLANT**													
11	Land & Land Rights	360	0	None	0	0	0	0	0	0	0	0	0	0
12	Structures and improvements	361	0	None	0	0	0	0	0	0	0	0	0	0
13	Station Equipment	362	0	None	0	0	0	0	0	0	0	0	0	0
14	Poles, Tower & Fixtures	364	0	None	0	0	0	0	0	0	0	0	0	0
15	OH Conductors & Devices	365	0	None	0	0	0	0	0	0	0	0	0	0
16	UG Conduits and Conductors	366	0	None	0	0	0	0	0	0	0	0	0	0
17	Line Transformers	368	0	None	0	0	0	0	0	0	0	0	0	0
18	Services	369	0	None	0	0	0	0	0	0	0	0	0	0
19	Meters	370	1,041,481	Meter_Cost	626,754	3,543	113,972	121	226,766	578	53,651	0	0	16,095
20	Install. Customers' premises	371	519,618	Avg-Cust	410,043	2,318	74,564	79	31,156	79	1,060	0	0	318
21	Street Lighting & Signal	373	0	StLgt-Lamps	0	0	0	0	0	0	0	0	0	0
22	Total DISTRIBUTION Plant	360-373	1,561,098		1,036,797	5,861	188,536	201	257,921	658	54,710	0	0	16,413
23														
24	**E. GENERAL PLANT**													
25	General Plant	389	4,203,861	Bill-Lab	3,239,628	18,315	589,109	628	317,534	810	29,105	0	0	8,732
26	Communication Equip	398	50,686	Bill-Lab	39,060	221	7,103	8	3,829	10	351	0	0	105
27	Total GENERAL Plant	389-399	4,254,547		3,278,688	18,536	596,212	636	321,363	820	29,456	0	0	8,837
28														
29	**TOTAL UTILITY PLANT**		6,100,233		4,540,060	25,667	825,586	880	596,348	1,521	84,747	0	0	25,424
30														

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Wellsboro Electric Company
Embedded Cost of Service Study (ECOSS)
FPFTY Ending December 31, 2026
Class Allocation- Billing Customer

Line	Account	No.	Balance	Allocator	RS	RSAE	NRS	NRH	CS	CSH	IS	MSL	POL	EX
31	**II. DEPRECIATION RESERVE**													
32	Intangible Plant		284,588	Avg-Cust	224,575	1,270	40,838	44	17,064	44	580	0	0	174
33	Transmission Plant		0	None	0	0	0	0	0	0	0	0	0	0
34	Structures and improvements		0	None	0	0	0	0	0	0	0	0	0	0
35	Station Equipment		0	None	0	0	0	0	0	0	0	0	0	0
36	Poles, Towers and Fixtures		0	None	0	0	0	0	0	0	0	0	0	0
37	OH Conductors and Devices		0	None	0	0	0	0	0	0	0	0	0	0
38	UG Conduits and Conductors		0	None	0	0	0	0	0	0	0	0	0	0
39	Line Transformers		0	None	0	0	0	0	0	0	0	0	0	0
40	Services		0	None	0	0	0	0	0	0	0	0	0	0
41	Meters		787,559	Meter_Cost	473,946	2,679	86,185	92	171,478	437	40,570	0	0	12,171
42	Install. Customers' premises		115,728	Avg-Cust	91,324	516	16,607	18	6,939	18	236	0	0	71
43	Street Lighting & Signal		0	StLgt-Lamps	0	0	0	0	0	0	0	0	0	0
44	General Plant		1,259,090	Bill-Lab	970,294	5,485	176,443	188	95,104	243	8,717	0	0	2,615
45	Total DEPRECIATION RESE	108	2,446,965		1,760,140	9,951	320,072	341	290,585	741	50,104	0	0	15,031
46														
47	**III. OTHER RATE BASE I**													
48	Cash Working Capital	131	219,001	Bill-OpExp	165,996	986	29,335	37	18,376	50	3,687	79	102	353
49	CWIP	131	0	Bill-Pt	0	0	0	0	0	0	0	0	0	0
50	Materials & Supplies	255	104,895	Bill-Pt	77,837	440	14,154	15	10,448	27	1,518	0	0	455
51	Customer Deposits		(195,713)	CustDeposits	(112,853)	(829)	(10,984)	(29)	(44,236)	(22)	(25,342)	0	(1,164)	(255)
52	ADIT	154	(5,075)	Bill-Pt	(3,766)	(21)	(685)	(1)	(505)	(1)	(73)	0	0	(22)
53	Accrued Pension / OPEB	182	(8,511)	Bill-Lab	(6,559)	(37)	(1,193)	(1)	(643)	(2)	(59)	0	0	(18)
54	Total OTHER RATE BASE	131-283	114,597		120,656	539	30,628	20	(16,560)	52	(20,270)	79	(1,062)	514
55														
56	**TOTAL RATE BASE**		3,767,865		2,900,577	16,255	536,141	559	289,203	832	14,373	79	(1,062)	10,907
57														

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Wellsboro Electric Company
Embedded Cost of Service Study (ECOSS)
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Class Allocation- Billing Customer

Line	Account	No.	Balance	Allocator	RS	RSAE	NRS	NRH	CS	CSH	IS	MSL	POL	EX
58	**I. OPERATING AND MAINTENANCE EXPENSES**													
59	**B. TRANSMISSION EXPENSE**													
60	Transmission Expense		0	None	0	0	0	0	0	0	0	0	0	0
61	Total TRANSMISSION Expe		0		0	0	0	0	0	0	0	0	0	0
62														
63	**C. DISTRIBUTION EXPENSE**													
64	Ops Supv & Engineering	580	0	Bill-DxLab	0	0	0	0	0	0	0	0	0	0
65	Station Expenses	582	0	None	0	0	0	0	0	0	0	0	0	0
66	OH Line Expenses	583	0	None	0	0	0	0	0	0	0	0	0	0
67	Street Lighting Expenses	585	0	StLgt-Lamps	0	0	0	0	0	0	0	0	0	0
68	Meter Expenses	586	39,903	Meter_Cost	24,013	136	4,367	5	8,688	22	2,056	0	0	617
69	Customer Install. expense	587	267	Avg-Cust	211	1	38	0	16	0	1	0	0	0
70	Misc. Distribution Expenses	588	0	Avg-Cust	0	0	0	0	0	0	0	0	0	0
71	Rents	589	1,598	Bill-Pt	1,186	7	216	0	159	0	23	0	0	7
72	Maint Supv & Engineering	590	494	Bill-DxLab	302	2	55	0	104	0	24	0	0	7
73	Maint of Station Equip	592	0	None	0	0	0	0	0	0	0	0	0	0
74	Maint of OH Lines	593	0	None	0	0	0	0	0	0	0	0	0	0
75	Maint of UG Lines	594	0	None	0	0	0	0	0	0	0	0	0	0
76	Maint of Line Transformers	595	0	None	0	0	0	0	0	0	0	0	0	0
77	Maint of Lighting	596	0	StLgt-Lamps	0	0	0	0	0	0	0	0	0	0
78	Maint of Misc. Plant	599	3,630	Bill-Pt	2,694	15	490	1	362	1	53	0	0	16
79	Total DISTR. O&M EXP.	500-599	45,893		28,406	161	5,165	6	9,329	24	2,156	0	0	647
80	Distribution Expense		45,893		28,406	161	5,165	6	9,329	24	2,156	0	0	647
81	**D. CUSTOMER ACCOUNTS AND SERVICE**													
82	Supervision	901	0	Avg-Cust	0	0	0	0	0	0	0	0	0	0
83	Meter Reading Exp	902	16,544	Meter_Cost	9,956	56	1,810	2	3,602	9	852	0	0	256
84	Customer Records & Coll	903	1,047,510	Avg-Cust	826,616	4,673	150,316	160	62,807	160	2,136	0	0	641
85	Uncollectible Accounts	904	20,000	Write-Offs	17,398	128	331	1	1,334	1	764	0	35	8
86	Subtotal - Cust. Accts. Exp.	901-905	1,084,054		853,970	4,857	152,457	163	67,744	170	3,753	0	35	904
87														
88	Customer Assistance	908	9,737	Avg-Cust	7,684	43	1,397	1	584	1	20	0	0	6
89	OPEN	916	0	None	0	0	0	0	0	0	0	0	0	0
90	Subtotal - Cust. Svce. & Info.	908-916	9,737		7,684	43	1,397	1	584	1	20	0	0	6
91	Total CUST. ACCT. & SERV	901-919	1,093,791		861,654	4,901	153,855	165	68,328	172	3,773	0	35	910
92														

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Class Allocation- Billing Customer
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Wellsboro Electric Company
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FPFTY Ending December 31, 2026
Class Allocation- Billing Customer

Line	Account	No.	Balance	Allocator	RS	RSAE	NRS	NRH	CS	CSH	IS	MSL	POL	EX
93	**E. ADMINISTRATIVE AND GENERAL**													
94	Admin. & Gen'l. Salaries	920	391,740	Bill-Lab	301,888	1,707	54,897	59	29,590	75	2,712	0	0	814
95	Office Supplies & Expenses	921	47,165	Bill-Lab	36,347	205	6,609	7	3,563	9	327	0	0	98
96	Outside Services Employed	923	43,340	Bill-LabPt	32,779	185	5,961	6	3,795	10	464	0	0	139
97	Property Insurance	924	8,047	Bill-Pt	5,971	34	1,086	1	802	2	116	0	0	35
98	Employee Pensions & Benefits	926	0	Bill-Lab	0	0	0	0	0	0	0	0	0	0
99	Regulatory Comm. Expense	928	153,393	RateBase	85,012	852	11,175	56	33,852	114	20,715	663	820	134
100	Misc. General Expense	930	31,014	Bill-LabPt	23,457	133	4,266	5	2,716	7	332	0	0	100
101	Rents	931	946	Bill-Lab	729	4	133	0	71	0	7	0	0	2
102	Maint General Property	932	17,500	Bill-Pt	12,986	73	2,361	3	1,743	4	253	0	0	76
103	Total A&G Expense	920-932	693,144		499,169	3,193	86,488	136	76,132	221	24,926	663	820	1,397
104														
105	TOTAL OPERATING EXPENSES		1,832,829		1,389,229	8,255	245,508	306	153,788	417	30,854	663	855	2,954
106														
107	**II. DEPRECIATION EXPENSE**													
108	Intangible Plant		0	Avg-Cust	0	0	0	0	0	0	0	0	0	0
109	Station Equipment		0	None	0	0	0	0	0	0	0	0	0	0
110	Poles, Towers and Fixtures		0	None	0	0	0	0	0	0	0	0	0	0
111	OH Conductors and Devices		0	None	0	0	0	0	0	0	0	0	0	0
112	UG Conduits and Conductors		0	None	0	0	0	0	0	0	0	0	0	0
113	Line Transformers		0	None	0	0	0	0	0	0	0	0	0	0
114	Services		0	None	0	0	0	0	0	0	0	0	0	0
115	Meters		79,809	Meter_Cost	48,028	272	8,734	9	17,377	44	4,111	0	0	1,233
116	Install. Customers' premises		53,884	Avg-Cust	42,521	240	7,732	8	3,231	8	110	0	0	33
117	Street Lighting & Signal		0	StLgt-Lamps	0	0	0	0	0	0	0	0	0	0
118	General Plant		223,892	Bill-Lab	172,538	975	31,375	33	16,911	43	1,550	0	0	465
119	Total DEPRECIATION Exp.	403	357,586		263,088	1,487	47,841	51	37,519	96	5,771	0	0	1,731
120														
121	**III. TAXES and OTHER**													
122	**A. GENERAL TAXES**													
123	Payroll related	408	0	None	0	0	0	0	0	0	0	0	0	0
124	PURTA, Real estate	408.16	5,675	Bill-Pt	4,211	24	766	1	565	1	82	0	0	25
125	Capital stock		0	RateBase	0	0	0	0	0	0	0	0	0	0
126	Other	408	110	Bill-Pt	81	0	15	0	11	0	2	0	0	0
127	Subtotal - General Taxes		5,785		4,293	24	781	1	576	1	84	0	0	25
128														
129	**B. GROSS RECEIPTS TAX**													
130	Gross Receipts tax		110,058	Dist_Rev	57,947	423	8,572	12	26,173	18	15,129	232	1,399	154
131	Subtotal- Gross Receipts tax		110,058		57,947	423	8,572	12	26,173	18	15,129	232	1,399	154
132														

BillCus
Class Allocation- Billing Customer
CAl
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Wellsboro Electric Company
Embedded Cost of Service Study (ECOSS)
FPFTY Ending December 31, 2026
Class Allocation- Billing Customer

Line	Account	No.	Balance	Allocator	RS	RSAE	NRS	NRH	CS	CSH	IS	MSL	POL	EX
133	**B. FEDERAL / STATE INCOME TAXES**													
134	State Income Tax Expense		0	PreStaTax	0	0	0	0	0	0	0	0	0	0
135	Federal Income Tax Expense		0	PreFedTax	0	0	0	0	0	0	0	0	0	0
136	Subtotal - Fed / State Inc Tax	409-411	0		0	0	0	0	0	0	0	0	0	0
137	Total TAXES	408-411	115,842		62,240	447	9,353	12	26,749	19	15,212	232	1,399	179
138														
139	**TOTAL EXPENSES**		2,306,257		1,714,557	10,189	302,702	370	218,057	532	51,838	895	2,254	4,865
140														
141	**IV. OPERATING REVENUES at Present Rates**													
142	Distribution Revenue		1,843,328	Dist_Rev	970,538	7,081	143,573	195	438,367	296	253,384	3,886	23,429	2,579
143	Forfeited Discounts		31,122	Write-Offs	27,073	199	516	1	2,076	1	1,189	0	55	12
144	Rent For Electric Property		0	None	0	0	0	0	0	0	0	0	0	0
145	Other Electric Revenues		6,593	Dist_Rev	3,471	25	514	1	1,568	1	906	14	84	9
146	Total REVENUES		1,881,044		1,001,083	7,306	144,602	197	442,011	298	255,480	3,900	23,567	2,600
147														
148	TOTAL EXPENSES		2,306,257		1,714,557	10,189	302,702	370	218,057	532	51,838	895	2,254	4,865
149	**V. NET INCOME at Present Rates**		(425,213)		(713,474)	(2,883)	(158,100)	(173)	223,954	(234)	203,642	3,005	21,314	(2,265)
150														
151	**SUMMARY REPORT**													
152	OPERATING REVENUES													
153	Utility Revenues	440-446	1,874,450		997,611	7,280	144,088	196	440,443	297	254,574	3,886	23,484	2,591
154	Other Operating Revenues	450-456	6,593		3,471	25	514	1	1,568	1	906	14	84	9
155	Total Operating Revenues		1,881,044		1,001,083	7,306	144,602	197	442,011	298	255,480	3,900	23,567	2,600
156														
157	OPERATING EXPENSES													
158	Distribution / Transmission	580-599	45,893		28,406	161	5,165	6	9,329	24	2,156	0	0	647
159	Customer Acctg & Service	901-919	1,093,791		861,654	4,901	153,855	165	68,328	172	3,773	0	35	910
160	Admin & General	920-932	693,144		499,169	3,193	86,488	136	76,132	221	24,926	663	820	1,397
161	Total Operating Expenses		1,832,829		1,389,229	8,255	245,508	306	153,788	417	30,854	663	855	2,954
162														
163	Depreciation Expense	403	357,586		263,088	1,487	47,841	51	37,519	96	5,771	0	0	1,731
164	Taxes Other Than Income	408	115,842		62,240	447	9,353	12	26,749	19	15,212	232	1,399	179
165	INCOME BEFORE INCOME		(425,213)		(713,474)	(2,883)	(158,100)	(173)	223,954	(234)	203,642	3,005	21,314	(2,265)
166	Income Taxes	409-411	0		0	0	0	0	0	0	0	0	0	0
167	**NET INCOME**		(425,213)		(713,474)	(2,883)	(158,100)	(173)	223,954	(234)	203,642	3,005	21,314	(2,265)
168														
169	**RATE BASE**		3,767,865		2,900,577	16,255	536,141	559	289,203	832	14,373	79	(1,062)	10,907
170	Return on Rate Base		-11.29%											
171														

BillCus
Class Allocation- Billing Customer
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Wellsboro Electric Company
Embedded Cost of Service Study (ECOSS)
FPFTY Ending December 31, 2026
Class Allocation- Billing Customer

Line	Account	No.	Balance	Allocator	RS	RSAE	NRS	NRH	CS	CSH	IS	MSL	POL	EX
172	**REVENUE REQUIREMENTS**													
173	Target Rate of Return		8.1800%		8.1800%	8.1800%	8.1800%	8.1800%	8.1800%	8.1800%	8.1800%	8.1800%	8.1800%	8.1800%
174														
175	Rate Base		3,767,865		2,900,577	16,255	536,141	559	289,203	832	14,373	79	(1,062)	10,907
176														
177	Operating expenses		1,659,436		1,286,819	7,275	234,001	249	118,602	303	9,375	0	0	2,812
178	Uncollectibles expense		20,000	Write-Offs	17,398	128	331	1	1,334	1	764	0	35	8
179	Depreciation expense		357,586		263,088	1,487	47,841	51	37,519	96	5,771	0	0	1,731
180	Regulatory Commission Expenses		20,100	Bill-Pt	14,915	84	2,712	3	2,002	5	291	0	0	87
181	General taxes / Other		5,785		4,293	24	781	1	576	1	84	0	0	25
182	Subtotal- Operating Costs to recover		2,062,907		1,586,513	8,999	285,666	305	160,034	406	16,285	0	35	4,664
183														
184	Target Return on Rate Base- After tax		308,211		237,267	1,330	43,856	46	23,657	68	1,176	6	(87)	892
185														
186	Income taxes to recover		94,505	30.66%	72,752	408	13,447	14	7,254	21	361	2	(27)	274
187														
188	Subtotal- Rev Req before GRT		2,465,623		1,896,532	10,736	342,970	365	190,944	494	17,821	8	(78)	5,830
189	GRT needed		152,228	6.27%	116,996	659	21,439	23	11,744	31	986	(0)	(14)	364
190	**TOTAL REVENUE REQUIREMEN**		2,617,851		2,013,528	11,395	364,410	388	202,688	525	18,807	8	(92)	6,194
191														
192	Revenue at Present rates		1,881,044		1,001,083	7,306	144,602	197	442,011	298	255,480	3,900	23,567	2,600
193	Revenue Excess (Deficiency)		(736,807)		(1,012,445)	(4,089)	(219,808)	(191)	239,323	(227)	236,673	3,892	23,659	(3,594)
194														

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Wellsboro Electric Company
Embedded Cost of Service Study (ECOSS)
FPFTY Ending December 31, 2026
Allocator Assignments

Line	Account	No.	Balance	Function	Classify	Class Allocation			
				Allocator	Secondary	PrimDem	SecnDem	SecnCus	BillCus ×
1	**I. ELECTRIC PLANT IN SERVICE**								
2	INTANGIBLE PLANT								
3	EDI Software	303	284,588	Bill	-	-	-	-	Avg-Cust
4	Total INTANGIBLE Plant		284,588						
5									
6	**C. TRANSMISSION PLANT**								
7	Transmission Plant	361	0	-	-	-	-	-	-
8	Total TRANSMISSION Plant	350-359	0						
9									
10	**D. DISTRIBUTION PLANT**								
11	Land & Land Rights	360	178,334	Prim	-	NCP-Prim	-	-	-
12	Structures and improvements	361	0	-	-	-	-	-	-
13	Station Equipment	362	3,992,800	Prim	-	NCP-Prim	-	-	-
14	Poles, Tower & Fixtures	364	14,933,172	OH_Cond	PTF-Sec-Z	NCP-Prim	NCP-Sec	Avg-Cust-Sec	-
15	OH Conductors & Devices	365	6,804,947	OH_Cond	OH-Sec-Z	NCP-Prim	NCP-Sec	Avg-Cust-Sec	-
16	UG Conduits and Conductors	366	1,038,449	UG_Cond	UG-Sec-Z	NCP-Prim	NCP-Sec	Avg-Cust-Sec	-
17	Line Transformers	368	3,365,587	Trans	Trans-Min	-	NCP-Ltr	Avg-Cust-Sec	-
18	Services	369	2,486,089	Sec	Customer	-	-	Services_Cost	-
19	Meters	370	1,041,481	Bill	-	-	-	-	Meter_Cost
20	Install. Customers' premises	371	519,618	Bill	-	-	-	-	Avg-Cust
21	Street Lighting & Signal	373	125,272	Sec	Customer	-	-	StLgt-Lamps	-
22	Total DISTRIBUTION Plant	360-373	34,485,748						
23									
24	**E. GENERAL PLANT**								
25	General Plant	389	9,778,618	Labor	Sec-Lab	PriD-Lab	SecD-Lab	SecC-Lab	Bill-Lab
26	Communication Equip	398	117,901	Labor	Sec-Lab	PriD-Lab	SecD-Lab	SecC-Lab	Bill-Lab
27	Total GENERAL Plant	389-399	9,896,519						
28									
29	**TOTAL UTILITY PLANT**		44,666,856						
30									

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Wellsboro Electric Company
Embedded Cost of Service Study (ECOSS)
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Allocator Assignments

Line	Account	No.	Balance	Function Allocator	Classify Secondary	Class Allocation PrimDem	SecnDem	SecnCus	BillCus ×
31	**II. DEPRECIATION RESERVE**								
32	Intangible Plant		284,588	IntanPt	-	-	-	-	Avg-Cust
33	Transmission Plant		0	-	-	-	-	-	-
34	Structures and improvements		0	-	-	-	-	-	-
35	Station Equipment		3,892,596	Prim	-	NCP-Prim	-	-	-
36	Poles, Towers and Fixtures		5,102,743	OH_Cond	PTF-Sec-Z	NCP-Prim	NCP-Sec	Avg-Cust-Sec	-
37	OH Conductors and Devices		2,322,844	OH_Cond	OH-Sec-Z	NCP-Prim	NCP-Sec	Avg-Cust-Sec	-
38	UG Conduits and Conductors		779,669	UG_Cond	UG-Sec-Z	NCP-Prim	NCP-Sec	Avg-Cust-Sec	-
39	Line Transformers		1,697,284	Trans	Trans-Min	-	NCP-Ltr	Avg-Cust-Sec	-
40	Services		1,472,321	Sec	Customer	-	-	Services_Cost	-
41	Meters		787,559	Bill	-	-	-	-	Meter_Cost
42	Install. Customers' premises		115,728	Bill	-	-	-	-	Avg-Cust
43	Street Lighting & Signal		(63,042)	Sec	Customer	-	-	StLgt-Lamps	-
44	General Plant		2,928,774	GenPtxL	Sec-GenPt	PriD-Lab	SecD-Lab	SecC-Lab	Bill-Lab
45	Total DEPRECIATION RESE	108	9,279,927						
46									
47	**III. OTHER RATE BASE ITEMS**								
48	Cash Working Capital	131	517,744	OpExp_Dist	Sec-OpExp	PriD-OpExp	SecD-OpExp	SecC-OpExp	Bill-OpExp
49	CWIP	131	0	-	-	-	-	-	-
50	Materials & Supplies	255	247,983	OpExp_Dist	Sec-OpExp	PriD-Pt	SecD-Pt	SecC-Pt	Bill-Pt
51	Customer Deposits		(195,713)	Bill	-	-	-	-	CustDeposits
52	ADIT	154	(38,728)	Plant	Sec-Pt	PriD-Pt	SecD-Pt	SecC-Pt	Bill-Pt
53	Accrued Pension / OPEB	182	(19,798)	Labor	Sec-Lab	PriD-Lab	SecD-Lab	SecC-Lab	Bill-Lab
54	Total OTHER RATE BASE	131-283	511,488						
55									
56	**TOTAL RATE BASE**		35,898,417						
57									

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Wellsboro Electric Company
Embedded Cost of Service Study (ECOSS)
FPFTY Ending December 31, 2026
Allocator Assignments

Line	Account	No.	Balance	Function	Classify	Class Allocation			
				Allocator	Secondary	PrimDem	SecnDem	SecnCus	BillCus ×
58	**I. OPERATING AND MAINTENANCE EXPENSES**								
59	B. TRANSMISSION EXPENSE								
60	Transmission Expense								
61	Total TRANSMISSION Expense								
62									
63	**C. DISTRIBUTION EXPENSE**								
64	Ops Supv & Engineering	580	0	-	-	-	-	-	-
65	Station Expenses	582	0	-	-	-	-	-	-
66	OH Line Expenses	583	6,020	OH_Cond	OH-Sec-Z	NCP-Prim	NCP-Sec	Avg-Cust-Sec	-
67	Street Lighting Expenses	585	267	Sec	Customer	-	-	StLgt-Lamps	-
68	Meter Expenses	586	39,903	Bill	-	-	-	-	Meter_Cost
69	Customer Install. expense	587	267	Bill	-	-	-	-	Avg-Cust
70	Misc. Distribution Expenses	588	285,688	OH_UG	Sec-OH_UG	NCP-Prim	NCP-Sec	Avg-Cust-Sec	-
71	Rents	589	35,300	DistPt	Sec-Pt	NCP-Prim	NCP-Sec	Avg-Cust-Sec	Bill-Pt
72	Maint Supv & Engineering	590	101,784	D-Labor-Mnt	Sec-Lab	PriD-Lab	SecD-Lab	SecC-Lab	Bill-DxLab
73	Maint of Station Equip	592	18,557	Prim	-	NCP-Prim	-	-	-
74	Maint of OH Lines	593	985,327	OH_Cond	OH-Sec-Z	NCP-Prim	NCP-Sec	Avg-Cust-Sec	-
75	Maint of UG Lines	594	40,313	UG_Cond	UG-Sec-Z	NCP-Prim	NCP-Sec	Avg-Cust-Sec	-
76	Maint of Line Transformers	595	8,064	Trans	Trans-Min	-	NCP-Ltr	Avg-Cust-Sec	-
77	Maint of Lighting	596	942	Sec	Customer	-	-	StLgt-Lamps	-
78	Maint of Misc. Plant	599	80,194	DistPt	Sec-Pt	NCP-Prim	NCP-Sec	SecC-Pt	Bill-Pt
79	Total DISTR. O&M EXP.	500-599	1,602,629						
80	Distribution Expense								
81	**D. CUSTOMER ACCOUNTS AND SERVICE**								
82	Supervision	901	0	-	-	-	-	-	-
83	Meter Reading Exp	902	16,544	Bill	-	-	-	-	Meter_Cost
84	Customer Records & Coll	903	1,047,510	Bill	-	-	-	-	Avg-Cust
85	Uncollectible Accounts	904	20,000	Bill	-	-	-	-	Write-Offs
86	Subtotal - Cust. Accts. Exp.	901-905	1,084,054						
87									
88	Customer Assistance	908	9,737	Bill	-	-	-	-	Avg-Cust
89	OPEN	916	0	-	-	-	-	-	-
90	Subtotal - Cust. Svce. & Info.	908-916	9,737						
91	Total CUST. ACCT. & SERV	901-919	1,093,791						
92									

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Wellsboro Electric Company
Embedded Cost of Service Study (ECOSS)
FPFTY Ending December 31, 2026
Allocator Assignments

Line	Account	No.	Balance	Function	Classify	Class Allocation			
				Allocator	Secondary	PrimDem	SecnDem	SecnCus	BillCus ×
93	**E. ADMINISTRATIVE AND GENERAL**								
94	Admin. & Gen'l. Salaries	920	911,229	Labor	Sec-Lab	PriD-Lab	SecD-Lab	SecC-Lab	Bill-Lab
95	Office Supplies & Expenses	921	109,710	Labor	Sec-Lab	PriD-Lab	SecD-Lab	SecC-Lab	Bill-Lab
96	Outside Services Employed	923	154,525	Labor_Pt	Sec-LabPt	PriD-LabPt	SecD-LabPt	SecC-LabPt	Bill-LabPt
97	Property Insurance	924	61,410	Plant	Sec-Pt	PriD-Pt	SecD-Pt	SecC-Pt	Bill-Pt
98	Employee Pensions & Benefits	926	0	-	-	-	-	-	-
99	Regulatory Comm. Expense	928	153,393	Bill	-	-	-	-	RateBase
100	Misc. General Expense	930	110,581	Labor_Pt	Sec-LabPt	PriD-LabPt	SecD-LabPt	SecC-LabPt	Bill-LabPt
101	Rents	931	2,200	Labor	Sec-Lab	PriD-Lab	SecD-Lab	SecC-Lab	Bill-Lab
102	Maint General Property	932	133,551	Plant	Sec-Pt	PriD-Pt	SecD-Pt	SecC-Pt	Bill-Pt
103	Total A&G Expense	920-932	1,636,599						
104									
105	TOTAL OPERATING EXPEI		4,333,019						
106									
107	**II. DEPRECIATION EXPENSE**								
108	Intangible Plant		0	-	-	-	-	-	-
109	Station Equipment		252,375	Prim	-	NCP-Prim	-	-	-
110	Poles, Towers and Fixtures		509,675	OH_Cond	PTF-Sec-Z	NCP-Prim	NCP-Sec	Avg-Cust-Sec	-
111	OH Conductors and Devices		263,041	OH_Cond	OH-Sec-Z	NCP-Prim	NCP-Sec	Avg-Cust-Sec	-
112	UG Conduits and Conductors		44,951	UG_Cond	UG-Sec-Z	NCP-Prim	NCP-Sec	Avg-Cust-Sec	-
113	Line Transformers		116,555	Trans	Trans-Min	-	NCP-Ltr	Avg-Cust-Sec	-
114	Services		95,347	Sec	Customer	-	-	Services_Cost	-
115	Meters		79,809	Bill	-	-	-	-	Meter_Cost
116	Install. Customers' premises		53,884	Bill	-	-	-	-	Avg-Cust
117	Street Lighting & Signal		2,971	Sec	Customer	-	-	StLgt-Lamps	-
118	General Plant		520,797	GenPtxL	Sec-GenPt	PriD-Lab	SecD-Lab	SecC-Lab	Bill-Lab
119	Total DEPRECIATION Exp.	403	762,050						
120									
121	**III. TAXES and OTHER**								
122	**A. GENERAL TAXES**								
123	Payroll related	408	0	-	-	-	-	-	-
124	PURTA, Real estate	408.16	43,311	Plant	Sec-Pt	PriD-Pt	SecD-Pt	SecC-Pt	Bill-Pt
125	Capital stock		0	-	-	-	-	-	-
126	Other	408	837	Plant	Sec-Pt	PriD-Pt	SecD-Pt	SecC-Pt	Bill-Pt
127	Subtotal - General Taxes		44,148						
128									
129	**B. GROSS RECEIPTS TAX**								
130	Gross Receipts tax		377,718	GRT_RevxT	Sec-Rev	Dist_Rev	Dist_Rev	Dist_Rev	Dist_Rev
131	Subtotal- Gross Receipts tax		377,718						
132									

Assigned
Allocator Assignments
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Wellsboro Electric Company
Embedded Cost of Service Study (ECOSS)
FPFTY Ending December 31, 2026
Allocator Assignments

Line	Account	No.	Balance	Function Allocator	Classify Secondary	Class Allocation PrimDem	SecnDem	SecnCus	BillCus ×
133	**B. FEDERAL / STATE INCOME TAXES**								
134	State Income Tax Expense		(86,033)	StaTax	Sec-StaTax	PreStaTax	PreStaTax	PreStaTax	-
135	Federal Income Tax Expense		(53,690)	FedTax	Sec-FedTax	PreFedTax	PreFedTax	PreFedTax	-
136	Subtotal - Fed / State Inc Tax	409-411	(139,723)						
137	Total TAXES	408-411	282,143						
138									
139	**TOTAL EXPENSES**		5,377,211						
140									
141	**IV. OPERATING REVENUES at Present Rates**								
142	Distribution Revenue		6,401,996	DistBill_RR-PF	Sec-RetRRPF	Dist_Rev	Dist_Rev	Dist_Rev	Dist_Rev
143	Forfeited Discounts		31,122	Bill	-	-	-	-	Write-Offs
144	Rent For Electric Property		273,619	OH_Cond	PTF-Sec-Z	NCP-Prim	NCP-Sec	Avg-Cust-Sec	-
145	Other Electric Revenues		22,899	DistBill_RR-PF	Sec-RetRRPF	Dist_Rev	Dist_Rev	Dist_Rev	Dist_Rev
146	Total REVENUES		6,729,636						
147									
148	TOTAL EXPENSES		5,377,211						
149	**V. NET INCOME at Present Rates**		1,352,425						
150									
151	**SUMMARY REPORT**								
152	OPERATING REVENUES								
153	Utility Revenues	440-446	6,433,118						
154	Other Operating Revenues	450-456	296,518						
155	Total Operating Revenues		6,729,636						
156									
157	OPERATING EXPENSES								
158	Distribution / Transmission	580-599	1,602,629						
159	Customer Acctg & Service	901-919	1,093,791						
160	Admin & General	920-932	1,636,599						
161	Total Operating Expenses		4,333,019						
162									
163	Depreciation Expense	403	762,050						
164	Taxes Other Than Income	408	421,866						
165	INCOME BEFORE INCOME		1,212,702						
166	Income Taxes	409-411	(139,723)						
167	**NET INCOME**		1,352,425						
168									
169	**RATE BASE**		35,898,417						
170	Return on Rate Base		3.77%						
171									

Assigned
Allocator Assignments
Fac
E-5A

Wellsboro Electric Company
Embedded Cost of Service Study (ECOSS)
FPFTY Ending December 31, 2026
Allocator Assignments

Line	Account	No.	Balance	Function Allocator	Classify Secondary	Class Allocation PrimDem	SecnDem	SecnCus	BillCus ×
172	**REVENUE REQUIREMENTS**								
173	Target Rate of Return								
174									
175	Rate Base								
176									
177	Operating expenses								
178	Uncollectibles expense		20,000	BILL	-	-	-	-	Write-Offs
179	Depreciation expense								
180	Regulatory Commission Expenses		153,393	Plant	Sec-Pt	PriD-Pt	SecD-Pt	SecC-Pt	Bill-Pt
181	General taxes / Other								
182	Subtotal- Operating Costs to recover								
183									
184	Target Return on Rate Base- After tax								
185									
186	Income taxes to recover								
187									
188	Subtotal- Rev Req before GRT								
189	GRT needed								
190	**TOTAL REVENUE REQUIREMENT**								
191									
192	Revenue at Present rates								
193	Revenue Excess (Deficiency)								
194									

Funcl **Wellsboro Electric Company**
Funct **Embedded Cost of Service Study (ECOSS)**
Fac **FPFTY Ending December 31, 2026**
E-5B **Functionalization Factors**

0	Allocator Name	In Use	Total	Primary	Secondary	Billing	x
1	None		-				x
2		FALSE	0.00%	0.00%	0.00%	0.00%	x
3							x
4	Tran		1				x
5		TRUE	100.00%	0.00%	0.00%	0.00%	x
6							x
7	Prim		1	1			x
8		TRUE	100.00%	100.00%	0.00%	0.00%	x
9							x
10	Sec		1		1		x
11		TRUE	100.00%	0.00%	100.00%	0.00%	x
12							x
13	Bill		1			1	x
14		TRUE	100.00%	0.00%	0.00%	100.00%	x
15							x
16	OH_Cond		1	1	0	-	x
17		TRUE	100.00%	83.37%	16.63%	0.00%	x
18							x
19	UG_Cond		1	1	0	-	x
20		TRUE	100.00%	57.35%	42.65%	0.00%	x
21							x
22	Trans		1	-	1	-	x
23		TRUE	100.00%	0.00%	100.00%	0.00%	x
24							x
25	UG_Total		1,038,449	595,569	442,880	-	x
26		TRUE	100.00%	57.35%	42.65%	0.00%	x
27							x
28	OpExp_Dist		4,333,019	1,947,957	552,233	1,832,829	x
29		TRUE	100.00%	44.96%	12.74%	42.30%	x
30							x
31	DistBill_RR-PF		8,104,056	4,274,574	1,496,079	2,333,402	x
32		TRUE	100.00%	52.75%	18.46%	28.79%	x
33							x
34	GRT_RevxT		6,433,118	3,376,804	1,181,864	1,874,450	x
35		TRUE	100.00%	52.49%	18.37%	29.14%	x
36							x

Funcl **Wellsboro Electric Company**
Funct **Embedded Cost of Service Study (ECOSS)**
Fac **FPFTY Ending December 31, 2026**
E-5B **Functionalization Factors**

0	Allocator Name	In Use	Total	Primary	Secondary	Billing	x
37	Labor		915,420	408,207	113,671	393,542	x
38		TRUE	100.00%	44.59%	12.42%	42.99%	x
39							x
40	D-Labor-Op		171,910	103,998	40,749	27,164	x
41		TRUE	100.00%	60.50%	23.70%	15.80%	x
42							x
43	D-Labor-Mnt		336,308	269,962	64,713	1,633	x
44		TRUE	100.00%	80.27%	19.24%	0.49%	x
45							x
46	Labor_Pt		2	1	0	1	x
47		TRUE	100.00%	53.06%	18.90%	28.05%	x
48							x
49	IntanPt		284,588	-	-	284,588	x
50		TRUE	100.00%	0.00%	0.00%	100.00%	x
51							x
52	TranPt		-	-	-	-	x
53		FALSE	0.00%	0.00%	0.00%	0.00%	x
54							x
55	OH_UG		26,142,155	18,719,219	7,422,936	-	x
56		TRUE	100.00%	71.61%	28.39%	0.00%	x
57							x
58	DistPt		34,485,748	22,890,353	10,034,297	1,561,098	x
59		TRUE	100.00%	66.38%	29.10%	4.53%	x
60							x
61	GenPtxL		117,901	52,575	14,640	50,686	x
62		TRUE	100.00%	44.59%	12.42%	42.99%	x
63							x
64	RateBase		25,857,280	15,778,363	6,311,053	3,767,865	x
65		TRUE	100.00%	61.02%	24.41%	14.57%	x
66							x
67	PreTax		35,348	288,998	171,564	(425,213)	x
68		TRUE	100.00%	817.57%	485.35%	-1202.93%	x
69							x
70	StaTax		460,561	288,998	171,564	-	x
71		TRUE	100.00%	62.75%	37.25%	0.00%	x
72							x
73	FedTax		546,595	342,983	203,612	-	x
74		TRUE	100.00%	62.75%	37.25%	0.00%	x
75							x
76	Plant		44,382,268	27,303,444	11,263,179	5,815,645	x
77		TRUE	100.00%	61.52%	25.38%	13.10%	x

Class **Wellsboro Electric Company**
Class **Embedded Cost of Service Study (ECOSS)**
Fac **FPFTY Ending December 31, 2026**
E-5C **Classification Factors**

0	Allocator Name	In Use	Total	Demand	Commodity	Customer
1	None		0			
2		FALSE	0.00%	0.00%	0.00%	0.00%
3						
4	Demand		1	1		
5		TRUE	100.00%	100.00%	0.00%	0.00%
6						
7	Commodity		1		1	
8		TRUE	100.00%	0.00%	100.00%	0.00%
9						
10	Customer		1			1
11		TRUE	100.00%	0.00%	0.00%	100.00%
12						
13	PTF-Sec-Z		100.00%	36.96%	0.00%	63.04%
14		TRUE	100.00%	36.96%	0.00%	63.04%
15						
16	OH-Sec-Z		100.00%	43.97%	0.00%	56.03%
17		TRUE	100.00%	43.97%	0.00%	56.03%
18						
19	UG-Sec-Z		100.00%	63.71%	0.00%	36.29%
20		TRUE	100.00%	63.71%	0.00%	36.29%
21						
22	Trans-Min		100.00%	22.45%	0.00%	77.55%
23		TRUE	100.00%	22.45%	0.00%	77.55%
24						
25	Sec_RB		6,311,053	1,862,647	-	4,448,406
26		TRUE	100.00%	29.51%	0.00%	70.49%
27						
28	Sec-Pt		11,263,179	3,083,725	-	8,179,454
29		TRUE	100.00%	27.38%	0.00%	72.62%
30						
31	Sec-RB		6,311,053	1,862,647	-	4,448,406
32		TRUE	100.00%	29.51%	0.00%	70.49%
33						
34	Sec-OH_UG		26,898,673	18,719,219	-	8,179,454
35		TRUE	100.00%	69.59%	0.00%	30.41%
36						

Clas: **Wellsboro Electric Company**
Clas: **Embedded Cost of Service Study (ECOSS)**
Fac **FPFTY Ending December 31, 2026**
E-5C **Classification Factors**

0	Allocator Name	In Use	Total	Demand	Commodity	Customer
37	Sec-GenPt		1,228,882	630,785	-	598,097
38		TRUE	100.00%	51.33%	0.00%	48.67%
39						
40	Sec-OpExp		552,233	259,415	-	292,817
41		TRUE	100.00%	46.98%	0.00%	53.02%
42						
43	Sec-DiPt		10,034,297	2,452,940	-	7,581,357
44		TRUE	100.00%	24.45%	0.00%	75.55%
45						
46	Sec-Lab		113,671	58,347	-	55,323
47		TRUE	100.00%	51.33%	0.00%	48.67%
48						
49	Sec-Rev		1,181,864	418,150	-	763,714
50		TRUE	100.00%	35.38%	0.00%	64.62%
51						
52	Sec-LabPt		200.00%	78.71%	0.00%	121.29%
53		TRUE	100.00%	39.35%	0.00%	60.65%
54						
55	Sec-PreTax		171,564	27,300	-	144,264
56		TRUE	100.00%	15.91%	0.00%	84.09%
57						
58	Sec-StaTax		171,564	27,300	-	144,264
59		TRUE	100.00%	15.91%	0.00%	84.09%
60						
61	Sec-FedTax		203,612	32,400	-	171,213
62		TRUE	100.00%	15.91%	0.00%	84.09%
63						
64	Sec-RetRRPF		1,496,079	529,321	-	966,758
65		TRUE	100.00%	35.38%	0.00%	64.62%
66						

AllocFct **Wellsboro Electric Company**
Class Al **Embedded Cost of Service Study (ECOSS)**
Fac **FPFTY Ending December 31, 2026**
E-5D **Class Allocation Factors**

0	Allocator Name	In Use	Total	RS	RSAE	NRS	NRH	CS	CSH	IS	MSL	POL	EX
1	None		-										
2		FALSE	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
3													
4	MWh-Meter		105,861,774	44,812,773	397,781	4,732,166	6,256	29,056,715	7,216	26,746,293	-	-	102,572
5		TRUE	100.00%	42.33%	0.38%	4.47%	0.01%	27.45%	0.01%	25.27%	0.00%	0.00%	0.10%
6													
7	NCP-Prim		20036	9,206	123	846	9	5,356	18	4,411	13	41	12
8		TRUE	100.00%	45.95%	0.61%	4.22%	0.04%	26.73%	0.09%	22.01%	0.07%	0.21%	0.06%
9													
10	NCP-Sec		15,613	9,206	123	846	9	5,356	18	-	13	41	-
11		TRUE	100.00%	58.96%	0.79%	5.42%	0.06%	34.31%	0.12%	0.00%	0.09%	0.27%	0.00%
12													
13	NCP-Ltr		3,689	-	-	-	4	3,616	14	-	13	41	-
14		TRUE	100.00%	0.00%	0.00%	0.00%	0.12%	98.02%	0.37%	0.00%	0.36%	1.12%	0.00%
15													
16	AVG-CUST		6,538	5,159	29	938	1	392	1	13	-	-	4
17		TRUE	100.00%	78.91%	0.45%	14.35%	0.02%	6.00%	0.02%	0.20%	0.00%	0.00%	0.06%
18													
19	Services_Cost		5,345,508	3,952,747	22,346	718,786	766	627,903	1,602	21,357	-	-	-
20		TRUE	100.00%	73.95%	0.42%	13.45%	0.01%	11.75%	0.03%	0.40%	0.00%	0.00%	0.00%
21													
22	Avg-Cust-Sec		6,525	5,159	29	938	1	392	1		-	-	4
23		TRUE	100.00%	79.07%	0.45%	14.38%	0.02%	6.01%	0.02%	0.00%	0.00%	0.00%	0.06%
24													
25	Meters		6,538	5,159	29	938	1	392	1	13	-	-	4
26		TRUE	100.00%	78.91%	0.45%	14.35%	0.02%	6.00%	0.02%	0.20%	0.00%	0.00%	0.06%
27													
28	Meter_Cost		3,086,287	1,857,300	10,500	337,740	360	671,990	1,714	158,987	-	-	47,696
29		TRUE	100.00%	60.18%	0.34%	10.94%	0.01%	21.77%	0.06%	5.15%	0.00%	0.00%	1.55%
30													

AllocFct **Wellsboro Electric Company**
Class Al **Embedded Cost of Service Study (ECOSS)**
Fac **FPFTY Ending December 31, 2026**
E-5D **Class Allocation Factors**

0	Allocator Name	In Use	Total	RS	RSAE	NRS	NRH	CS	CSH	IS	MSL	POL	EX
31	Dist_Rev		6,401,996	3,370,741	24,594	498,637	676	1,522,475	1,028	880,020	13,496	81,371	8,957
32		TRUE	100.00%	52.65%	0.38%	7.79%	0.01%	23.78%	0.02%	13.75%	0.21%	1.27%	0.14%
33													
34	Total_Rev		13,072,503	6,981,957	53,402	834,441	1,630	3,223,216	1,585	1,857,933	19,106	81,371	17,863
35		TRUE	100.00%	53.41%	0.41%	6.38%	0.01%	24.66%	0.01%	14.21%	0.15%	0.62%	0.14%
36													
37	Supp_Rev		6,670,507	3,611,216	28,807	335,804	954	1,700,741	557	977,913	5,609	-	8,907
38		TRUE	100.00%	54.14%	0.43%	5.03%	0.01%	25.50%	0.01%	14.66%	0.08%	0.00%	0.13%
39													
40	CustDeposits		121,200	69,887	513	6,802	18	27,394	14	15,694	-	721	158
41		TRUE	100.00%	57.66%	0.42%	5.61%	0.01%	22.60%	0.01%	12.95%	0.00%	0.59%	0.13%
42													
43	Write-Offs		1	1	0	0	0	0	0	0	-	0	0
44		TRUE	100.00%	86.99%	0.64%	1.66%	0.00%	6.67%	0.00%	3.82%	0.00%	0.18%	0.04%
45													
46	StLgt-Lamps		2	-	-	-	-	-	-	-	1	1	-
47		TRUE	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	50.00%	50.00%	0.00%
48													
49	PriD-Lab		408,207	187,563	2,509	17,230	179	109,124	371	89,862	274	844	252
50		TRUE	100.00%	45.95%	0.61%	4.22%	0.04%	26.73%	0.09%	22.01%	0.07%	0.21%	0.06%
51													
52	PriD-DxPt		22,890,353	10,517,637	140,713	966,155	10,050	6,119,146	20,807	5,039,033	15,374	47,324	14,115
53		TRUE	100.00%	45.95%	0.61%	4.22%	0.04%	26.73%	0.09%	22.01%	0.07%	0.21%	0.06%
54													
55	PriD-Pt		27,303,444	12,545,359	167,841	1,152,422	11,987	7,298,872	24,818	6,010,522	18,338	56,447	16,837
56		TRUE	100.00%	45.95%	0.61%	4.22%	0.04%	26.73%	0.09%	22.01%	0.07%	0.21%	0.06%
57													
58	PriD-LabPt		200.00%	91.90%	1.23%	8.44%	0.09%	53.46%	0.18%	44.03%	0.13%	0.41%	0.12%
59		TRUE	100.00%	45.95%	0.61%	4.22%	0.04%	26.73%	0.09%	22.01%	0.07%	0.21%	0.06%
60													
61	PriD-OpExp		1,947,957	895,045	11,975	82,219	855	520,736	1,771	428,819	1,308	4,027	1,201
62		TRUE	100.00%	45.95%	0.61%	4.22%	0.04%	26.73%	0.09%	22.01%	0.07%	0.21%	0.06%
63													

AllocFct **Wellsboro Electric Company**
Class Al **Embedded Cost of Service Study (ECOSS)**
Fac **FPFTY Ending December 31, 2026**
E-5D **Class Allocation Factors**

0	Allocator Name	In Use	Total	RS	RSAE	NRS	NRH	CS	CSH	IS	MSL	POL	EX
64	SecD-Lab		58,347	33,912	454	3,115	33	20,548	70	-	53	162	-
65		TRUE	100.00%	58.12%	0.78%	5.34%	0.06%	35.22%	0.12%	0.00%	0.09%	0.28%	0.00%
66													
67	SecD-DxPt		2,452,940	1,000,820	13,390	91,936	1,849	1,322,937	4,801	-	4,219	12,988	-
68		TRUE	100.00%	40.80%	0.55%	3.75%	0.08%	53.93%	0.20%	0.00%	0.17%	0.53%	0.00%
69													
70	SecD-Pt		3,083,725	1,367,443	18,295	125,614	2,210	1,545,077	5,560	-	4,788	14,739	-
71		TRUE	100.00%	44.34%	0.59%	4.07%	0.07%	50.10%	0.18%	0.00%	0.16%	0.48%	0.00%
72													
73	SecD-UG		282,151	166,369	2,226	15,283	159	96,793	329	-	243	749	-
74		TRUE	100.00%	58.96%	0.79%	5.42%	0.06%	34.31%	0.12%	0.00%	0.09%	0.27%	0.00%
75													
76	SecD-LabPt		200.00%	102.47%	1.37%	9.41%	0.13%	85.32%	0.30%	0.00%	0.25%	0.76%	0.00%
77		TRUE	100.00%	51.23%	0.69%	4.71%	0.06%	42.66%	0.15%	0.00%	0.12%	0.38%	0.00%
78													
79	SecD-OpExp		259,415	147,756	1,977	13,573	152	94,620	325	-	248	764	-
80		TRUE	100.00%	56.96%	0.76%	5.23%	0.06%	36.47%	0.13%	0.00%	0.10%	0.29%	0.00%
81													
82	SecC-Lab		55,323	42,806	242	7,784	8	3,407	9	10	512	512	32
83		TRUE	100.00%	77.37%	0.44%	14.07%	0.01%	6.16%	0.02%	0.02%	0.93%	0.93%	0.06%
84													
85	SecC-DxPt		7,581,357	5,768,306	32,610	1,048,935	1,118	590,629	1,507	9,933	62,636	62,636	3,047
86		TRUE	100.00%	76.09%	0.43%	13.84%	0.01%	7.79%	0.02%	0.13%	0.83%	0.83%	0.04%
87													
88	SecC-Pt		8,179,454	6,231,082	35,227	1,133,089	1,208	627,464	1,601	10,042	68,176	68,176	3,390
89		TRUE	100.00%	76.18%	0.43%	13.85%	0.01%	7.67%	0.02%	0.12%	0.83%	0.83%	0.04%
90													
91	SecC-LTr		2,609,971	2,063,802	11,667	375,291	400	156,810	400	-	-	-	1,600
92		TRUE	100.00%	79.07%	0.45%	14.38%	0.02%	6.01%	0.02%	0.00%	0.00%	0.00%	0.06%
93													

AllocFct **Wellsboro Electric Company**
Class Al **Embedded Cost of Service Study (ECOSS)**
Fac **FPFTY Ending December 31, 2026**
E-5D **Class Allocation Factors**

0	Allocator Name	In Use	Total	RS	RSAE	NRS	NRH	CS	CSH	IS	MSL	POL	EX
94	SecC-LabPt		2	2	0	0	0	0	0	0	0	0	0
95		TRUE	100.00%	76.78%	0.43%	13.96%	0.01%	6.91%	0.02%	0.07%	0.88%	0.88%	0.05%
96													
97	SecC-OpExp		292,817	227,145	1,284	41,305	44	18,782	48	99	1,974	1,974	162
98		TRUE	100.00%	77.57%	0.44%	14.11%	0.02%	6.41%	0.02%	0.03%	0.67%	0.67%	0.06%
99													
100	Bill-Lab		393,542	303,276	1,715	55,149	59	29,726	76	2,725	-	-	817
101		TRUE	100.00%	77.06%	0.44%	14.01%	0.01%	7.55%	0.02%	0.69%	0.00%	0.00%	0.21%
102													
103	Bill-DxLab		29,004	17,719	100	3,222	3	6,092	16	1,424	-	-	427
104		TRUE	100.00%	61.09%	0.35%	11.11%	0.01%	21.00%	0.05%	4.91%	0.00%	0.00%	1.47%
105													
106	Bill-DxPt		1,561,098	1,036,797	5,861	188,536	201	257,921	658	54,710	-	-	16,413
107		TRUE	100.00%	66.41%	0.38%	12.08%	0.01%	16.52%	0.04%	3.50%	0.00%	0.00%	1.05%
108													
109	Bill-Pt		5,815,645	4,315,485	24,397	784,748	836	579,284	1,478	84,167	-	-	25,250
110		TRUE	100.00%	74.20%	0.42%	13.49%	0.01%	9.96%	0.03%	1.45%	0.00%	0.00%	0.43%
111													
112	Bill-LabPt		200.00%	151.27%	0.86%	27.51%	0.03%	17.51%	0.04%	2.14%	0.00%	0.00%	0.64%
113		TRUE	100.00%	75.63%	0.43%	13.75%	0.01%	8.76%	0.02%	1.07%	0.00%	0.00%	0.32%
114													
115	Bill-OpExp		1,832,829	1,389,229	8,255	245,508	306	153,788	417	30,854	663	855	2,954
116		TRUE	100.00%	75.80%	0.45%	13.40%	0.02%	8.39%	0.02%	1.68%	0.04%	0.05%	0.16%
117													
118	PreTax		35,348	(418,467)	(9,300)	(43,804)	(1,307)	282,002	(2,807)	156,475	5,900	64,957	1,699
119		TRUE	100.00%	(1183.8%)	(26.3%)	(123.9%)	(3.7%)	797.8%	(7.9%)	442.7%	16.7%	183.8%	4.8%
120													
121	PreStaTax		44,666,856	24,683,945	247,029	3,236,711	16,285	10,067,760	33,500	6,105,310	91,302	139,363	45,651
122		TRUE	100.00%	55.26%	0.55%	7.25%	0.04%	22.54%	0.07%	13.67%	0.20%	0.31%	0.10%
123													
124	PreFedTax		44,666,856	24,683,945	247,029	3,236,711	16,285	10,067,760	33,500	6,105,310	91,302	139,363	45,651
125		TRUE	100.00%	55.26%	0.55%	7.25%	0.04%	22.54%	0.07%	13.67%	0.20%	0.31%	0.10%
126													
127	Plant		44,666,856	24,683,945	247,029	3,236,711	16,285	10,067,760	33,500	6,105,310	91,302	139,363	45,651
128		TRUE	100.00%	55.26%	0.55%	7.25%	0.04%	22.54%	0.07%	13.67%	0.20%	0.31%	0.10%
129													
130	RateBase		25,857,280	14,330,403	143,611	1,883,819	9,415	5,706,466	19,138	3,491,939	111,717	138,165	22,606
131		TRUE	100.00%	55.42%	0.56%	7.29%	0.04%	22.07%	0.07%	13.50%	0.43%	0.53%	0.09%
132													

WP

Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026
INDEX TO WORKPAPERS

Line		DESCRIPTION	PERIOD
1	WP	Index To Workpapers	
2	WP_B1	Monthly Billing Units, Rates And Revenue	HY 2024- Present Rates
3	WP_B2	Historic Sales and Revenue	Historic Sales and Revenue
4	WP_B3	Historic Billing Units	Historic Billing Units
5	WP_B4	Sales Recap	Period Ending December 31, 2024
6	WP_B5	Total Operating Revenues	January 1, 2024 to December 31, 2024
7	WP_C1	Expenses By Account and By Type	Year 2013, HY 2024, FTY 2025 and FPFTY 2026
8	WP_C2	Expenses By Account	Year 2013, HY 2024, FTY 2025 and FPFTY 2026
9	WP_C3	Accumulated Deferred Income Taxes	Years 2024 through 2026

Wellsboro Electric Company
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		Sch. 1- RS	Sch. 2- RSAE	Sch. 3- NRS	Sch. 3- NRH	Sch. 4- CS	Sch. 4- CSH	Sch. 5- IS	Sch. 6- MSL	Sch. 7- POL	Sch. 8- EU	Total
1												
2		**BILLING UNITS**										
3		**kWh Sales HY 2024**										
4	Jan-24	4,000,928	38,314	373,296	801	2,365,819	440	2,029,329	5,519	16,856	8,415	8,839,717
5	Feb-24	3,891,863	40,795	374,369	1,548	2,342,175	520	1,984,942	5,389	16,856	8,654	8,667,111
6	Mar-24	3,636,509	39,216	379,223	2,020	2,352,274	520	1,864,451	5,389	16,856	7,983	8,304,441
7	Apr-24	3,344,243	33,184	348,420	1,533	2,135,105	480	2,066,009	5,389	16,856	8,201	7,959,420
8	May-24	2,881,391	24,071	294,649	434	1,901,201	400	2,050,885	5,389	16,856	7,694	7,182,970
9	Jun-24	2,990,307	18,248	301,734	549	2,105,258	480	2,339,790	5,389	16,856	8,191	7,786,802
10	Jul-24	3,759,704	19,564	337,055	750	2,285,778	760	2,215,131	5,389	16,856	8,790	8,649,777
11	Aug-24	3,810,940	19,449	332,303	748	2,324,893	1,000	2,153,540	5,389	16,856	8,426	8,673,544
12	Sep-24	3,481,321	19,264	316,634	725	2,269,507	680	1,928,775	5,389	16,856	7,922	8,047,073
13	Oct-24	2,836,841	16,643	278,416	680	2,002,556	520	1,911,524	5,389	16,856	7,068	7,076,493
14	Nov-24	3,213,097	25,133	301,310	591	2,131,623	280	2,034,009	5,389	16,856	9,268	7,737,556
15	Dec-24	3,601,220	31,854	321,421	447	2,073,041	400	2,031,795	5,389	16,856	11,960	8,094,383
16		41,448,363	325,735	3,958,829	10,826	26,289,234	6,480	24,610,180	64,798	202,270	102,572	97,019,287
17	Adj for POL	41,448,363	325,735	3,958,829	10,826	26,289,234	6,480	24,610,180	64,798	202,270	102,572	97,019,287
18		**GSSR Sales HY 2024**										
19	Jan-24	4,000,928	38,314	373,296	801	2,365,819	440	1,679,575	5,519			8,464,692
20	Feb-24	3,891,863	40,795	374,369	1,548	2,342,175	520	1,541,833	5,389			8,198,492
21	Mar-24	3,636,509	39,216	379,223	2,020	2,352,274	520	1,430,263	5,389			7,845,414
22	Apr-24	3,344,243	33,184	348,420	1,533	2,135,105	480	1,628,350	5,389			7,496,704
23	May-24	2,881,391	24,071	294,649	434	1,901,201	400	1,588,305	5,389			6,695,840
24	Jun-24	2,990,307	18,248	301,734	549	2,105,258	480	1,852,581	5,389			7,274,546
25	Jul-24	3,759,704	19,564	337,055	750	2,285,778	760	1,742,150	5,389			8,151,150
26	Aug-24	3,810,940	19,449	332,303	748	2,324,893	1,000	1,670,147	5,389			8,164,869
27	Sep-24	3,481,321	19,264	316,634	725	2,269,507	680	1,478,126	5,389			7,571,646
28	Oct-24	2,836,841	16,643	278,416	680	2,002,556	520	1,501,093	5,389			6,642,138
29	Nov-24	3,213,097	25,133	301,310	591	2,131,623	280	1,586,405	5,389			7,263,828
30	Dec-24	3,601,220	31,854	321,421	447	2,073,041	400	1,661,555	5,389			7,695,327
31		41,448,363	325,735	3,958,829	10,826	26,289,234	6,480	19,360,383	64,798	0	0	91,464,648

Wellsboro Electric Company
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Full Month Customers HY 2024												
Jan-24		5,124	31	901	2	379	1	13			4	6,455
Feb-24		5,122	31	901	2	381	1	13			4	6,455
Mar-24		5,123	31	903	2	381	1	13			4	6,458
Apr-24		5,125	30	904	1	382	1	13			4	6,460
May-24		5,127	30	910	1	379	1	13			4	6,465
Jun-24		5,131	30	909	1	379	1	13			4	6,468
Jul-24		5,138	30	911	1	380	1	13			4	6,478
Aug-24		5,136	29	912	1	380	1	13			4	6,476
Sep-24		5,135	29	911	1	381	1	13			4	6,475
Oct-24		5,139	29	910	1	382	1	13			4	6,479
Nov-24		5,129	29	910	1	384	1	13			4	6,471
Dec-24		5,127	29	911	1	385	1	13			4	6,471
Annual Bills		61,556	358	10,893	15	4,573	12	156	0	0	48	77,611
Average Monthly B		5,130	30	908	1	381	1	13	0	0	4	6,468
Monthly Billing Units- Public Lighting and Street Lighting HY 2024												
Rate 1							Mercury	7000 lumens	0	0		0
Rate 2							Mercury	20000 lumens	1	1		2
Rate 3							Sodium	9500 lumens	0	0		0
Rate 4							Sodium	16000 lumens	0	0		0
							LED	50 OH	148	425		573
							LED	50 UG	0	0		0
							LED	50 UG Col	0	0		0
							LED	70 OH	109	364		473
							LED	70 UG	0	0		0
							LED	140 OH	0	2		2
							LED	140 UG	0	0		0
									258	792		1,050

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62							**RATES AND CHARGES**						
63							**Tariff Rates**						
64	Customer Ch	Jan-J	$12.00	$12.00	$12.22	$12.22	$32.03	$45.81	$85.00				
65		Jul-S	$12.00	$12.00	$12.22	$12.22	$32.03	$45.81	$85.00				
66		Oct-I	$12.00	$12.00	$12.22	$12.22	$32.03	$45.81	$85.00				
67													
68	Energy Block	Jan-J	$0.058640	$0.051270	$0.076300	$0.084690	$0.022680	$0.066280	$0.020780			$0.087320	
69		Jul-S	$0.058640	$0.051270	$0.076300	$0.084690	$0.022680	$0.066280	$0.020780			$0.087320	
70		Oct-I	$0.058640	$0.051270	$0.076300	$0.084690	$0.022680	$0.066280	$0.020780			$0.087320	
71													
72	Energy Block	Jan-Jun							$0.001300				
73		Jul-Sep							$0.001300				
74		Oct-Dec							$0.001300				
75													
76	Block 1 Demand								100				
77	Demand Bloc	Jan-Jun					$6.60		$10.00				
78		Jul-Sep					$6.60		$10.00				
79		Oct-Dec					$6.60		$10.00				
80													
81	E-Factor Mar-Jun												
82	E-Factor Jul-Dec												
83	Block 1 Energy = Demand X								130				
84													
85	CCSC Charg	Jan-J	$0.000000	$0.000000	$0.000000	$0.000000	$0.000000	$0.000000	$0.000000	$0.000000	$0.000000	$0.000000	
86		Jul-D	$0.000000	$0.000000	$0.000000	$0.000000	$0.000000	$0.000000	$0.000000	$0.000000	$0.000000	$0.000000	
87	STAS Rate		0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%		
88													

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		Sch. 1- RS	Sch. 2- RSAE	Sch. 3- NRS	Sch. 3- NRH	Sch. 4- CS	Sch. 4- CSH	Sch. 5- IS	Sch. 6- MSL	Sch. 7- POL	Sch. 8- EU	Total
89		**COMPUTATION OF REVENUE**										
90		**Customer Charge Revenue- Full Month Customers**										
91	Jan-24	$61,488	$372	$11,010	$24	$12,139	$46	$1,105	$0	$0	$0	$86,185
92	Feb-24	61,464	372	11,010	24	12,203	46	1,105				86,225
93	Mar-24	61,476	372	11,035	24	12,203	46	1,105				86,261
94	Apr-24	61,500	360	11,047	12	12,235	46	1,105				86,305
95	May-24	61,524	360	11,120	12	12,139	46	1,105				86,307
96	Jun-24	61,572	360	11,108	12	12,139	46	1,105				86,342
97	Jul-24	61,656	360	11,132	12	12,171	46	1,105				86,483
98	Aug-24	61,632	348	11,145	12	12,171	46	1,105				86,459
99	Sep-24	61,620	348	11,132	12	12,203	46	1,105				86,467
100	Oct-24	61,668	348	11,120	12	12,235	46	1,105				86,535
101	Nov-24	61,548	348	11,120	12	12,300	46	1,105				86,479
102	Dec-24	61,524	348	11,132	12	12,332	46	1,105				86,499
103		$738,672	$4,296	$133,112	$183	$146,473	$550	$13,260	$0	$0	$0	$1,036,547
104												
105		**Distribution kWh Revenue**										
106	Jan-24	$234,614	$1,964	$28,482	$68	$53,657	$29	$14,368	$1,131	$6,806	$735	$341,855
107	Feb-24	228,219	2,092	28,564	131	53,121	34	14,589	1,131	6,806	756	335,442
108	Mar-24	213,245	2,011	28,935	171	53,350	34	14,464	1,131	6,806	697	320,843
109	Apr-24	196,106	1,701	26,584	130	48,424	32	14,848	1,131	6,806	716	296,479
110	May-24	168,965	1,234	22,482	37	43,119	27	15,261	1,131	6,806	672	259,733
111	Jun-24	175,352	936	23,022	46	47,747	32	16,478	1,131	6,806	715	272,265
112	Jul-24	220,469	1,003	25,717	64	51,841	50	16,575	1,131	6,806	768	324,424
113	Aug-24	223,474	997	25,355	63	52,729	66	16,511	1,131	6,806	736	327,867
114	Sep-24	204,145	988	24,159	61	51,472	45	16,000	1,131	6,806	692	305,499
115	Oct-24	166,352	853	21,243	58	45,418	34	15,501	1,131	6,806	617	258,014
116	Nov-24	188,416	1,289	22,990	50	48,345	19	14,658	1,131	6,806	809	284,513
117	Dec-24	211,176	1,633	24,524	38	47,017	27	14,360	1,131	6,806	1,044	307,755
118		$2,430,532	$16,700	$302,059	$917	$596,240	$429	$183,612	$13,576	$81,667	$8,957	$3,634,689
119												
120		**Distribution Demand Revenue**										
121	Jan-24					$52,012		$46,319				$98,331
122	Feb-24					53,663		47,420				101,083
123	Mar-24					51,176		47,543				98,719
124	Apr-24					51,107		48,025				99,132
125	May-24					52,645		49,736				102,380
126	Jun-24					55,868		53,058				108,925
127	Jul-24					59,302		54,079				113,381
128	Aug-24					59,833		54,144				113,977
129	Sep-24					58,429		53,280				111,709
130	Oct-24					56,828		51,398				108,226
131	Nov-24					55,505		47,440				102,946
132	Dec-24					55,023		46,273				101,296
133		$0	$0	$0	$0	$661,390	$0	$598,716	$0	$0	$0	$1,260,106
134				*$0*		*$671,699*		*$598,716*				*$1,270,414*
135		**STAS Revenue- Distribution**										

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136	STAS Revenue											
137		(697)	(5)	(72)	(0)	(319)	(0)	(175)	(2)		0	(1,270)
138							**GSSR Revenue**					
139	GSSR Revenue	3,611,216	28,807	335,804	954	1,700,741	557	977,913	5,609		8,907	6,670,507
140												
141												
142							**Total Revenue**					
143	Revenue excluding	6,780,420	49,804	770,975	2,054	3,104,844	1,536	1,773,500	19,185	81,667	17,863	12,601,848
144	POL	53,230	413	14,909		13,115				(81,667)		0
145												
146	Total Revenue	6,833,650	50,217	785,884	2,054	3,117,958	1,536	1,773,500	19,185	0	17,863	12,601,848
147		6,834,759	50,237	784,194	2,066	3,125,447	1,536	1,771,907	19,067		17,863	12,607,075
148												12,607,075

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149		**BILLING UNITS- DETAIL**										
150		**Block 1 kWh Sales HY 2024**										
151	Jan-24	4,000,928	38,314	373,296	801	2,365,819	440	602,152	5,519	16,856	8,415	7,412,540
152	Feb-24	3,891,863	40,795	374,369	1,548	2,342,175	520	616,456	5,389	16,856	8,654	7,298,625
153	Mar-24	3,636,509	39,216	379,223	2,020	2,352,274	520	618,064	5,389	16,856	7,983	7,058,054
154	Apr-24	3,344,243	33,184	348,420	1,533	2,135,105	480	624,328	5,389	16,856	8,201	6,517,739
155	May-24	2,881,391	24,071	294,649	434	1,901,201	400	646,564	5,389	16,856	7,694	5,778,649
156	Jun-24	2,990,307	18,248	301,734	549	2,105,258	480	689,748	5,389	16,856	8,191	6,136,760
157	Jul-24	3,759,704	19,564	337,055	750	2,285,778	760	703,028	5,389	16,856	8,790	7,137,674
158	Aug-24	3,810,940	19,449	332,303	748	2,324,893	1,000	703,871	5,389	16,856	8,426	7,223,875
159	Sep-24	3,481,321	19,264	316,634	725	2,269,507	680	692,644	5,389	16,856	7,922	6,810,942
160	Oct-24	2,836,841	16,643	278,416	680	2,002,556	520	668,177	5,389	16,856	7,068	5,833,146
166	Nov-24	3,213,097	25,133	301,310	591	2,131,623	280	616,724	5,389	16,856	9,268	6,320,271
167	Dec-24	3,601,220	31,854	321,421	447	2,073,041	400	601,550	5,389	16,856	11,960	6,664,138
168		41,448,363	325,735	3,958,829	10,826	26,289,234	6,480	7,783,305	64,798	202,270	102,572	80,192,412
169												
170		**Block 2 kWh Sales HY 2024**										
171	Jan-24							1,427,177				1,427,177
172	Feb-24							1,368,486				1,368,486
173	Mar-24							1,246,387				1,246,387
174	Apr-24							1,441,681				1,441,681
175	May-24							1,404,321				1,404,321
176	Jun-24							1,650,043				1,650,043
177	Jul-24							1,512,103				1,512,103
178	Aug-24							1,449,669				1,449,669
179	Sep-24							1,236,131				1,236,131
180	Oct-24							1,243,347				1,243,347
181	Nov-24							1,417,285				1,417,285
182	Dec-24							1,430,245				1,430,245
183		0	0	0	0	0	0	16,826,875	0	0	0	16,826,875
184												97,019,287
185		**Block 1 kW Demand HY 2024**										
186	Jan-24				From Demand	7,881		4,632	From Demand file			12,513
187	Feb-24					8,131		4,742				12,873
188	Mar-24					7,754		4,754				12,508
189	Apr-24					7,744		4,803				12,546
190	May-24					7,976		4,974				12,950
191	Jun-24					8,465		5,306				13,771
192	Jul-24					8,985		5,408				14,393
193	Aug-24					9,066		5,414				14,480
194	Sep-24					8,853		5,328				14,181
195	Oct-24					8,610		5,140				13,750
196	Nov-24					8,410		4,744				13,154
197	Dec-24					8,337		4,627				12,964
198		0	0	0	0	100,211	0	59,872	0	0	0	160,082
199												

Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026
Monthly Billing Units, Rates And Revenue
HY 2024- Present Rates

	Sch. 1- RS	Sch. 2- RSAE	Sch. 3- NRS	Sch. 3- NRH	Sch. 4- CS	Sch. 4- CSH	Sch. 5- IS	Sch. 6- MSL	Sch. 7- POL	Sch. 8- EU	Total
			RCL								
	Total kWh	RS	NRS Tot kWh		Total CS kWh- TCL		Total IS kWh	TCP kWh	RCP kWh		
Jan-24	4,000,928	4,011,825	376,362		2,368,626		2,029,329	698,575	1,330,754		
Feb-24	3,891,863	3,902,760	377,435		2,344,982		1,984,942	695,233	1,289,709		
Mar-24	3,636,509	3,647,406	382,289		2,355,081		1,864,451	664,603	1,199,848		
Apr-24	3,344,243	3,355,140	351,486		2,137,912		2,066,009	713,890	1,352,119		
May-24	2,881,391	2,892,288	297,715		1,904,008		2,050,885	735,645	1,315,240		
Jun-24	2,990,307	3,001,204	304,800		2,108,065		2,339,790	863,541	1,476,249		
Jul-24	3,759,704	3,770,601	340,121		2,288,585		2,215,131	939,350	1,275,781		
Aug-24	3,810,940	3,821,837	335,369		2,327,700		2,153,540	894,347	1,259,193		
Sep-24	3,481,321	3,492,218	319,700		2,272,314		1,928,775	772,826	1,155,949		
Oct-24	2,836,841	2,847,738	281,482		2,005,363		1,911,524	719,113	1,192,411		
Nov-24	3,213,097	3,223,994	304,376		2,134,430		2,034,009	704,465	1,329,544		
Dec-24	3,601,220	3,612,117	324,487		2,075,848		2,031,795	639,875	1,391,920		
	41,448,363	41,579,128	3,995,622		26,322,914		24,610,180	9,041,463	15,568,717		

	Total kWh				RSAE
	RL	RFL	TL	TOTAL	
Jan-24	2,878,005	109,229	1,024,591	4,011,825	38,400
Feb-24	2,775,040	109,210	1,018,510	3,902,760	40,881
Mar-24	2,563,062	99,030	985,314	3,647,406	39,302
Apr-24	2,408,971	93,758	852,411	3,355,140	33,270
May-24	2,060,811	84,343	747,134	2,892,288	24,157
Jun-24	2,181,632	83,679	735,893	3,001,204	18,334
Jul-24	2,789,297	98,533	882,771	3,770,601	19,650
Aug-24	2,687,911	96,275	1,037,651	3,821,837	19,535
Sep-24	2,459,982	87,004	945,232	3,492,218	19,350
Oct-24	2,048,006	77,048	722,684	2,847,738	16,729
Nov-24	2,339,080	86,582	798,332	3,223,994	25,219
Dec-24	2,668,152	89,901	854,064	3,612,117	31,940
	29,859,949	1,114,592	10,604,587	41,579,128	326,767

MSL

	ML Monthly Lamps						
	MV175	SV100	LED50 OH	LED70 OH	Total		
Lamps			148.00	108.92	257		
Monthly kWh / Lamp			18	25			
Monthly kWh			2,664	2,723	5,387	64,643	Annual
Monthly Charge / Lamp	6.09	7.45	4.12	4.69			
Distribution Revenue	0	0	610	511	1,121	13,447	Annual

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Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026
Monthly Billing Units, Rates And Revenue
Historic Sales and Revenue

1	**KWh**			Actual	Actual	Actual	Actual	Actual
2	Rate Class			2020	2021	2022	2023	2024
3	Residential	RS	TL	10,994,242	11,252,118	11,110,832	10,539,016	10,604,587
4	Residential	RS	RL	31,324,751	31,733,114	31,136,489	29,627,494	29,859,949
5	Residential	RS	RFL	1,482,991	1,282,060	1,213,436	1,142,592	1,114,592
6	Residential	RSAE	RSAE	448,709	428,550	407,590	360,384	326,767
7	Commercial	CS	TCL	26,250,627	26,911,703	27,823,411	26,651,913	26,322,914
8	Commercial	NRS	RCL	4,214,185	4,344,682	4,256,960	4,164,254	3,995,622
9	Commercial	NRH	3H	10,845	12,069	11,931	10,394	10,826
10	Commercial	CSH	4H	7,720	7,760	7,520	6,600	6,480
11	Industrial	IS	TCP	9,224,524	9,187,198	8,897,268	8,803,511	9,041,463
12	Industrial	IS	RCP	18,109,080	18,428,280	16,431,158	15,989,514	15,568,717
13	Public St. Lighting	MSL	MSL	203,547	119,398	71,086	68,077	64,798
14	Sales for Resale	EU	EU	86,672	89,564	90,549	94,767	102,572
15								
16	Adjusted Sales			102,357,893	103,796,496	101,458,230	97,458,516	97,019,287
17								
18	Schedule 1- RS			43,801,984	44,267,292	43,460,757	41,309,102	41,579,128
19	Schedule 2- RSAE			448,709	428,550	407,590	360,384	326,767
20	Schedule 3- NRS			4,214,185	4,344,682	4,256,960	4,164,254	3,995,622
21	Schedule 3- NRH			10,845	12,069	11,931	10,394	10,826
22	Schedule 4- CS			26,250,627	26,911,703	27,823,411	26,651,913	26,322,914
23	Schedule 4- CSH			7,720	7,760	7,520	6,600	6,480
24	Schedule 5- IS			27,333,604	27,615,478	25,328,426	24,793,025	24,610,180
25	Schedule 6- MSL			203,547	119,398	71,086	68,077	64,798
26	Schedule 7- POL							
27	Schedule 8- Resale			86,672	89,564	90,549	94,767	102,572
28				102,357,893	103,796,496	101,458,230	97,458,516	97,019,287
29	**Adjusted for POL**							

WP_B2

Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026
Monthly Billing Units, Rates And Revenue
Historic Sales and Revenue

	KWh	Actual	Actual	Actual	Actual	Actual
	Rate Class	2020	2021	2022	2023	2024
30	Schedule 1- RS	43,801,984	44,267,292	43,460,757	41,309,102	41,579,128
31	Schedule 2- RSAE	448,709	428,550	407,590	360,384	326,767
32	Schedule 3- NRS	4,214,185	4,344,682	4,256,960	4,164,254	3,995,622
33	Schedule 3- NRH	10,845	12,069	11,931	10,394	10,826
34	Schedule 4- CS	26,250,627	26,911,703	27,823,411	26,651,913	26,322,914
35	Schedule 4- CSH	7,720	7,760	7,520	6,600	6,480
36	Schedule 5- IS	27,333,604	27,615,478	25,328,426	24,793,025	24,610,180
37	Schedule 6- MSL	203,547	119,398	71,086	68,077	64,798
38	Schedule 7- POL	-	-	-	-	-
39	Schedule 8- Resale	86,672	89,564	90,549	94,767	102,572
40		102,357,893	103,796,496	101,458,230	97,458,516	97,019,287
41						

	Customers	Actual	Actual	Actual	Actual	Actual	Average Change
	Rate Class	2020	2021	2022	2023	2024	2020-2024
44	Schedule 1- RS	5,083	5,089	5,099	5,117	5,130	11.69
45	Schedule 2- RSAE	35	35	34	32	30	(1.29)
46	Schedule 3- NRS	862	877	890	898	908	11.54
47	Schedule 3- NRH	2	2	2	2	1	(0.19)
48	Schedule 4- CS	365	365	369	375	381	4.04
49	Schedule 4- CSH	1	1	1	1	1	-
50	Schedule 5- IS	12	12	12	12	13	0.25
51	Schedule 6- MSL	2	2	2	2	2	-
52	Schedule 7- POL						-
53	Schedule 8- Resale	4	4	4	4	4	-
54		6,365	6,387	6,414	6,443	6,470	
55							
56		6,365	6,387	6,414	6,443	6,470	6,470

	Annual kWh Per Customer	Actual	Actual	Actual	Actual	Actual	Average	
	Rate Class	2020	2021	2022	2023	2024	2020-2024	
59	Schedule 1- RS	8,617	8,698	8,524	8,074	8,106	8,404	
60	Schedule 2- RSAE	12,820	12,244	11,872	11,175	10,953	11,813	
61	Schedule 3- NRS	4,891	4,957	4,783	4,640	4,402	4,734	
62	Schedule 3- NRH	5,423	6,035	5,966	5,197	8,661	6,256	
63	Schedule 4- CS	71,936	73,680	75,368	71,040	69,074	72,220	
64	Schedule 4- CSH	7,720	7,760	7,520	6,600	6,480	7,216	
65	Schedule 5- IS	2,277,800	2,301,290	2,110,702	2,037,783	1,893,091	2,124,133	
66	Schedule 6- MSL	101,774	59,699	35,543	34,039	32,399	33,219	
67	Schedule 7- POL							
68	Schedule 8- Resale	21,668	22,391	22,637	23,692	25,643	23,206	
69	AVERAGE	16,080	16,251	15,819	15,127	14,996	15,655	104,333,284

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Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026
Historic Billing Units

Line											
1	**Revenue Class 1 -- RURAL LIGHTING --RL-- 440 -- KWH**										
3	January	3,161,519	2,935,136	3,139,576	3,357,329	3,151,484	3,043,879	3,283,484	3,113,354	3,200,011	2,878,005
4	February	3,211,927	2,918,766	2,902,775	3,149,624	3,123,815	2,807,085	3,186,289	3,245,674	2,766,154	2,775,040
5	March	2,946,260	2,663,575	2,481,834	2,507,100	2,727,338	2,605,645	2,704,875	2,724,029	2,461,980	2,563,062
6	April	2,690,395	2,405,114	2,522,037	2,644,636	2,445,456	2,665,004	2,544,499	2,688,994	2,542,964	2,408,971
7	May	2,111,259	2,127,732	2,016,139	2,187,274	2,195,696	2,347,606	2,149,950	2,204,172	2,082,434	2,060,811
8	June	2,203,939	2,253,570	2,228,671	2,158,827	2,112,144	2,385,198	2,297,291	2,212,222	2,143,480	2,181,632
9	July	2,274,437	2,350,610	2,338,815	2,497,216	2,362,861	2,757,782	2,709,558	2,481,546	2,374,668	2,789,297
10	August	2,453,375	2,785,153	2,540,400	2,584,505	2,796,115	2,928,181	2,683,291	2,825,226	2,566,227	2,687,911
11	September	2,399,923	2,502,916	2,183,484	2,578,007	2,278,558	2,487,143	2,669,092	2,522,760	2,519,078	2,459,982
12	October	2,103,979	2,079,680	2,147,272	2,137,254	2,157,585	2,196,001	2,311,864	2,103,672	1,970,478	2,048,006
13	November	2,309,053	2,345,908	2,405,425	2,616,659	2,389,398	2,356,150	2,385,049	2,236,649	2,210,981	2,339,080
14	December	2,642,340	2,771,804	2,799,380	2,952,116	2,765,509	2,745,077	2,807,872	2,778,191	2,789,039	2,668,152
15		30,508,406	30,139,964	29,705,808	31,370,547	30,505,959	31,324,751	31,733,114	31,136,489	29,627,494	29,859,949
16											
17	**Revenue Class 5 -- TOWN LIGHTING --TL -- 440 -- KWH**										
18	January	1,107,471	1,041,669	1,066,256	1,159,362	1,075,855	1,050,980	1,186,861	1,087,977	1,207,074	1,024,591
19	February	1,163,775	1,046,673	1,040,921	1,184,832	1,164,467	1,030,794	1,086,561	1,188,065	995,972	1,018,510
20	March	1,100,269	951,353	855,472	914,609	947,416	915,263	1,005,541	1,007,878	886,045	985,314
21	April	988,837	862,263	1,000,365	945,674	950,265	885,828	984,327	978,015	930,988	852,411
22	May	751,298	750,145	696,125	804,674	711,427	876,033	710,715	782,788	722,491	747,134
23	June	761,071	747,600	748,802	760,684	738,607	774,005	782,660	748,620	685,189	735,893
24	July	843,265	807,314	782,598	843,482	730,247	826,533	891,307	853,427	781,561	882,771
25	August	905,963	956,980	943,248	884,537	1,080,876	1,173,193	1,009,622	1,034,591	984,797	1,037,651
26	September	824,268	1,017,021	810,505	985,395	834,824	995,167	1,072,871	948,215	885,248	945,232
27	October	802,203	756,136	737,861	805,708	718,295	730,149	798,424	791,649	747,172	722,684
28	November	788,333	777,102	783,517	865,493	787,969	838,607	779,969	806,370	755,156	798,332
29	December	838,272	921,351	953,825	954,051	937,238	897,690	943,260	883,237	957,323	854,064
30		10,875,025	10,635,607	10,419,495	11,108,501	10,677,486	10,994,242	11,252,118	11,110,832	10,539,016	10,604,587
31											
32	**Revenue Class 4 -- RURAL FARM LIGHTING --RFL-- 440 -- KWH**										
33	January	184,025	167,299	178,155	181,666	156,686	149,598	140,567	115,836	119,863	109,229
34	February	192,149	172,601	169,604	177,334	158,482	138,241	143,788	137,167	101,924	109,210
35	March	177,102	167,148	145,599	140,956	142,741	124,593	119,970	112,570	90,153	99,030
36	April	161,469	150,874	151,411	145,784	131,402	126,673	108,961	105,807	95,048	93,758
37	May	142,281	141,226	130,327	136,769	125,800	109,750	88,310	88,698	83,252	84,343
38	June	148,507	150,248	144,871	137,670	125,786	121,873	89,583	86,559	85,017	83,679
39	July	154,676	156,152	144,980	149,530	129,779	130,078	103,615	90,511	89,102	98,533
40	August	159,268	174,204	156,327	153,689	150,343	133,382	104,686	103,807	100,902	96,275
41	September	156,641	164,276	140,657	152,029	134,698	120,855	97,499	100,506	100,106	87,004
42	October	134,131	143,411	136,056	133,093	126,044	109,188	93,803	80,959	78,831	77,048
43	November	139,587	142,296	140,208	142,567	124,381	103,220	87,960	88,221	88,341	86,582
44	December	150,907	155,820	157,059	147,252	141,112	115,540	103,318	102,795	110,053	89,901
45		1,900,743	1,885,555	1,795,254	1,798,339	1,647,254	1,482,991	1,282,060	1,213,436	1,142,592	1,114,592
46											

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Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026
Historic Billing Units

Line											
1		**Revenue Class 1 -- RURAL LIGHTING --RL-- 440 -- KWH**									
47		**Revenue Class 2 -- RURAL COMMERCIAL POWER--RCP -- 442.01 -- KWH**									
48	January	1,760,220	1,963,860	1,633,620	1,371,120	1,725,840	1,690,860	1,508,160	1,401,600	1,497,595	1,330,754
49	February	1,726,980	1,954,680	1,828,500	1,603,656	1,560,600	1,498,080	1,565,040	1,236,120	1,449,254	1,289,709
50	March	1,634,520	2,204,460	1,738,500	1,465,504	1,472,100	1,507,920	1,540,500	1,471,320	1,309,458	1,199,848
51	April	1,835,280	1,943,400	1,860,420	1,565,940	1,574,520	1,685,100	1,741,320	1,463,280	1,391,404	1,352,119
52	May	1,933,980	1,950,000	1,814,520	1,678,860	1,763,160	1,242,540	1,493,940	1,398,780	1,336,606	1,315,240
53	June	1,996,560	1,994,040	1,994,040	1,767,780	1,548,960	1,301,100	1,636,500	1,396,740	1,426,037	1,476,249
54	July	2,055,960	1,838,940	1,754,760	1,711,860	1,734,900	1,661,160	1,737,900	1,296,540	1,289,359	1,275,781
55	August	1,885,980	1,962,660	1,836,720	1,733,520	1,726,320	1,555,740	1,600,680	1,433,760	1,469,258	1,259,193
56	September	1,863,120	2,002,860	1,619,700	1,376,100	1,449,960	1,555,320	1,411,560	1,357,920	1,207,566	1,155,949
57	October	1,909,500	1,778,460	1,581,000	1,387,560	1,454,820	1,358,340	1,357,260	1,175,580	1,163,562	1,192,411
58	November	1,777,860	1,749,840	1,444,200	1,283,820	1,531,320	1,473,120	1,348,920	1,358,160	1,152,854	1,329,544
59	December	1,790,220	1,748,100	1,334,928	1,445,220	1,509,720	1,579,800	1,486,500	1,441,358	1,296,561	1,391,920
60		22,170,180	23,091,300	20,440,908	18,390,940	19,052,220	18,109,080	18,428,280	16,431,158	15,989,514	15,568,717
61											
62		**Revenue Class 3 -- RURAL COMMERCIAL LIGHTING--RCL-- 442 -- KWH**									
63	January	454,244	394,224	425,486	433,834	403,841	414,577	422,748	410,015	419,661	376,362
64	February	476,844	441,730	416,972	440,874	443,586	407,453	427,854	455,252	388,697	377,435
65	March	449,108	417,123	380,715	393,329	404,479	388,460	395,576	392,746	375,856	382,289
66	April	448,698	403,217	398,615	413,367	417,636	372,917	405,699	415,534	389,775	351,486
67	May	330,895	329,662	304,773	339,684	326,891	293,808	305,812	317,078	304,862	297,715
68	June	341,781	340,824	330,672	332,836	315,745	303,214	318,330	303,453	307,735	304,800
69	July	356,154	351,714	345,214	354,436	330,606	341,038	354,418	325,623	315,194	340,121
70	August	393,436	397,191	376,535	356,788	403,089	369,571	365,108	353,681	346,972	335,369
71	September	345,311	377,082	320,313	357,171	335,755	336,173	354,153	338,543	337,127	319,700
72	October	321,864	319,091	304,561	314,522	318,533	302,795	312,641	300,177	290,167	281,482
73	November	323,648	330,428	319,427	349,931	328,253	333,072	314,385	297,836	312,575	304,376
74	December	352,371	371,762	367,609	384,296	384,092	351,107	367,958	347,022	375,633	324,487
75	TC	4,594,354	4,474,048	4,290,892	4,471,068	4,412,506	4,214,185	4,344,682	4,256,960	4,164,254	3,995,622
76											

Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026
Historic Billing Units

Line											
1	**Revenue Class 1 -- RURAL LIGHTING --RL-- 440 -- KWH**										
77	**Revenue Class 6 -- TOWN COMMERCIAL POWER --TCP -- 442.01 -- KWH**										
78	January	1,701,880	1,852,620	727,280	787,940	788,043	773,476	696,501	699,164	691,334	698,575
79	February	1,756,000	1,774,800	727,400	732,081	752,783	699,207	690,371	675,658	644,161	695,233
80	March	1,599,460	1,886,760	696,640	749,959	718,559	707,962	686,382	673,360	632,122	664,603
81	April	1,599,960	1,676,480	764,340	799,909	699,196	697,919	704,901	660,693	673,135	713,890
82	May	1,833,600	1,748,460	750,480	756,471	806,907	687,793	710,716	719,965	691,214	735,645
83	June	1,931,880	1,907,700	896,020	871,950	821,053	818,324	829,985	840,786	800,200	863,541
84	July	1,889,360	1,963,240	944,560	905,070	972,636	953,553	918,672	892,202	862,536	939,350
85	August	1,906,140	1,793,800	954,400	968,287	942,863	894,980	898,791	918,521	924,601	894,347
86	September	1,987,820	1,719,040	841,540	858,384	832,837	817,330	864,010	834,907	835,283	772,826
87	October	1,926,700	1,070,740	824,100	815,437	779,387	759,716	806,048	672,450	721,456	719,113
88	November	1,740,340	799,900	729,920	731,626	755,617	700,167	657,049	656,835	667,792	704,465
89	December	1,691,120	775,500	752,363	752,410	773,655	714,097	723,772	652,727	659,677	639,875
90	TC	21,564,260	18,969,040	9,609,043	9,729,524	9,643,536	9,224,524	9,187,198	8,897,268	8,803,511	9,041,463
91											
92	**Revenue Class 7 -- TOWN COMMERCIAL LIGHTING -- TCL --442 -- KWH**										
93	January	2,521,053	2,327,347	2,521,517	2,532,921	2,503,929	2,408,661	2,343,715	2,402,873	2,561,604	2,368,626
94	February	2,617,925	2,377,544	2,530,811	2,679,357	2,621,862	2,417,080	2,391,324	2,613,728	2,358,165	2,344,982
95	March	2,460,840	2,252,862	2,190,274	2,192,021	2,319,703	2,214,704	2,210,154	2,231,882	2,153,322	2,355,081
96	April	2,386,201	2,221,045	2,389,658	2,319,301	2,248,644	2,116,593	2,244,717	2,308,679	2,251,674	2,137,912
97	May	2,121,754	2,051,801	2,020,998	2,135,284	2,007,788	1,823,700	1,860,821	1,993,016	1,960,657	1,904,008
98	June	2,303,789	2,264,560	2,254,726	2,214,001	2,170,127	1,870,660	2,109,960	2,160,503	2,070,781	2,108,065
99	July	2,320,066	2,340,983	2,308,740	2,424,726	2,165,801	2,218,217	2,328,523	2,544,960	2,144,124	2,288,585
100	August	2,460,835	2,654,681	2,649,972	2,538,411	2,711,557	2,572,413	2,482,890	2,549,734	2,380,908	2,327,700
101	September	2,335,691	2,653,053	2,286,069	2,582,990	2,312,090	2,337,646	2,519,022	2,396,487	2,266,112	2,272,314
102	October	2,219,728	2,182,010	2,250,965	2,209,054	2,177,376	2,056,659	2,164,737	2,137,824	2,010,947	2,005,363
103	November	2,124,762	2,365,179	2,223,503	2,364,928	2,130,658	2,144,907	2,111,992	2,232,724	2,164,321	2,134,430
104	December	2,119,019	2,335,679	2,274,114	2,229,952	2,207,496	2,069,387	2,143,848	2,251,001	2,329,298	2,075,848
105	TC	27,991,663	28,026,744	27,901,347	28,422,946	27,577,031	26,250,627	26,911,703	27,823,411	26,651,913	26,322,914
106											
107	**Revenue Class 9 -- PUBLIC MUNICIPAL STREET LIGHTING -- 444 -- KWH**										
108	January	18,333	17,853	17,728	19,828	19,826	19,342	14,669	6,210	5,782	5,519
109	February	18,283	17,803	17,728	19,828	19,826	19,182	13,016	6,203	5,782	5,389
110	March	18,283	17,778	17,728	19,828	19,826	18,794	12,434	6,203	5,782	5,389
111	April	18,283	17,778	19,828	19,828	19,826	17,130	12,008	5,996	5,782	5,389
112	May	18,258	17,778	19,828	19,896	19,826	17,130	12,008	5,841	5,782	5,389
113	June	18,278	17,753	19,828	19,896	19,826	17,130	10,567	5,841	5,600	5,389
114	July	18,253	17,753	19,828	19,826	19,826	16,936	9,997	5,841	5,600	5,389
115	August	18,203	17,753	19,828	19,826	19,826	16,659	8,429	5,841	5,600	5,389
116	September	18,178	17,753	19,828	19,826	19,747	15,862	7,503	5,789	5,600	5,389
117	October	18,433	17,753	19,828	19,826	19,657	15,282	6,347	5,757	5,589	5,389
118	November	18,028	17,728	19,828	19,826	19,612	15,050	6,210	5,782	5,589	5,389
119	December	17,953	17,728	19,828	19,826	19,567	15,050	6,210	5,782	5,589	5,389
120	TC	218,766	213,211	231,636	238,060	237,191	203,547	119,398	71,086	68,077	64,798
121											

Wellsboro Electric Company
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Line											
1	**Revenue Class 1 -- RURAL LIGHTING --RL-- 440 -- KWH**										
122	**Revenue Class 8 -- SALES FOR RESALES -- 447 -- REVENUE**										
123	January		10,011	7,476	13,065	9,851	9,862	7,369	10,440	8,248	7,615	8,415
124	February		12,177	11,762	10,010	7,485	8,172	7,710	8,981	9,937	7,077	8,654
125	March		9,589	9,803	9,083	7,802	7,588	6,733	7,141	7,352	6,723	7,983
126	April		9,068	8,717	9,570	10,213	6,872	5,585	6,809	7,566	6,495	8,201
127	May		8,059	5,431	7,090	7,312	5,707	6,117	6,206	6,348	7,051	7,694
128	June		8,695	10,512	7,767	7,988	7,642	6,237	6,874	6,948	6,542	8,191
129	July		8,247	9,053	7,594	8,159	7,107	7,298	7,397	7,737	8,956	8,790
130	August		9,053	7,856	7,270	6,845	7,498	7,722	6,194	6,945	8,295	8,426
131	September		8,274	9,259	6,431	7,659	7,533	7,802	7,081	6,806	9,159	7,922
132	October		8,790	8,174	8,790	8,422	5,970	6,443	5,820	6,379	6,486	7,068
133	November		10,382	10,168	7,388	8,613	7,865	7,927	7,381	7,215	8,192	9,268
134	December		13,128	16,806	12,946	17,974	11,419	9,729	9,240	9,068	12,176	11,960
135			115,473	115,017	107,004	108,323	93,235	86,672	89,564	90,549	94,767	102,572
136												
137	**Revenue Class 11 -- 3H SCH-HEAT -- RCL -- 442 -- KWH**											
138	January		3,091	1,055	3,273	3,696	1,310	1,550	1,248	863	1,630	801
139	February		4,048	1,827	3,392	2,595	2,361	1,846	1,601	2,316	1,272	1,548
140	March		4,124	2,415	2,545	782	1,493	1,621	1,812	1,494	1,164	2,020
141	April		2,051	1,447	3,033	1,020	1,169	706	770	1,160	1,061	1,533
142	May		907	1,299	766	678	493	503	315	592	535	434
143	June		736	607	1,058	981	641	345	462	731	376	549
144	July		685	640	941	1,076	784	679	835	995	818	750
145	August		831	783	1,064	1,131	1,014	972	908	1,068	1,140	748
146	September		832	856	821	1,192	903	980	1,212	881	833	725
147	October		633	1,049	864	977	859	796	1,085	738	598	680
148	November		728	808	838	857	632	465	810	521	419	591
149	December		830	2,098	1,968	1,045	963	382	1,011	572	548	447
150		TC	19,496	14,884	20,563	16,030	12,622	10,845	12,069	11,931	10,394	10,826
151												
152	**Revenue Class 12 -- 4H CSH-HEAT -- TCL -- 442 -- KWH**											
153	January		4,880	1,040	640	480	680	520	560	520	600	440
154	February		4,400	640	720	680	480	560	560	600	480	520
155	March		4,240	680	440	520	520	480	560	480	400	520
156	April		3,160	760	720	640	600	560	520	520	560	480
157	May		1,040	480	480	560	480	360	320	440	400	400
158	June		680	680	600	920	640	480	480	440	440	480
159	July		840	840	1,040	1,240	760	920	880	960	640	760
160	August		1,200	1,160	1,120	1,360	1,600	1,480	1,040	1,240	960	1,000
161	September		840	1,480	880	1,720	1,040	1,160	1,520	1,160	800	680
162	October		840	720	680	720	640	520	560	520	560	520
163	November		920	440	400	400	440	320	400	280	320	280
164	December		1,400	600	520	520	480	360	360	360	440	400
165		TC	24,440	9,520	8,240	9,760	8,360	7,720	7,760	7,520	6,600	6,480

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Line											
1	**Revenue Class 1 -- RURAL LIGHTING --RL-- 440 -- KWH**										
166											
167	**Revenue Class 13 -- 2-RSAE -- ALL ELECTRIC -- RL/TL --440 -- KWH**										
168	January	80,994	61,892	71,130	69,473	59,790	56,346	54,348	50,304	53,596	38,400
169	February	91,191	69,959	66,215	64,920	65,842	54,434	54,236	60,310	46,549	40,881
170	March	87,925	63,023	51,407	47,276	53,891	50,216	46,753	49,731	41,043	39,302
171	April	70,268	50,197	54,197	49,821	47,608	44,186	40,036	44,380	40,036	33,270
172	May	41,405	41,550	31,774	38,695	30,951	40,178	28,818	29,501	25,632	24,157
173	June	31,803	32,017	31,047	25,344	24,854	29,068	26,171	19,791	20,698	18,334
174	July	30,755	28,971	26,731	26,364	23,455	25,345	25,511	21,285	18,961	19,650
175	August	30,434	31,678	28,873	26,701	29,544	28,128	26,685	23,193	20,284	19,535
176	September	29,774	30,516	26,781	27,767	25,190	24,864	27,153	21,828	19,649	19,350
177	October	32,097	28,738	26,306	25,912	25,321	23,805	24,887	21,403	16,831	16,729
178	November	42,967	37,944	36,618	40,600	34,267	31,724	31,164	27,088	22,535	25,219
179	December	51,279	55,094	54,279	54,550	50,495	40,415	42,788	38,776	34,570	31,940
180		620,892	531,579	505,358	497,423	471,208	448,709	428,550	407,590	360,384	326,767
181											
182		**2015 ACTUAL**	**2016 ACTUAL**	**2017 ACTUAL**	**2018 ACTUAL**						
183	January	11,007,721	10,771,471	9,797,726	9,927,500	9,897,146	9,617,158	9,663,301	9,296,964	9,766,365	8,839,717
184	February	11,275,699	10,788,785	9,715,048	10,063,266	9,922,276	9,081,672	9,569,621	9,631,030	8,765,487	8,667,111
185	March	10,491,720	10,636,980	8,570,237	8,439,686	8,815,654	8,542,391	8,731,698	8,679,045	7,964,048	8,304,441
186	April	10,213,670	9,741,292	9,174,194	8,916,133	8,543,194	8,618,201	8,794,567	8,680,624	8,328,922	7,959,420
187	May	9,294,736	9,165,564	7,793,300	8,106,157	7,995,126	7,445,518	7,367,931	7,547,219	7,220,916	7,182,970
188	June	9,747,719	9,720,111	8,658,102	8,298,877	7,886,025	7,627,634	8,108,863	7,782,634	7,552,095	7,786,802
189	July	9,952,698	9,866,210	8,675,801	8,942,985	8,478,762	8,939,539	9,088,613	8,521,627	7,891,519	8,649,777
190	August	10,224,718	10,783,899	9,515,757	9,275,600	9,870,645	9,682,421	9,188,324	9,257,607	8,809,944	8,673,544
191	September	9,970,672	10,496,112	8,257,009	8,948,240	8,233,135	8,700,302	9,032,676	8,535,802	8,186,561	8,047,073
192	October	9,478,898	8,385,962	8,038,283	7,858,485	7,784,487	7,559,694	7,883,476	7,297,108	7,012,677	7,076,493
193	November	9,276,608	8,577,741	8,111,272	8,425,320	8,110,412	8,004,729	7,731,289	7,717,681	7,389,075	7,737,556
194	December	9,668,839	9,172,342	8,728,819	8,959,212	8,801,746	8,538,634	8,636,137	8,510,889	8,570,907	8,094,383
195	TC	120,603,698	118,106,469	105,035,548	106,161,461	104,338,608	102,357,893	103,796,496	101,458,230	97,458,516	97,019,287

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Wellsboro Electric Company
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Line							
1							
3	January	3,519	3,518	3,524	3,533	3,552	3,562
4	February	3,519	3,521	3,525	3,532	3,548	3,561
5	March	3,519	3,523	3,527	3,532	3,549	3,561
6	April	3,519	3,524	3,523	3,533	3,549	3,563
7	May	3,514	3,522	3,528	3,535	3,558	3,566
8	June	3,520	3,527	3,530	3,535	3,555	3,569
9	July	3,520	3,529	3,529	3,533	3,555	3,576
10	August	3,519	3,535	3,533	3,535	3,558	3,575
11	September	3,518	3,530	3,531	3,542	3,556	3,574
12	October	3,522	3,530	3,530	3,547	3,557	3,578
13	November	3,521	3,524	3,531	3,548	3,560	3,568
14	December	3,520	3,526	3,535	3,552	3,562	3,566
15		42,230	42,309	42,346	42,457	42,659	42,819
16							
17							
18	January	1,475	1,467	1,474	1,475	1,480	1,482
19	February	1,475	1,467	1,473	1,475	1,480	1,481
20	March	1,474	1,466	1,472	1,476	1,480	1,482
21	April	1,470	1,467	1,474	1,476	1,480	1,483
22	May	1,469	1,468	1,474	1,476	1,479	1,483
23	June	1,468	1,467	1,474	1,477	1,478	1,484
24	July	1,467	1,468	1,476	1,477	1,478	1,484
25	August	1,466	1,467	1,477	1,477	1,479	1,483
26	September	1,465	1,472	1,477	1,478	1,478	1,483
27	October	1,467	1,471	1,476	1,478	1,478	1,483
28	November	1,467	1,471	1,476	1,478	1,479	1,483
29	December	1,468	1,474	1,474	1,479	1,481	1,483
30		17,631	17,625	17,697	17,722	17,750	17,794
31							
32	**Re**						
33	January	91	90	87	84	84	80
34	February	91	90	87	84	84	80
35	March	91	89	87	84	84	80
36	April	91	89	87	84	83	79
37	May	91	89	86	84	82	78
38	June	91	89	85	84	82	78
39	July	91	89	85	84	82	78
40	August	90	88	85	84	82	78
41	September	90	87	85	84	82	78
42	October	90	87	85	84	82	78
43	November	90	87	85	84	82	78
44	December	90	87	85	84	80	78
45		1,087	1,061	1,029	1,008	989	943
46							

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Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026
Historic Billing Units

Line								
1								
47		**Re**						
48	January		6	6	6	6	6	7
49	February		6	6	6	6	6	7
50	March		6	6	6	6	6	7
51	April		6	6	6	6	6	7
52	May		6	6	6	6	6	7
53	June		6	6	6	6	6	7
54	July		6	6	6	6	6	7
55	August		5	6	6	6	6	7
56	September		6	6	6	6	6	7
57	October		6	6	6	6	6	7
58	November		6	6	6	6	7	7
59	December		6	6	6	6	7	7
60			71	72	72	72	74	84
61								
62		**Re**						
63	January		840	855	874	885	893	901
64	February		841	854	875	886	895	901
65	March		843	853	877	887	897	903
66	April		845	855	876	887	897	904
67	May		844	858	876	889	896	910
68	June		844	860	876	891	897	909
69	July		844	866	877	884	893	911
70	August		846	862	875	894	900	912
71	September		846	867	876	895	900	911
72	October		848	867	876	895	901	910
73	November		848	869	879	894	900	910
74	December		850	873	881	894	901	911
75		TC	10,139	10,339	10,518	10,681	10,770	10,893
76								

Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026
Historic Billing Units

Line								
1								
77		**Re**						
78	January		6	6	6	6	6	6
79	February		6	6	6	6	6	6
80	March		6	6	6	6	6	6
81	April		6	6	6	6	6	6
82	May		6	6	6	6	6	6
83	June		6	6	6	6	6	6
84	July		6	6	6	6	6	6
85	August		6	6	6	6	6	6
86	September		6	6	6	6	6	6
87	October		6	6	6	6	6	6
88	November		6	6	6	6	6	6
89	December		6	6	6	6	6	6
90		TC	72	72	72	72	72	72
91								
92		**Re**						
93	January		359	363	365	365	370	379
94	February		359	364	364	366	371	381
95	March		358	364	364	368	371	381
96	April		362	363	363	368	373	382
97	May		360	363	365	368	373	379
98	June		360	366	365	370	375	379
99	July		360	366	367	376	381	380
100	August		360	370	367	370	377	380
101	September		358	365	366	369	377	381
102	October		361	365	366	370	376	382
103	November		363	365	365	370	379	384
104	December		362	365	366	370	379	385
105		TC	4,322	4,379	4,383	4,430	4,502	4,573
106								
107		**Re**						
108	January		2	2	2	2	2	2
109	February		2	2	2	2	2	2
110	March		2	2	2	2	2	2
111	April		2	2	2	2	2	2
112	May		2	2	2	2	2	2
113	June		2	2	2	2	2	2
114	July		2	2	2	2	2	2
115	August		2	2	2	2	2	2
116	September		2	2	2	2	2	2
117	October		2	2	2	2	2	2
118	November		2	2	2	2	2	2
119	December		2	2	2	2	2	2
120		TC	24	24	24	24	24	24
121								

Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026
Historic Billing Units

Line							
1							
122							
123	January	4	4	4	4	4	4
124	February	4	4	4	4	4	4
125	March	4	4	4	4	4	4
126	April	4	4	4	4	4	4
127	May	4	4	4	4	4	4
128	June	4	4	4	4	4	4
129	July	4	4	4	4	4	4
130	August	4	4	4	4	4	4
131	September	4	4	4	4	4	4
132	October	4	4	4	4	4	4
133	November	4	4	4	4	4	4
134	December	4	4	4	4	4	4
135		48	48	48	48	48	48
136							
137	**Re**						
138	January	2	2	2	2	2	2
139	February	2	2	2	2	2	2
140	March	2	2	2	2	2	2
141	April	2	2	2	2	2	1
142	May	2	2	2	2	2	1
143	June	2	2	2	2	2	1
144	July	2	2	2	2	2	1
145	August	2	2	2	2	2	1
146	September	2	2	2	2	2	1
147	October	2	2	2	2	2	1
148	November	2	2	2	2	2	1
149	December	2	2	2	2	2	1
150	TC	24	24	24	24	24	15
151							
152	**Re**						
153	January	1	1	1	1	1	1
154	February	1	1	1	1	1	1
155	March	1	1	1	1	1	1
156	April	1	1	1	1	1	1
157	May	1	1	1	1	1	1
158	June	1	1	1	1	1	1
159	July	1	1	1	1	1	1
160	August	1	1	1	1	1	1
161	September	1	1	1	1	1	1
162	October	1	1	1	1	1	1
163	November	1	1	1	1	1	1
164	December	1	1	1	1	1	1
165	TC	12	12	12	12	12	12

WP_B3

Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026
Historic Billing Units

Line								
1								
166								
167								
168	January		37	35	35	35	33	31
169	February		37	35	35	35	33	31
170	March		37	35	35	35	33	31
171	April		36	35	35	35	33	30
172	May		36	35	35	35	33	30
173	June		36	35	35	35	33	30
174	July		36	35	35	35	33	30
175	August		36	35	35	34	32	29
176	September		35	35	35	34	31	29
177	October		35	35	35	33	31	29
178	November		35	35	35	33	31	29
179	December		35	35	35	33	31	29
180			431	420	420	412	387	358
181								
182								
183	January		6,342	6,349	6,380	6,398	6,433	6,457
184	February		6,343	6,352	6,380	6,399	6,432	6,457
185	March		6,343	6,351	6,383	6,403	6,435	6,460
186	April		6,344	6,354	6,379	6,404	6,436	6,462
187	May		6,335	6,356	6,385	6,408	6,442	6,467
188	June		6,340	6,365	6,386	6,413	6,441	6,470
189	July		6,339	6,374	6,390	6,410	6,443	6,480
190	August		6,337	6,378	6,393	6,415	6,449	6,478
191	September		6,333	6,377	6,391	6,423	6,445	6,477
192	October		6,344	6,376	6,389	6,428	6,446	6,481
193	November		6,345	6,372	6,392	6,428	6,453	6,473
194	December		6,346	6,381	6,397	6,433	6,456	6,473
195		TC	76,091	76,385	76,645	76,962	77,311	77,635

Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026
Sales Recap
Period Ending December 31, 2024

Line	SC	Customer Class	Type	January	February	March	April	May	June	July	August	September	October	November	December	Totals
1	1	1-RL	D	214,817	208,780	196,332	187,288	166,871	174,064	209,730	203,802	190,504	166,278	183,403	202,569	2,304,439
2	1	1-RL-STAS	S	(49)	(47)	(44)	(42)	(37)	(36)	(44)	(43)	(40)	(34)	(38)	(46)	(499)
3	1	1-RL-GEN	G	265,322	255,828	236,288	222,082	189,986	177,430	226,852	218,606	200,069	166,563	190,236	243,734	2,592,996
4	1	1-RFL	D	7,622	7,621	7,024	6,715	6,151	6,100	6,978	6,839	6,295	5,706	6,270	6,465	79,786
5	1	1-RFL-STAS	S	(2)	(2)	(2)	(2)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(18)
6	1	1-RFL-GEN	G	10,070	10,068	9,130	8,643	7,776	6,805	8,014	7,830	7,076	6,266	7,042	8,212	96,931
7	1	1-TL	D	78,197	77,838	75,883	68,084	61,909	61,273	69,907	78,991	73,564	60,511	64,943	68,218	839,318
8	1	1-TL-STAS	S	(18)	(18)	(17)	(15)	(14)	(12)	(15)	(17)	(15)	(12)	(13)	(15)	(181)
9	1	1-TL-GEN	G	94,457	93,896	90,836	78,584	68,878	59,850	71,796	84,392	76,876	58,776	64,928	78,019	921,288
10	2	2-RSAE - RL/TL	D	2,371	2,498	2,417	2,108	1,632	1,330	1,397	1,384	1,370	1,236	1,671	2,016	21,430
11	2	2-RSAE - RL/TL - ST/	S	(1)	(1)	(1)	(1)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(1)	(5)
12	2	2-RSAE - RL/TL - GE	G	3,540	3,769	3,623	3,067	2,227	1,491	1,598	1,589	1,574	1,361	2,051	2,918	28,807
13	3	3-RCL	D	40,591	40,672	41,060	38,716	34,724	35,285	37,933	37,534	36,412	33,490	35,221	36,750	448,390
14	3	3-RCL-STAS	S	(7)	(7)	(7)	(6)	(5)	(5)	(6)	(6)	(5)	(5)	(5)	(6)	(72)
15	3	3-RCL-GEN	G	33,488	33,632	34,103	31,305	26,419	23,853	26,761	26,375	25,065	22,077	23,925	28,801	335,804
16	3H	3H-Sch Heat - RCL	D	92	156	196	154	49	59	76	76	74	70	62	50	1,112
17	3H	3H-Sch Heat - RCL -	S	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
18	3H	3H-Sch Heat - RCL -	G	74	143	186	141	40	45	61	61	59	55	48	41	954
19	4	4-TCL	D	120,732	121,897	119,458	113,857	109,999	117,659	124,818	126,185	122,958	115,185	116,954	115,003	1,424,706
20	4	4-TCL - STAS	S	(29)	(29)	(28)	(26)	(24)	(25)	(27)	(28)	(27)	(25)	(26)	(27)	(319)
21	4	4-TCL - GEN	G	159,476	158,058	156,153	139,557	123,851	125,035	140,085	145,484	142,473	127,518	135,353	147,699	1,700,741
22	4H	4H-CSH Heat - TCL	D	75	80	80	78	72	78	96	112	91	80	64	72	979
23	4H	4H-CSH Heat - TCL -	S	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
24	4H	4H-CSH Heat - TCL -	G	41	48	48	44	37	39	62	81	55	42	23	37	557
25	5	5-RCP	D	42,207	42,747	41,958	42,411	43,628	45,376	46,185	46,333	45,882	43,897	42,211	42,475	525,311
26	5	5-RCP - STAS	S	(7)	(7)	(7)	(7)	(7)	(8)	(9)	(8)	(8)	(8)	(7)	(7)	(91)
27	5	5-RCP - GEN	G	33,632	34,457	26,853	29,187	29,967	34,155	40,118	36,587	29,644	31,879	30,146	31,061	387,686
28	5	5-TCP	D	19,414	20,194	20,997	21,498	22,355	25,088	25,389	25,258	24,365	24,006	20,915	19,204	268,684
29	5	5-TCP - STAS	S	(6)	(6)	(6)	(6)	(6)	(8)	(9)	(8)	(7)	(7)	(7)	(7)	(84)
30	5	5-TCP -GEN	G	44,143	42,863	39,229	43,466	43,700	55,006	68,794	59,909	48,669	49,432	45,845	49,172	590,226
31	6	6-ML - Public Street I	D	1,127	1,121	1,121	1,121	1,121	1,121	1,121	1,121	1,121	1,121	1,121	1,121	13,458
32	6	6-ML PSL - STAS	S	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(2)
33	6	6-ML PSL - GEN	G	508	496	496	496	496	437	437	437	437	437	437	491	5,609
34																
35	8	8-EU - Sales for Resa	D	735	756	697	716	672	715	768	736	692	617	809	1,044	8,957
36	8	8-EU - Sales for Resa	G	776	798	736	756	709	666	715	685	644	575	754	1,093	8,907
37		Totals Sales Revenue		1,173,389	1,158,300	1,104,792	1,039,970	943,176	952,865	1,109,579	1,110,294	1,035,863	917,086	974,336	1,086,155	12,605,806
38																
39		Distribution		527,981	524,361	507,223	482,745	449,184	468,149	524,398	528,370	503,327	452,197	473,647	494,987	5,936,569
40		STAS		(118)	(117)	(112)	(105)	(95)	(96)	(111)	(112)	(104)	(92)	(99)	(110)	(1,270)
41		Generation		645,526	634,056	597,681	557,330	494,086	484,812	585,293	582,035	532,641	464,981	500,788	591,278	6,670,507
42		Total Sales Revenue		1,173,389	1,158,300	1,104,792	1,039,970	943,176	952,865	1,109,579	1,110,294	1,035,863	917,086	974,336	1,086,155	12,605,806
43																12,607,075

Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026
Sales Recap
Period Ending December 31, 2024

Line	SC	Customer Class / kWh Generation	Type	January	February	March	April	May	June	July	August	September	October	November	December	Totals
44				January	February	March	April	May	June	July	August	September	October	November	December	Totals
45		Residential		4,050,225	3,943,641	3,686,708	3,388,410	2,916,445	3,019,538	3,790,251	3,841,372	3,511,568	2,864,467	3,249,213	3,644,057	41,905,895
46		Commercial - Small	RCL	377,163	378,983	384,309	353,019	298,149	305,349	340,871	336,117	320,425	282,162	304,967	324,934	4,006,448
47		Commercial - Small	TCL	2,369,066	2,345,502	2,355,601	2,138,392	1,904,408	2,108,545	2,289,345	2,328,700	2,272,994	2,005,883	2,134,710	2,076,248	26,329,394
48		Commercial - Large		2,029,329	1,984,942	1,864,451	2,066,009	2,050,885	2,339,790	2,215,131	2,153,540	1,928,775	1,911,524	2,034,009	2,031,795	24,610,180
49		ML - Public Street Lights		5,519	5,389	5,389	5,389	5,389	5,389	5,389	5,389	5,389	5,389	5,389	5,389	64,798
50		Sales for Resale		8,415	8,654	7,983	8,201	7,694	8,191	8,790	8,426	7,922	7,068	9,268	11,960	102,572
51																-
52																-
53		**Total KWH**		8,839,717	8,667,111	8,304,441	7,959,420	7,182,970	7,786,802	8,649,777	8,673,544	8,047,073	7,076,493	7,737,556	8,094,383	97,019,287
54																
55		Source: Bill-Totals-Tabs		1st Qtr Total KWh			2nd Qtr Total KWh			3rd Qtr Total KWh			4th Qtr Total KWh			
56						25,811,269			22,929,192			25,370,394			22,908,432	
57																
58	1			670,418	653,965	615,430	571,338	501,520	485,473	593,215	600,399	554,326	464,054	516,769	607,155	6,834,061
59	2			5,910	6,266	6,040	5,174	3,859	2,821	2,995	2,972	2,944	2,596	3,722	4,933	50,232
60	3			74,072	74,297	75,157	70,015	61,138	59,133	64,688	63,903	61,472	55,562	59,141	65,546	784,122
61	3H			166	298	382	296	89	103	137	136	133	125	110	91	2,066
62	4			280,179	279,927	275,582	253,388	233,827	242,669	264,876	271,641	265,404	242,678	252,282	262,676	3,125,128
63	4H			116	128	128	122	109	117	158	193	146	123	87	109	1,536
64	5			139,382	140,248	129,024	136,548	139,637	159,609	180,468	168,070	148,545	149,199	139,104	141,898	1,771,732
65	6			1,635	1,617	1,617	1,617	1,617	1,558	1,558	1,558	1,558	1,558	1,558	1,612	19,065
66	8			1,511	1,553	1,433	1,472	1,381	1,381	1,482	1,421	1,336	1,192	1,563	2,137	17,863
67				1,173,389	1,158,300	1,104,792	1,039,970	943,176	952,865	1,109,579	1,110,294	1,035,863	917,086	974,336	1,086,155	12,605,806
68																
69	1		D	300,637	294,239	279,239	262,087	234,932	241,437	286,614	289,632	270,362	232,496	254,617	277,252	3,223,543
70	1		S	(68)	(67)	(63)	(59)	(51)	(49)	(60)	(61)	(56)	(47)	(53)	(62)	(697)
71	1		G	369,849	359,792	336,253	309,310	266,639	244,086	306,661	310,828	284,021	231,605	262,205	329,965	3,611,216
72				670,418	653,965	615,430	571,338	501,520	485,473	593,215	600,399	554,326	464,054	516,769	607,155	6,834,061
73																
74	5		D	61,621	62,942	62,955	63,909	65,983	70,465	71,574	71,591	70,247	67,903	63,127	61,679	793,994
75	5		S	(13)	(14)	(13)	(14)	(14)	(16)	(18)	(17)	(15)	(15)	(14)	(14)	(175)
76	5		G	77,775	77,320	66,081	72,653	73,668	89,160	108,912	96,495	78,313	81,311	75,991	80,233	977,913
77				139,382	140,248	129,024	136,548	139,637	159,609	180,468	168,070	148,545	149,199	139,104	141,898	1,771,732
78																

Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026
Sales Recap
Period Ending December 31, 2024

Line	SC	Customer Class	Type	January	February	March	April	May	June	July	August	September	October	November	December	Totals
79		Residential	D	300,637	294,239	279,239	262,087	234,932	241,437	286,614	289,632	270,362	232,496	254,617	277,252	3,223,543
80		RSAE	D	2,371	2,498	2,417	2,108	1,632	1,330	1,397	1,384	1,370	1,236	1,671	2,016	21,430
81		NRS	D	40,591	40,672	41,060	38,716	34,724	35,285	37,933	37,534	36,412	33,490	35,221	36,750	448,390
82		NRH	D	92	156	196	154	49	59	76	76	74	70	62	50	1,112
83		CS	D	120,732	121,897	119,458	113,857	109,999	117,659	124,818	126,185	122,958	115,185	116,954	115,003	1,424,706
84		CSH	D	75	80	80	78	72	78	96	112	91	80	64	72	979
85		IS	D	61,621	62,942	62,955	63,909	65,983	70,465	71,574	71,591	70,247	67,903	63,127	61,679	793,994
86		ML	D	1,127	1,121	1,121	1,121	1,121	1,121	1,121	1,121	1,121	1,121	1,121	1,121	13,458
87		EU	D	735	756	697	716	672	715	768	736	692	617	809	1,044	8,957
88				527,981	524,361	507,223	482,745	449,184	468,149	524,398	528,370	503,327	452,197	473,647	494,987	5,936,569
89																
90		Residential	G	369,849	359,792	336,253	309,310	266,639	244,086	306,661	310,828	284,021	231,605	262,205	329,965	3,611,216
91		RSAE	G	3,540	3,769	3,623	3,067	2,227	1,491	1,598	1,589	1,574	1,361	2,051	2,918	28,807
92		NRS	G	33,488	33,632	34,103	31,305	26,419	23,853	26,761	26,375	25,065	22,077	23,925	28,801	335,804
93		NRH	G	74	143	186	141	40	45	61	61	59	55	48	41	954
94		CS	G	159,476	158,058	156,153	139,557	123,851	125,035	140,085	145,484	142,473	127,518	135,353	147,699	1,700,741
95		CSH	G	41	48	48	44	37	39	62	81	55	42	23	37	557
96		IS	G	77,775	77,320	66,081	72,653	73,668	89,160	108,912	96,495	78,313	81,311	75,991	80,233	977,913
97		ML	G	508	496	496	496	496	437	437	437	437	437	437	491	5,609
98		EU	G	776	798	736	756	709	666	715	685	644	575	754	1,093	8,907
99				645,526	634,056	597,681	557,330	494,086	484,812	585,293	582,035	532,641	464,981	500,788	591,278	6,670,507
100																
101		Residential	S	(68)	(67)	(63)	(59)	(51)	(49)	(60)	(61)	(56)	(47)	(53)	(62)	(697)
102		RSAE	S	(1)	(1)	(1)	(1)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(1)	(5)
103		NRS	S	(7)	(7)	(7)	(6)	(5)	(5)	(6)	(6)	(5)	(5)	(5)	(6)	(72)
104		NRH	S	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
105		CS	S	(29)	(29)	(28)	(26)	(24)	(25)	(27)	(28)	(27)	(25)	(26)	(27)	(319)
106		CSH	S	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
107		IS	S	(13)	(14)	(13)	(14)	(14)	(16)	(18)	(17)	(15)	(15)	(14)	(14)	(175)
108		ML	S	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(2)
109		EU	S													
110				(118)	(117)	(112)	(105)	(95)	(96)	(111)	(112)	(104)	(92)	(99)	(110)	(1,270)

Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026
Total Operating Revenues
January 1, 2024 to December 31, 2024

Line	Month	MWh Sales	Net Revenue	STAS	Unbilled Revenue	Allocation E Factor	Sub Total Revenues	#450 Forfeited Discounts	#454 Rent from Electric Property	#456 Other Electric Revenues	#495 GSSR over/under Recovery	#495.10 Over/under Collection Unbilled	Total Revenues
1	January	8,839.717	$ 1,173,507	$ (118)	$ -	$ 15,970	$ 1,189,359	$ 2,481	$ 22,181	$ 298	$ (29,097)	$ -	$ 1,185,223
2	February	8,667.111	$ 1,158,417	$ (117)	$ -	$ 15,683	$ 1,173,983	$ 3,353	$ 19,279	$ 1,733	$ (102,278)	$ -	$ 1,096,071
3	March	8,304.441	$ 1,104,904	$ (112)	$ -	$ 14,947	$ 1,119,739	$ 3,073	$ 19,279	$ 517	$ (83,267)	$ -	$ 1,059,341
4	April	7,959.420	$ 1,040,075	$ (105)	$ -	$ 13,712	$ 1,053,682	$ 2,403	$ 20,179	$ 457	$ (47,009)	$ -	$ 1,029,714
5	May	7,182.970	$ 943,271	$ (95)	$ -	$ 11,730	$ 954,906	$ 2,254	$ 18,379	$ 986	$ 76,892	$ -	$ 1,053,417
6	June	7,786.802	$ 952,961	$ (96)	$ -	$ 13,666	$ 966,531	$ 1,849	$ 19,279	$ 3,558	$ 46,914	$ -	$ 1,038,132
7	July	8,649.777	$ 1,109,690	$ (111)	$ -	$ 16,387	$ 1,125,966	$ 2,623	$ 19,279	$ 1,884	$ 24,092	$ -	$ 1,173,843
8	August	8,673.544	$ 1,110,405	$ (112)	$ -	$ 16,680	$ 1,126,974	$ 2,247	$ 20,629	$ 603	$ (28,160)	$ -	$ 1,122,293
9	September	8,047.073	$ 1,035,968	$ (104)	$ -	$ 15,378	$ 1,051,241	$ 1,757	$ 19,279	$ 1,697	$ (12,393)	$ -	$ 1,061,581
10	October	7,076.493	$ 917,178	$ (92)	$ -	$ 13,201	$ 930,287	$ 2,849	$ 19,279	$ 698	$ 50,228	$ -	$ 1,003,342
11	November	7,737.566	$ 974,434	$ (99)	$ -	$ 14,621	$ 988,957	$ 1,983	$ 19,879	$ 5,349	$ 37,136	$ -	$ 1,053,305
12	December	8,094.383	$ 1,086,265	$ (110)	$ 183,735	$ (13,787)	$ 1,256,103	$ 1,987	$ 49,811	$ 5,119	$ 58,629	$ (89,521)	$ 1,282,129
13	Totals	97,019.297	$ 12,607,075	$ (1,270)	$ 183,735	$ 148,188	$ 12,937,729	$ 28,860	$ 266,738	$ 22,899	$ (8,313)	$ (89,521)	$ 13,158,391

Account		
440.0	Residential	7,041,516
440.3	Residential STAS	(702)
442.0	Commercial	4,014,195
442.01	Industrial	1,846,014
442.3	Commercial STAS	(391)
442.31	Industrial STAS	(175)
444.0	Public Street & Highway	19,204
444.3	Public Street & Highway STAS	(2)
447.0	Sales for Resale	18,070
450.0	Forfieted Discounts	28,860
454.0	Rent from Electric Property	266,738
456.0	Other Electric Revenue	22,796
456.1	Other Electric Revenue-STAS	-
456.2	Investment Charge EU	103
495.0	GSSR Over/Under Collections	(8,313)
495.1	Over/Under Collection Unbilled	(89,521)
		13,158,391

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Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026
Expenses By Account and By Type
Year 2013, HY 2024, FTY 2025 and FPFTY 2026

Line	Account	#	Type	Annuals Totals, Detailed by Type 2023	2024	2025	2026
1	PPower-Power Purchases			8,108,800	6,587,193	7,834,837	9,111,330
2	Total Power Purchased			8,108,800	6,587,193	7,834,837	9,111,330
3							
4	580.01-Oper.Superv. Eng-Labor	580	Labor	-	4,043		-
5	580.02-Oper.Superv. Eng-OH	580	OH	-	4,078		-
6	580.03-Oper.Superv. Eng-Transp	580	Trans/Mat				-
7	582.01-Station Exp-Labor	582	Labor				-
8	582.02-Station Exp-OH	582	Trans/Mat	-	-		-
9	583.01-OH Line Exp-Labor	583	Labor	(2,379)	(1,766)	3,980	4,098
10	583.02-OH Line Exp-OH	583	OH	3,064	2,535	1,814	1,922
11	583.05-OH Line Exp-Misc	583	Trans/Mat				-
12	585.01-Street/Signal Light-Labor	585	Labor	-	127	178	182
13	585.02-Street/Signal Light-OH	585	OH	675	19	81	85
14	585.04-Street/Signal Light-Matl	585	Trans/Mat				-
15	586.01-Meter Exp-Labor	586	Labor	19,146	21,287	26,220	26,981
16	586.02-Meter Exp-OH	586	OH	14,498	15,697	11,725	12,422
17	586.03-Meter Exp-Transp	586	Trans/Mat				-
18	586.05-Meter Exp-Misc	586	Other	-	-	500	500
19	587.01-Cust Install Exp-Labor	587	Labor	-	109	178	182
20	587.02-Cust Install Exp-OH	587	OH	-	98	81	85
21	587.04-Cust Install Exp-Matl	587	Trans/Mat				-
22	588.00 Misc Distr Exps	588	Other	1,084	(1,389)	6,800	6,800
23	588.01 Labor - Misc Distr Expens	588	Labor	37,840	29,489	61,875	64,014
24	588.02 OH - Misc Distr Exp	588	OH	48,793	40,264	62,211	62,486
25	588.03-Misc Distr Exp-Transp	588	Trans/Mat				-
26	588.11 Labor - Genl Type Mtg - C	588	Labor	7,872	11,084	8,467	8,766
27	588.12 OH - Genl Type Mtg	588	OH	5,099	8,757	9,349	9,351
28	588.13-Misc Dist Exp-Genl Mtg T	588	Trans/Mat				-
29	588.20-Misc Dist Exp-Outside Tra	588	Other	7,534	9,606	15,000	15,000
30	588.21-Misc Dist Exp-Outside Tra	588	Labor	5,846	10,141	11,506	11,846
31	588.22-Misc Dist Exp-Outside Tra	588	OH	1,559	2,482	5,245	5,556
32	588.23-Misc Dist Exp-Outside Tra	588	Trans/Mat	-	699		-
33	588.31 Labor - On Call - Standby	588	Labor	12,639	12,129	14,799	14,651
34	588.32-Misc Dist Exp-On Call Sta	588	OH	3,575	3,097	6,746	6,873
35	588.40 Safety Mtgs & Training	588	Other	4,268	6,339		-
36	588.41 Labor - Safety Mtgs & Tra	588	Labor	22,120	28,265	39,910	41,188
37	588.42 OH - Safety Mtgs & Tra	588	OH	12,442	12,981	38,515	39,156
38	588.90 Misc Dist-Staking Dept-Tc	588	Other				-
39	589.00-Distr rents	589	Other	30,717	32,950	35,300	35,300
40						-	-
41	**Total operations**			236,392	253,121	360,478	367,446

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Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026
Expenses By Account and By Type
Year 2013, HY 2024, FTY 2025 and FPFTY 2026

Line	Account	#	Type	Annuals Totals, Detailed by Type 2023	2024	2025	2026
42							-
43	590.01-Maint, Supv & Eng-Labor	590	Labor	37,403	41,204	41,076	42,663
44	590.02-Maint, Supv & Eng-OH	590	OH	48,308	56,671	59,695	59,121
45	590.03-Maint, Supv & Eng-Transp	590	Trans/Mat				-
46	591.01-Maint of Structures-Labor	591	Labor	792	-		-
47	591.02-Maint of Structures-OH	591	Trans/Mat	1,056	-		-
48	592.01-Maint of Station Equip-Lal	592	Labor	678	1,255	1,869	1,924
49	592.02-Maint of Station Equip-OH	592	OH	1,863	1,621	2,702	126,752
50	592.03-Maint of Station Equip-Tra	592	Trans/Mat				-
51	592.04- Matl/Supp Inv-Maint Sta	592	Other				(110,119)
52	592.11- Substation Inspect In-hou	592	Labor	3,156	334		-
53	592.00-Substation Insp-In House-	592	Other				-
54	593.00 Maint OH Lines	593	Other				-
55	593.01 Labor - OH Line Maintena	593	Labor	140,138	175,692	202,337	208,333
56	593.02 OH - OH Line Mainten	593	OH	126,049	129,933	101,742	107,224
57	593.03-Maint of OH Lines-Transp	593	Trans/Mat				-
58	593.04 Matl/Supp Inv-Maint Ove	593	Trans/Mat	767	-		-
59	593.10 Maint OH Lines - Brush C	593	Other	407,770	444,468	480,457	480,457
60	593.11 OH Line-Tree Trim-In-H	593	Labor	17,691	15,547	16,743	17,240
61	593.12-Tree Trim-In House-Trans	593	Trans/Mat			7,633	8,087
62	593.13-Tree Trimming-In House-(	593	Labor				-
63	593.21-Overhead Line Inspection	593	Trans/Mat	38,954	6,362	24,679	25,411
64	593.22-OH Line Insp-Line Crew-C	593	OH	8,264	1,470	11,251	11,920
65	593.30 Maint Of OH-Working Off	593	Other				-
66	593.31 Labor - Maint Lines - Worl	593	Labor	355	-		-
67	593.32 OH - Maint Lines - Work C	593	OH	(355)	-		-
68	593.40 Maint Of OH Lines - Meal	593	Other	919	359	1,500	1,500
69	593.50-Maint O/H Line-Major Stor	593	Other	27,765	31,980		-
70	593.51 Labor - Maint Lines - Majo	593	Labor	30,707	26,331	53,377	54,367
71	593.52 OH Lines- Major	593	Other	6,092	4,524	15,216	16,120
72	593.60 Maint Lines-Major Storm-I	593	Labor				-
73	593.80 Maint O/H - Testing-Tools	593	Other	24,438	26,984	40,500	40,500
74	593.90 Maint-Special Equip-Repa	593	Other				-
75	593.91-Special Equip Insp-Labor	593	Labor	7,214	6,137	9,367	9,646
76	593.92-Special Equipment Inspec	593	Trans/Mat			4,270	4,524

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Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026
Expenses By Account and By Type
Year 2013, HY 2024, FTY 2025 and FPFTY 2026

Line	Account	#	Type	Annuals Totals, Detailed by Type 2023	2024	2025	2026
77	594.01-Maint of UG Lines-Labor	594	Labor	1,751	4,369	4,353	4,483
78	594.02-Maint of UG Lines-OH	594	OH	1,588	2,645	1,984	2,102
79	594.03-Maint of UG Lines-Transp	594	Trans/Mat				-
80	594.04-Maint of UG Lines-Matl	594	Trans/Mat				-
81	594.05-Maint UG Lines- Misc	594	Other			-	-
82	594.11- UG Inspect In-hours	594	Labor	1,847	113	150	156
83	594.12- UG Inspect OH	594	OH			69	73
84	594.90- Maint UG Lines PA ON	594	Other	23,250	23,079	33,500	33,500
85	595.01-Maint of Line Xfrnrs-Labor	595	Labor	1,742	3,059	3,347	3,447
86	595.02-Maint of Line Xfrnrs-OH	595	OH	949	1,358	1,526	1,617
87	595.03-Maint of Line Xfrnrs-Trans	595	Trans/Mat				-
88	595.05-Maint Line Xfrnrs-Misc	595	Other				-
89	595.80-Maint of Line Xfrnrs-Disp	595	Trans/Mat	2,987	10,115	3,000	3,000
90	596.01-Maint of Street Lights-Lab	596	Labor	1,700	962	623	641
91	596.02-Maint of Street Lights-OH	596	OH	1,291	650	284	301
92	596.04-Maint of Street Lights-Mat	596	Trans/Mat				-
93	597.00-Maint of Meters	597	Labor	30,912	25,037		-
94	597.01-Maint of Meters-Labor	597	Labor	32,568	31,514	34,412	35,432
95	597.02-Maint of Meters-OH	597	OH	9,842	7,010	15,688	16,620
96	597.03-Maint of Meters-Transp	597	Trans/Mat				-
97	597.04-Maint of Meters-Matl	597	Trans/Mat	(529)	8		-
98	597.05-Maint of Meters-Misc	597	Trans/Mat				-
99	597.41-Maintenance of Meters-T\	597	Labor			623	641
100	597.42-Maintenance of Meters-T\	597	OH			27,484	27,501
101	597.44-Maint TWACS Meters	597	Other	2,674	937	-	-
102							-
103	**Total Maint**			1,042,595	1,081,729	1,201,459	1,235,182
104							
105	**Total Distr Exp**			1,278,988	1,334,849	1,561,937	1,602,629
106				-	-		

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Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026
Expenses By Account and By Type
Year 2013, HY 2024, FTY 2025 and FPFTY 2026

Line	Account	#	Type	Annuals Totals, Detailed by Type 2023	2024	2025	2026
107	**CustS ACCOUNTING & COLLECTING Exp**						-
108	902.01-Meter Reading Exp-Labor	902	Labor	10,767	12,359	10,936	11,261
109	902.02-Meter Reading Exp-OH	902	OH	9,042	9,416	4,986	5,283
110	902.03-Meter Reading Exp-Trans	902	Trans/Mat				-
111	903.00-Cust Rec & Coll Exp	903	Other	5,411	6,868	5,000	5,000
112	903.01-Cust Rec & Collect Exp-L	903	Labor	201,641	203,082	215,355	230,436
113	903.02-Cust Rec & Collect Exp-O	903	OH	260,964	276,153	310,965	317,430
114	903.03-Cust Rec & Collect Exp-T	903	Trans/Mat				-
115	903.20-Cust Rec Exp-Seminars-M	903	Other			500	500
116	903.30-Cust Rec Exp-Postage	903	Other	40,256	43,390	43,375	43,375
117	903.40-Cust Coll-Credit Check	903	Other	858	801	900	900
118	903.45-Cust Coll-EGS Monthly S	903	Other	3,260	4,252	3,600	3,600
119	903.50-Cust Rec Exp-Billing Sup	903	Other	496	1,153	3,200	3,200
120	903.60-Cust Rec Exp-NISC Com	903	Other	128,903	135,388	163,600	163,600
121	903.81-Cust Rec Exp-Collect-Lab	903	Labor	69,880	70,302	75,899	81,136
122	903.82-Cust Rec Exp-Collecting-(	903	OH	88,320	92,349	107,690	109,963
123	903.83-Cust Rec Exp-Collect-Tra	903	Trans/Mat				-
124	903.90-Cust Rec Exp-Delinq	903	Other			500	500
125	903.91-Cust Rec Exp-Delinq-Lab	903	Labor	36,011	36,526	39,266	41,544
126	903.92-Cust Rec Exp-Delinq-OH	903	OH	36,950	37,371	45,181	46,326
127	903.05-Cust Rec Exp-Delinq-Mis	903	Other				-
128	904.00-Uncollectable Accounts	904	Other	-	-	20,000	20,000
129						-	-
130	**Total Cust accounting & collecting**			892,757	929,410	1,050,953	1,084,054
131						**0**	
132	**SALES PROMOTION Exp**						-
133	908.00-Cust Assist-Exp	908	Other	295	-	1,000	1,000
134	908.51-Cust Assist-Energy Audit-	908	Labor	1,735	180	156	161
135	908.52-Cust Assist-Energy Audit-	908	OH			71	76
136	908.05-Cust Assist-Energy Audit-	908	Other				-
137	909.00-Cust Service Info-Misc	909	Other	314	800	16,000	6,000
138	913.00-Advertising Exp	913	Other	1,738	2,191	2,500	2,500
139						-	-
140	**Total Sales Promotion Exp**			4,082	3,171	19,727	9,737
141							-

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Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026
Expenses By Account and By Type
Year 2013, HY 2024, FTY 2025 and FPFTY 2026

Line	Account	#	Type	Annuals Totals, Detailed by Type 2023	2024	2025	2026
142	**ADMINISTRATIVE & Genl Exp**						-
143	920.00-A&G Salaries	920	Labor	22,250	11,954	9,000	9,000
144	920.01-A&G Salaries-Labor	920	Labor	258,765	292,156	325,262	352,797
145	920.02-A&G Salaries-OH	920	OH	351,031	402,852	468,335	484,732
146	920.03-A&G Salaries-Transp	920	Trans/Mat				-
147	920.40-A&G-President-CEO	920	Labor	5,377	6,176	12,000	12,000
148	920.50-A&G-V-P Fin Adminis	920	Labor	8,392	26,510	17,600	15,000
149	920.60-A&G-V-P Eng Oper	920	Labor	2,059	3,188	15,000	15,000
150	920.70-A&G- Staff	920	Labor	4,766	15,065	22,700	22,700
151	921.00-Off Supp & Exp	921	Other	9,054	12,730	11,540	11,540
152	921.10-Off Supp & Exp-Utilities	921	Other	4,803	5,835	6,060	6,060
153	921.40-Off Exp-Subs/Membershi	921	Other	4,042	5,186	3,400	3,400
154	921.50-Off Exp-Off Supp	921	Other	6,413	8,823	23,260	23,260
155	921.60-Off Exp-WECO Telephon	921	Other	31,375	47,437	49,500	49,500
156	921.70-Off Exp-Dispatch Telepho	921	Other	79,441	89,963	90,800	90,800
157	921.90-Off Exp-Misc	921	Other	9,938	8,780	20,060	20,060
158	921.99-Off Exp-Working Capital C	921	Other	(83,141)	(65,853)	(81,613)	(94,910)
159	923.00-Outside Svc Empl	923	Other	26,301	24,421	29,325	29,325
160	923.10-Outside Svc Empl-Auditor	923	Other	31,951	34,886	34,000	34,000
161	923.20-Outside Svc Empl-Engine	923	Other	75	610	5,000	5,000
162	923.30-Outside Svc Empl-Attorne	923	Other	21,703	16,158	25,000	25,000
163	923.90-Outside Services Employe	923	Other	7,859	61,040	61,200	61,200
164	924.00-Property Insurance	924	Other	51,268	53,098	61,410	61,410
165	925.00-Injuries & Damages	925	Other				-
166	926.11-Employee Pen Ben-Healtl	926	OH	-	-		-
167	926.20-Empl Pen Ben-Postret He	926	OH				-
168	926.70-Employee Pen Ben-Life Ir	926	OH				-
169	926.99-Employee Pen Ben-SERF	926	OH				-
170	928.00-Regulatory Commission E	928	Other	32,144	42,985	43,000	43,000
171	928.01-Rate Case Exp	928	Other	36,222	-		110,393
172	930.00-Directors Exp	930	Other	101,167	83,257	95,851	106,681
173	930.11-Misc Gen Exp-GPS Map I	930	Other	-	-		-
174	930.20-Misc Gen Exp-GPS Map-I	930	Labor	3,074	-	3,100	3,100
175	930.21-Misc Gen Exp-GPS Map-(	930	Other				-
176	930.22-Misc Gen Exp-GPS Mapp	930	OH				-
177	930.24-Misc Gen Exp-GPS Mapp	930	Other				-
178	930.25-Misc Gen Exp-Covid Expe	930	Other	-	-		-
179	930.30-Misc Gen Exp- Misc	930	Other	1,113	1,147	800	800

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Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026
Expenses By Account and By Type
Year 2013, HY 2024, FTY 2025 and FPFTY 2026

Line	Account	#	Type	Annuals Totals, Detailed by Type 2023	2024	2025	2026
180	931.00-Rents	931	Other	2,442	3,611	2,200	2,200
181	932.00-Maint of Genl Property	932	Other	48,827	40,021	86,976	86,976
182	932.01-Maint of Genl Property-La	932	Labor	46,719	9,859	10,814	11,135
183	932.02-Maint of Genl Property-Ol	932	OH			4,930	5,223
184	932.10-Maint of Genl Property-Of	932	Other	11,518	6,205	11,000	11,000
185	932.11-Maint Genl Prop-Off Bldg-	932	Labor	3,217	-		-
186	932.12-Maint Genl Prop-Off Bldg-	932	OH				-
187	932.20-Maint Genl-Communicatic	932	Other	-	-	500	500
188	932.21-Maint Genl-Comm Equip-I	932	Labor				-
189	932.22-Maint Genl-Comm Equip-(	932	OH				-
190	932.30-Maint Gen Property-Plant	932	Other	422	12,688	12,550	12,550
191	932.31-Maint Gen Prop-Plant Bld	932	Labor	630	1,505	1,564	1,611
192	932.32-Maint Gen Prop-Plant Bld	932	OH			713	756
193	932.41-Maint Gen Prop-Apt Hous	932	Labor				-
194	932.42-Maint Gen Prop-Apt Hous	932	OH				-
195	932.70-Maint Gen Office Equip	932	Other	1,248	1,908	3,800	3,800
196	932.05-Maint Genl Property- Misc	932	Other	-	-	-	-
197						1,486,637	1,636,599
198	**Total Administrative & Genl Exp**			1,142,464	1,264,200	1,486,637	1,636,599
199	Detail, adjusted for WC Claim						0
200	**Total Operating Exp**			3,318,291	3,531,630	4,119,254	4,333,019
201	From OM			*3,318,291*	*3,531,630*	*4,119,254*	*4,332,745*
202	Adjustments				*='C:\Users\hgorm\Documen*	*='C:\Users\hgorm\Documents Laptop\CTE-25\WEL-25\WEL-2*	
203	Working Capital claim			83,141	65,853	81,613	94,910
204	Rate case Exp			-	-		
205				3,401,431	3,597,484	4,200,867	4,427,928
206	From OM						
207	From C1-1			-	1,294,042		
208	Differrence			3,401,431	2,303,442		
209							
210							
211	Labor		Labor	1,087,018	1,135,323	1,294,042	1,357,763
212	OH		OH	1,033,810	1,109,508	1,301,063	1,460,956
213	Trans/Mat		Trans/Ma	43,235	17,184	39,582	41,022
214	Other		Other	1,154,228	1,269,615	1,484,567	1,473,278
215	WC		WC	-	-	-	-
216				3,318,291	3,531,630	4,119,254	4,333,019

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Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026
Expenses By Account and By Type
Year 2013, HY 2024, FTY 2025 and FPFTY 2026

Line	Account	#	Type	E&O 2025	Office 2025	Admin & Misc 2025	C&T Payroll 2025	Union Payroll 2025	Transportation 2025
1	PPower-Power Purchases								
2	Total Power Purchased								
3									
4	580.01-Oper.Superv. Eng-Labor	580	Labor						
5	580.02-Oper.Superv. Eng-OH	580	OH						
6	580.03-Oper.Superv. Eng-Transp	580	Trans/Mat						
7	582.01-Station Exp-Labor	582	Labor						
8	582.02-Station Exp-OH	582	Trans/Mat						
9	583.01-OH Line Exp-Labor	583	Labor					2,937	1,043
10	583.02-OH Line Exp-OH	583	OH					1,814	
11	583.05-OH Line Exp-Misc	583	Trans/Mat						
12	585.01-Street/Signal Light-Labor	585	Labor					131	47
13	585.02-Street/Signal Light-OH	585	OH					81	
14	585.04-Street/Signal Light-Matl	585	Trans/Mat						
15	586.01-Meter Exp-Labor	586	Labor	500			-	18,979	6,741
16	586.02-Meter Exp-OH	586	OH				-	11,725	
17	586.03-Meter Exp-Transp	586	Trans/Mat						
18	586.05-Meter Exp-Misc	586	Other	500					
19	587.01-Cust Install Exp-Labor	587	Labor				-	131	47
20	587.02-Cust Install Exp-OH	587	OH				-	81	
21	587.04-Cust Install Exp-Matl	587	Trans/Mat						
22	588.00 Misc Distr Exps	588	Other	6,800					
23	588.01 Labor - Misc Distr Expens	588	Labor				34,092	20,501	7,282
24	588.02 OH - Misc Distr Exp	588	OH				49,545	12,666	
25	588.03-Misc Distr Exp-Transp	588	Trans/Mat						
26	588.11 Labor - Genl Type Mtg - C	588	Labor				5,503	2,187	777
27	588.12 OH - Genl Type Mtg	588	OH				7,997	1,352	
28	588.13-Misc Dist Exp-Genl Mtg T	588	Trans/Mat						
29	588.20-Misc Dist Exp-Outside Tra	588	Other	15,000					
30	588.21-Misc Dist Exp-Outside Tra	588	Labor				-	8,490	3,016
31	588.22-Misc Dist Exp-Outside Tra	588	OH				-	5,245	
32	588.23-Misc Dist Exp-Outside Tra	588	Trans/Mat						
33	588.31 Labor - On Call - Standby	588	Labor					10,920	3,879
34	588.32-Misc Dist Exp-On Call Sta	588	OH					6,746	
35	588.40 Safety Mtgs & Training	588	Other						
36	588.41 Labor - Safety Mtgs & Tra	588	Labor				10,698	21,556	7,656
37	588.42 OH - Safety Mtgs & Tra	588	OH	9,650			15,547	13,318	
38	588.90 Misc Dist-Staking Dept-Tc	588	Other						
39	589.00-Distr rents	589	Other	35,300					
40									
41	**Total operations**			67,750	-	-	123,381	138,860	30,487

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Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026
Expenses By Account and By Type
Year 2013, HY 2024, FTY 2025 and FPFTY 2026

Line	Account	#	Type	E&O 2025	Office 2025	Admin & Misc 2025	C&T Payroll 2025	Union Payroll 2025	Transportation 2025
42									
43	590.01-Maint, Supv & Eng-Labor	590	Labor				41,076		
44	590.02-Maint, Supv & Eng-OH	590	OH				59,695		
45	590.03-Maint, Supv & Eng-Transp	590	Trans/Mat						
46	591.01-Maint of Structures-Labor	591	Labor						
47	591.02-Maint of Structures-OH	591	Trans/Mat						
48	592.01-Maint of Station Equip-Lal	592	Labor					1,379	490
49	592.02-Maint of Station Equip-OH	592	OH	1,850				852	
50	592.03-Maint of Station Equip-Tra	592	Trans/Mat						
51	592.04- Matl/Supp Inv-Maint Sta	592	Other						
52	592.11- Substation Inspect In-hou	592	Labor						
53	592.00-Substation Insp-In House-	592	Other						
54	593.00 Maint OH Lines	593	Other						
55	593.01 Labor - OH Line Maintena	593	Labor					149,305	53,032
56	593.02 OH - OH Line Mainten	593	OH	9,500				92,242	
57	593.03-Maint of OH Lines-Transp	593	Trans/Mat						
58	593.04 Matl/Supp Inv-Maint Ove	593	Trans/Mat						
59	593.10 Maint OH Lines - Brush C	593	Other	480,457					
60	593.11 OH Line-Tree Trim-In-H	593	Labor					12,355	4,388
61	593.12-Tree Trim-In House-Trans	593	Trans/Mat					7,633	
62	593.13-Tree Trimming-In House-(	593	Labor						
63	593.21-Overhead Line Inspection	593	Trans/Mat				-	18,211	6,468
64	593.22-OH Line Insp-Line Crew-C	593	OH				-	11,251	
65	593.30 Maint Of OH-Working Off	593	Other						
66	593.31 Labor - Maint Lines - Worl	593	Labor						
67	593.32 OH - Maint Lines - Work (	593	OH						
68	593.40 Maint Of OH Lines - Meal	593	Other	1,500					
69	593.50-Maint O/H Line-Major Sto	593	Other						
70	593.51 Labor - Maint Lines - Majo	593	Labor	20,000			-	24,629	8,748
71	593.52 OH Lines- Major	593	Other				-	15,216	
72	593.60 Maint Lines-Major Storm-I	593	Labor						
73	593.80 Maint O/H - Testing-Tools	593	Other	40,500					
74	593.90 Maint-Special Equip-Repa	593	Other						
75	593.91-Special Equip Insp-Labor	593	Labor					6,912	2,455
76	593.92-Special Equipment Inspec	593	Trans/Mat					4,270	

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Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026
Expenses By Account and By Type
Year 2013, HY 2024, FTY 2025 and FPFTY 2026

Line	Account	#	Type	E&O 2025	Office 2025	Admin & Misc 2025	C&T Payroll 2025	Union Payroll 2025	Transportation 2025
77	594.01-Maint of UG Lines-Labor	594	Labor				-	3,212	1,141
78	594.02-Maint of UG Lines-OH	594	OH				-	1,984	
79	594.03-Maint of UG Lines-Transp	594	Trans/Mat						
80	594.04-Maint of UG Lines-Matl	594	Trans/Mat						
81	594.05-Maint UG Lines- Misc	594	Other						
82	594.11- UG Inspect In-hours	594	Labor					111	39
83	594.12- UG Inspect OH	594	OH					69	
84	594.90- Maint UG Lines PA ON	594	Other	33,500					
85	595.01-Maint of Line Xfrnrs-Labor	595	Labor					2,470	877
86	595.02-Maint of Line Xfrnrs-OH	595	OH					1,526	
87	595.03-Maint of Line Xfrnrs-Trans	595	Trans/Mat						
88	595.05-Maint Line Xfrnrs-Misc	595	Other						
89	595.80-Maint of Line Xfrnrs-Disp	595	Trans/Mat	3,000					
90	596.01-Maint of Street Lights-Lab	596	Labor					460	163
91	596.02-Maint of Street Lights-OH	596	OH					284	
92	596.04-Maint of Street Lights-Mat	596	Trans/Mat						
93	597.00-Maint of Meters	597	Labor						
94	597.01-Maint of Meters-Labor	597	Labor					25,393	9,019
95	597.02-Maint of Meters-OH	597	OH					15,688	
96	597.03-Maint of Meters-Transp	597	Trans/Mat						
97	597.04-Maint of Meters-Matl	597	Trans/Mat						
98	597.05-Maint of Meters-Misc	597	Trans/Mat						
99	597.41-Maintenance of Meters-T\	597	Labor					460	163
100	597.42-Maintenance of Meters-T\	597	OH	27,200				284	
101	597.44-Maint TWACS Meters	597	Other						
102									
103	**Total Maint**			617,507	-	-	100,771	396,196	86,985
104									
105	**Total Distr Exp**			685,257	-	-	224,153	535,056	117,471
106									

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Wellsboro Electric Company
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Expenses By Account and By Type
Year 2013, HY 2024, FTY 2025 and FPFTY 2026

Line	Account	#	Type	E&O 2025	Office 2025	Admin & Misc 2025	C&T Payroll 2025	Union Payroll 2025	Transportation 2025
107	**CustS ACCOUNTING & COLLECTING Exp**								
108	902.01-Meter Reading Exp-Labor	902	Labor					8,070	2,866
109	902.02-Meter Reading Exp-OH	902	OH					4,986	
110	902.03-Meter Reading Exp-Trans	902	Trans/Mat						
111	903.00-Cust Rec & Coll Exp	903	Other			5,000			
112	903.01-Cust Rec & Collect Exp-La	903	Labor				213,345	1,483	527
113	903.02-Cust Rec & Collect Exp-O	903	OH				310,049	916	
114	903.03-Cust Rec & Collect Exp-Tr	903	Trans/Mat						
115	903.20-Cust Rec Exp-Seminars-M	903	Other		500				
116	903.30-Cust Rec Exp-Postage	903	Other		43,375				
117	903.40-Cust Coll-Credit Check	903	Other		900				
118	903.45-Cust Coll-EGS Monthly Sv	903	Other		3,600				
119	903.50-Cust Rec Exp-Billing Supp	903	Other		3,200				
120	903.60-Cust Rec Exp-NISC Comp	903	Other	8,500	155,100				
121	903.81-Cust Rec Exp-Collect-Lab	903	Labor				73,281	1,932	686
122	903.82-Cust Rec Exp-Collecting-(	903	OH				106,497	1,193	
123	903.83-Cust Rec Exp-Collect-Tra	903	Trans/Mat						
124	903.90-Cust Rec Exp-Delinq	903	Other		500				
125	903.91-Cust Rec Exp-Delinq-Labo	903	Labor				27,351	8,792	3,123
126	903.92-Cust Rec Exp-Delinq-OH	903	OH				39,749	5,432	
127	903.05-Cust Rec Exp-Delinq-Misc	903	Other						
128	904.00-Uncollectable Accounts	904	Other		20,000				
129									
130	**Total Cust accounting & collecting**			8,500	227,175	5,000	770,272	32,804	7,202
131									
132	**SALES PROMOTION Exp**								
133	908.00-Cust Assist-Exp	908	Other		1,000				
134	908.51-Cust Assist-Energy Audit-	908	Labor					115	41
135	908.52-Cust Assist-Energy Audit-	908	OH					71	
136	908.05-Cust Assist-Energy Audit-	908	Other						
137	909.00-Cust Service Info-Misc	909	Other		16,000				
138	913.00-Advertising Exp	913	Other		2,500				
139									
140	**Total Sales Promotion Exp**			-	19,500	-	-	186	41
141									

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Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026
Expenses By Account and By Type
Year 2013, HY 2024, FTY 2025 and FPFTY 2026

Line	Account	#	Type	E&O 2025	Office 2025	Admin & Misc 2025	C&T Payroll 2025	Union Payroll 2025	Transportation 2025
142	**ADMINISTRATIVE & Genl Exp**								
143	920.00-A&G Salaries	920	Labor			9,000			
144	920.01-A&G Salaries-Labor	920	Labor				322,262		3,000
145	920.02-A&G Salaries-OH	920	OH				468,335		
146	920.03-A&G Salaries-Transp	920	Trans/Mat						
147	920.40-A&G-President-CEO	920	Labor	12,000					
148	920.50-A&G-V-P Fin Adminis	920	Labor			17,600			
149	920.60-A&G-V-P Eng Oper	920	Labor	15,000					
150	920.70-A&G- Staff	920	Labor		22,700				
151	921.00-Off Supp & Exp	921	Other		5,540	6,000			
152	921.10-Off Supp & Exp-Utilities	921	Other			6,060			
153	921.40-Off Exp-Subs/Membershi	921	Other		3,400				
154	921.50-Off Exp-Off Supp	921	Other		23,260				
155	921.60-Off Exp-WECO Telephon	921	Other	-		49,500			
156	921.70-Off Exp-Dispatch Telepho	921	Other	86,000		4,800			
157	921.90-Off Exp-Misc	921	Other		17,700	2,360			
158	921.99-Off Exp-Working Capital (	921	Other			(81,613)			
159	923.00-Outside Svc Empl	923	Other		3,925	25,400			
160	923.10-Outside Svc Empl-Auditor	923	Other			34,000			
161	923.20-Outside Svc Empl-Engine	923	Other	5,000					
162	923.30-Outside Svc Empl-Attorne	923	Other			25,000			
163	923.90-Outside Services Employ	923	Other			61,200			
164	924.00-Property Insurance	924	Other			61,410			
165	925.00-Injuries & Damages	925	Other						
166	926.11-Employee Pen Ben-Healt	926	OH						
167	926.20-Empl Pen Ben-Postret He	926	OH						
168	926.70-Employee Pen Ben-Life In	926	OH						
169	926.99-Employee Pen Ben-SERP	926	OH						
170	928.00-Regulatory Commission E	928	Other			43,000			
171	928.01-Rate Case Exp	928	Other						
172	930.00-Directors Exp	930	Other			95,851			
173	930.11-Misc Gen Exp-GPS Map I	930	Other						
174	930.20-Misc Gen Exp-GPS Map-I	930	Labor	3,100					
175	930.21-Misc Gen Exp-GPS Map-(	930	Other						
176	930.22-Misc Gen Exp-GPS Mapp	930	OH						
177	930.24-Misc Gen Exp-GPS Mapp	930	Other						
178	930.25-Misc Gen Exp-Covid Expe	930	Other						
179	930.30-Misc Gen Exp- Misc	930	Other	800					

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Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026
Expenses By Account and By Type
Year 2013, HY 2024, FTY 2025 and FPFTY 2026

Line	Account	#	Type	E&O 2025	Office 2025	Admin & Misc 2025	C&T Payroll 2025	Union Payroll 2025	Transportation 2025
180	931.00-Rents	931	Other		2,200				
181	932.00-Maint of Genl Property	932	Other	11,500		75,476			
182	932.01-Maint of Genl Property-La	932	Labor					7,980	2,834
183	932.02-Maint of Genl Property-Ol	932	OH					4,930	
184	932.10-Maint of Genl Property-Of	932	Other	11,000					
185	932.11-Maint Genl Prop-Off Bldg-	932	Labor						
186	932.12-Maint Genl Prop-Off Bldg-	932	OH						
187	932.20-Maint Genl-Communicatic	932	Other	500					
188	932.21-Maint Genl-Comm Equip-I	932	Labor						
189	932.22-Maint Genl-Comm Equip-(	932	OH						
190	932.30-Maint Gen Property-Plant	932	Other	12,550			-		
191	932.31-Maint Gen Prop-Plant Bld	932	Labor					1,154	410
192	932.32-Maint Gen Prop-Plant Bld	932	OH					713	
193	932.41-Maint Gen Prop-Apt Hous	932	Labor						
194	932.42-Maint Gen Prop-Apt Hous	932	OH						
195	932.70-Maint Gen Office Equip	932	Other		3,800				
196	932.05-Maint Genl Property- Misc	932	Other						
197				157,450	82,525	435,044	790,597	14,777	6,244
198	**Total Administrative & Genl Exp**			157,450	82,525	435,044	790,597	14,777	6,244
199	Detail, adjusted for WC Claim								
200	**Total Operating Exp**			851,207	329,200	440,044	1,785,022	582,823	130,959
201	From OM								
202	Adjustments			*'5 Support\[WEL25 OpBudget2025.xlsx]Assumptions-Breakdown-All'!$I$357*					
203	Working Capital claim								
204	Rate case Exp								
205				851,207	329,200	440,044	1,785,022	582,823	130,959
206	From OM								
207	From C1-1								
208	Differrence								
209									
210									
211	Labor		Labor	50,600	22,700	26,600	727,608	342,044	124,490
212	OH		OH	48,200	-	-	1,057,414	195,449	-
213	Trans/Mat		Trans/Ma	3,000	-	-	-	30,114	6,468
214	Other		Other	749,407	306,500	413,444	-	15,216	-
215	WC		WC	-	-	-	-	-	-
216				851,207	329,200	440,044	1,785,022	582,823	130,959

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Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026
Expenses By Account and By Type
Year 2013, HY 2024, FTY 2025 and FPFTY 2026

Line	Account	#	Type	E&O 2026	Office 2026	Admin & Misc 2026	C&T Payroll 2026	Union Payroll 2026	Transportation 2026	Annual Totals, By Account 2023	2024	2025	2026
1	PPower-Power Purchases									8,108,800	6,587,193	7,834,837	9,111,330
2	Total Power Purchased									8,108,800	6,587,193	7,834,837	9,111,330
3													
4	580.01-Oper.Superv. Eng-Labor	580	Labor										
5	580.02-Oper.Superv. Eng-OH	580	OH										
6	580.03-Oper.Superv. Eng-Transp	580	Trans/Mat							-	8,121	-	-
7	582.01-Station Exp-Labor	582	Labor										
8	582.02-Station Exp-OH	582	Trans/Mat							-	-	-	-
9	583.01-OH Line Exp-Labor	583	Labor					3,054	1,044				
10	583.02-OH Line Exp-OH	583	OH					1,922					
11	583.05-OH Line Exp-Misc	583	Trans/Mat							686	770	5,794	6,020
12	585.01-Street/Signal Light-Labor	585	Labor					136	46				
13	585.02-Street/Signal Light-OH	585	OH					85					
14	585.04-Street/Signal Light-Matl	585	Trans/Mat							675	146	259	267
15	586.01-Meter Exp-Labor	586	Labor	500			-	19,737	6,744				
16	586.02-Meter Exp-OH	586	OH				-	12,422					
17	586.03-Meter Exp-Transp	586	Trans/Mat										
18	586.05-Meter Exp-Misc	586	Other	500						33,644	36,983	38,445	39,903
19	587.01-Cust Install Exp-Labor	587	Labor				-	136	46				
20	587.02-Cust Install Exp-OH	587	OH				-	85					
21	587.04-Cust Install Exp-Matl	587	Trans/Mat							-	206	259	267
22	588.00 Misc Distr Exps	588	Other	6,800									
23	588.01 Labor - Misc Distr Expens	588	Labor				35,409	21,320	7,285				
24	588.02 OH - Misc Distr Exp	588	OH				49,068	13,418					
25	588.03-Misc Distr Exp-Transp	588	Trans/Mat										
26	588.11 Labor - Genl Type Mtg - C	588	Labor				5,715	2,274	777				
27	588.12 OH - Genl Type Mtg	588	OH				7,920	1,431					
28	588.13-Misc Dist Exp-Genl Mtg T	588	Trans/Mat										
29	588.20-Misc Dist Exp-Outside Tra	588	Other	15,000									
30	588.21-Misc Dist Exp-Outside Tra	588	Labor				-	8,829	3,017				
31	588.22-Misc Dist Exp-Outside Tra	588	OH				-	5,556					
32	588.23-Misc Dist Exp-Outside Tra	588	Trans/Mat										
33	588.31 Labor - On Call - Standby	588	Labor					10,920	3,731				
34	588.32-Misc Dist Exp-On Call Sta	588	OH					6,873					
35	588.40 Safety Mtgs & Training	588	Other										
36	588.41 Labor - Safety Mtgs & Tra	588	Labor				11,111	22,417	7,660				
37	588.42 OH - Safety Mtgs & Tra	588	OH	9,650			15,397	14,109					
38	588.90 Misc Dist-Staking Dept-Tc	588	Other							170,671	173,944	280,422	285,688
39	589.00-Distr rents	589	Other	35,300						30,717	32,950	35,300	35,300
40													
41	**Total operations**			67,750	-	-	124,621	144,724	30,352	236,392	253,121	360,478	367,446

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Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026
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Year 2013, HY 2024, FTY 2025 and FPFTY 2026

Line	Account	#	Type	E&O 2026	Office 2026	Admin & Misc 2026	C&T Payroll 2026	Union Payroll 2026	Transportation 2026	Annual Totals, By Account 2023	2024	2025	2026
42													
43	590.01-Maint, Supv & Eng-Labor	590	Labor				42,663						
44	590.02-Maint, Supv & Eng-OH	590	OH				59,121						
45	590.03-Maint, Supv & Eng-Transp	590	Trans/Mat							85,710	97,875	100,771	101,784
46	591.01-Maint of Structures-Labor	591	Labor										
47	591.02-Maint of Structures-OH	591	Trans/Mat							1,848	-	-	-
48	592.01-Maint of Station Equip-Lal	592	Labor					1,434	490				
49	592.02-Maint of Station Equip-OH	592	OH	125,850				902					
50	592.03-Maint of Station Equip-Tra	592	Trans/Mat										
51	592.04- Matl/Supp Inv-Maint Sta	592	Other	(110,119)									
52	592.11- Substation Inspect In-hou	592	Labor										
53	592.00-Substation Insp-In House-	592	Other							5,697	3,210	4,571	18,557
54	593.00 Maint OH Lines	593	Other										
55	593.01 Labor - OH Line Maintena	593	Labor					155,274	53,059				
56	593.02 OH - OH Line Mainten	593	OH	9,500				97,724					
57	593.03-Maint of OH Lines-Transp	593	Trans/Mat										
58	593.04 Matl/Supp Inv-Maint Ove	593	Trans/Mat										
59	593.10 Maint OH Lines - Brush C	593	Other	480,457									
60	593.11 OH Line-Tree Trim-In-H	593	Labor					12,849	4,391				
61	593.12-Tree Trim-In House-Trans	593	Trans/Mat					8,087					
62	593.13-Tree Trimming-In House-(	593	Labor										
63	593.21-Overhead Line Inspection	593	Trans/Mat				-	18,939	6,472				
64	593.22-OH Line Insp-Line Crew-C	593	OH				-	11,920					
65	593.30 Maint Of OH-Working Off	593	Other										
66	593.31 Labor - Maint Lines - Wor	593	Labor										
67	593.32 OH - Maint Lines - Work (	593	OH										
68	593.40 Maint Of OH Lines - Meal	593	Other	1,500									
69	593.50-Maint O/H Line-Major Sto	593	Other										
70	593.51 Labor - Maint Lines - Majo	593	Labor	20,000			-	25,614	8,753				
71	593.52 OH Lines- Major	593	Other				-	16,120					
72	593.60 Maint Lines-Major Storm-I	593	Labor										
73	593.80 Maint O/H - Testing-Tools	593	Other	40,500									
74	593.90 Maint-Special Equip-Repa	593	Other										
75	593.91-Special Equip Insp-Labor	593	Labor					7,189	2,457				
76	593.92-Special Equipment Inspec	593	Trans/Mat					4,524		836,769	869,788	969,072	985,327

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Year 2013, HY 2024, FTY 2025 and FPFTY 2026

Line	Account	#	Type	E&O 2026	Office 2026	Admin & Misc 2026	C&T Payroll 2026	Union Payroll 2026	Transportation 2026	Annual Totals, By Account 2023	2024	2025	2026
77	594.01-Maint of UG Lines-Labor	594	Labor				-	3,341	1,142				
78	594.02-Maint of UG Lines-OH	594	OH				-	2,102					
79	594.03-Maint of UG Lines-Transp	594	Trans/Mat										
80	594.04-Maint of UG Lines-Matl	594	Trans/Mat										
81	594.05-Maint UG Lines- Misc	594	Other										
82	594.11- UG Inspect In-hours	594	Labor					116	40				
83	594.12- UG Inspect OH	594	OH					73					
84	594.90- Maint UG Lines PA ON	594	Other	33,500						28,436	30,206	40,056	40,313
85	595.01-Maint of Line Xfrnrs-Labor	595	Labor					2,569	878				
86	595.02-Maint of Line Xfrnrs-OH	595	OH					1,617					
87	595.03-Maint of Line Xfrnrs-Trans	595	Trans/Mat										
88	595.05-Maint Line Xfrnrs-Misc	595	Other										
89	595.80-Maint of Line Xfrnrs-Disp	595	Trans/Mat	3,000						5,677	14,532	7,873	8,064
90	596.01-Maint of Street Lights-Lab	596	Labor					478	163				
91	596.02-Maint of Street Lights-OH	596	OH					301					
92	596.04-Maint of Street Lights-Mat	596	Trans/Mat							2,991	1,612	907	942
93	597.00-Maint of Meters	597	Labor										
94	597.01-Maint of Meters-Labor	597	Labor					26,408	9,024				
95	597.02-Maint of Meters-OH	597	OH					16,620					
96	597.03-Maint of Meters-Transp	597	Trans/Mat										
97	597.04-Maint of Meters-Matl	597	Trans/Mat										
98	597.05-Maint of Meters-Misc	597	Trans/Mat										
99	597.41-Maintenance of Meters-T\	597	Labor					478	163				
100	597.42-Maintenance of Meters-T\	597	OH	27,200				301					
101	597.44-Maint TWACS Meters	597	Other							75,467	64,505	78,208	80,194
102													
103	**Total Maint**			631,388	-	-	101,784	414,980	87,030	1,042,595	1,081,729	1,201,459	1,235,182
104													
105	**Total Distr Exp**			699,138	-	-	226,405	559,704	117,381	1,278,988	1,334,849	1,561,937	1,602,629
106													

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Year 2013, HY 2024, FTY 2025 and FPFTY 2026

Line	Account	#	Type	E&O 2026	Office 2026	Admin & Misc 2026	C&T Payroll 2026	Union Payroll 2026	Transportation 2026	Annual Totals, By Account 2023	2024	2025	2026
107	**CustS ACCOUNTING & COLLECTING Exp**												
108	902.01-Meter Reading Exp-Labor	902	Labor					8,393	2,868				
109	902.02-Meter Reading Exp-OH	902	OH					5,283					
110	902.03-Meter Reading Exp-Trans	902	Trans/Mat							19,808	21,775	15,922	16,544
111	903.00-Cust Rec & Coll Exp	903	Other			5,000							
112	903.01-Cust Rec & Collect Exp-L	903	Labor				228,366	1,543	527				
113	903.02-Cust Rec & Collect Exp-O	903	OH				316,458	972					
114	903.03-Cust Rec & Collect Exp-T	903	Trans/Mat										
115	903.20-Cust Rec Exp-Seminars-M	903	Other		500								
116	903.30-Cust Rec Exp-Postage	903	Other		43,375								
117	903.40-Cust Coll-Credit Check	903	Other		900								
118	903.45-Cust Coll-EGS Monthly S	903	Other		3,600								
119	903.50-Cust Rec Exp-Billing Supp	903	Other		3,200								
120	903.60-Cust Rec Exp-NISC Comp	903	Other	8,500	155,100								
121	903.81-Cust Rec Exp-Collect-Lab	903	Labor				78,440	2,009	686				
122	903.82-Cust Rec Exp-Collecting-(	903	OH				108,698	1,265					
123	903.83-Cust Rec Exp-Collect-Tra	903	Trans/Mat										
124	903.90-Cust Rec Exp-Delinq	903	Other		500								
125	903.91-Cust Rec Exp-Delinq-Lab	903	Labor				29,277	9,143	3,124				
126	903.92-Cust Rec Exp-Delinq-OH	903	OH				40,571	5,755					
127	903.05-Cust Rec Exp-Delinq-Misc	903	Other							872,949	907,634	1,015,031	1,047,510
128	904.00-Uncollectable Accounts	904	Other		20,000					-	-	20,000	20,000
129													
130	**Total Cust accounting & collecting**			8,500	227,175	5,000	801,810	34,363	7,206	892,757	929,410	1,050,953	1,084,054
131													
132	**SALES PROMOTION Exp**												
133	908.00-Cust Assist-Exp	908	Other		1,000								
134	908.51-Cust Assist-Energy Audit-	908	Labor					120	41				
135	908.52-Cust Assist-Energy Audit-	908	OH					76					
136	908.05-Cust Assist-Energy Audit-	908	Other							2,030	180	1,227	1,237
137	909.00-Cust Service Info-Misc	909	Other		6,000					314	800	16,000	6,000
138	913.00-Advertising Exp	913	Other		2,500					1,738	2,191	2,500	2,500
139													
140	**Total Sales Promotion Exp**			-	9,500	-	-	196	41	4,082	3,171	19,727	9,737
141													

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Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026
Expenses By Account and By Type
Year 2013, HY 2024, FTY 2025 and FPFTY 2026

Line	Account	#	Type	E&O 2026	Office 2026	Admin & Misc 2026	C&T Payroll 2026	Union Payroll 2026	Transportation 2026	Annual Totals, By Account 2023	2024	2025	2026
142	**ADMINISTRATIVE & Genl Exp**												
143	920.00-A&G Salaries	920	Labor			9,000							
144	920.01-A&G Salaries-Labor	920	Labor				349,797		3,000				
145	920.02-A&G Salaries-OH	920	OH				484,732						
146	920.03-A&G Salaries-Transp	920	Trans/Mat										
147	920.40-A&G-President-CEO	920	Labor	12,000									
148	920.50-A&G-V-P Fin Adminis	920	Labor			15,000							
149	920.60-A&G-V-P Eng Oper	920	Labor	15,000									
150	920.70-A&G- Staff	920	Labor		22,700					652,639	757,901	869,897	911,229
151	921.00-Off Supp & Exp	921	Other		5,540	6,000							
152	921.10-Off Supp & Exp-Utilities	921	Other			6,060							
153	921.40-Off Exp-Subs/Membershi	921	Other		3,400								
154	921.50-Off Exp-Off Supp	921	Other		23,260								
155	921.60-Off Exp-WECO Telephon	921	Other	-		49,500							
156	921.70-Off Exp-Dispatch Telepho	921	Other	86,000		4,800							
157	921.90-Off Exp-Misc	921	Other		17,700	2,360							
158	921.99-Off Exp-Working Capital (	921	Other			(94,910)				61,925	112,900	123,007	109,710
159	923.00-Outside Svc Empl	923	Other		3,925	25,400							
160	923.10-Outside Svc Empl-Auditor	923	Other			34,000							
161	923.20-Outside Svc Empl-Engine	923	Other	5,000									
162	923.30-Outside Svc Empl-Attorne	923	Other			25,000							
163	923.90-Outside Services Employ	923	Other			61,200				87,889	137,115	154,525	154,525
164	924.00-Property Insurance	924	Other			61,410				51,268	53,098	61,410	61,410
165	925.00-Injuries & Damages	925	Other							-	-	-	-
166	926.11-Employee Pen Ben-Healt	926	OH										
167	926.20-Empl Pen Ben-Postret He	926	OH										
168	926.70-Employee Pen Ben-Life Ir	926	OH										
169	926.99-Employee Pen Ben-SERF	926	OH							-	-	-	-
170	928.00-Regulatory Commission E	928	Other			43,000							
171	928.01-Rate Case Exp	928	Other			110,393				68,366	42,985	43,000	153,393
172	930.00-Directors Exp	930	Other			106,681							
173	930.11-Misc Gen Exp-GPS Map I	930	Other										
174	930.20-Misc Gen Exp-GPS Map-I	930	Labor	3,100									
175	930.21-Misc Gen Exp-GPS Map-(	930	Other										
176	930.22-Misc Gen Exp-GPS Mapp	930	OH										
177	930.24-Misc Gen Exp-GPS Mapp	930	Other										
178	930.25-Misc Gen Exp-Covid Exp	930	Other										
179	930.30-Misc Gen Exp- Misc	930	Other	800						105,355	84,404	99,751	110,581

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Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026
Expenses By Account and By Type
Year 2013, HY 2024, FTY 2025 and FPFTY 2026

Line	Account	#	Type	E&O 2026	Office 2026	Admin & Misc 2026	C&T Payroll 2026	Union Payroll 2026	Transportation 2026	Annual Totals, By Account 2023	2024	2025	2026
180	931.00-Rents	931	Other		2,200					2,442	3,611	2,200	2,200
181	932.00-Maint of Genl Property	932	Other	11,500		75,476							
182	932.01-Maint of Genl Property-La	932	Labor					8,299	2,836				
183	932.02-Maint of Genl Property-Ol	932	OH					5,223					
184	932.10-Maint of Genl Property-Of	932	Other	11,000									
185	932.11-Maint Genl Prop-Off Bldg-	932	Labor										
186	932.12-Maint Genl Prop-Off Bldg-	932	OH										
187	932.20-Maint Genl-Communicatic	932	Other	500									
188	932.21-Maint Genl-Comm Equip-I	932	Labor										
189	932.22-Maint Genl-Comm Equip-(	932	OH										
190	932.30-Maint Gen Property-Plant	932	Other	12,550			-						
191	932.31-Maint Gen Prop-Plant Bld	932	Labor					1,201	410				
192	932.32-Maint Gen Prop-Plant Bld	932	OH					756					
193	932.41-Maint Gen Prop-Apt Hous	932	Labor										
194	932.42-Maint Gen Prop-Apt Hous	932	OH										
195	932.70-Maint Gen Office Equip	932	Other		3,800								
196	932.05-Maint Genl Property- Misc	932	Other							112,580	72,186	132,847	133,551
197				157,450	82,525	540,370	834,529	15,479	6,246				
198	**Total Administrative & Genl Exp**			157,450	82,525	540,370	834,529	15,479	6,246	1,142,464	1,264,200	1,486,637	1,636,599
199	Detail, adjusted for WC Claim												
200	**Total Operating Exp**			865,088	319,200	545,370	1,862,744	609,742	130,875	3,318,291	3,531,630	4,119,254	4,333,019
201	From OM									0	0	0	0
202	Adjustments												
203	Working Capital claim												
204	Rate case Exp												
205				865,088	319,200	545,370	1,862,744	609,742	130,875				
206	From OM												
207	From C1-1												
208	Differrence												
209													
210													
211	Labor		Labor	50,600	22,700	24,000	780,779	355,281	124,403				
212	OH		OH	172,200	-	-	1,081,965	206,791	-				
213	Trans/Mat		Trans/Ma	3,000	-	-	-	31,550	6,472				
214	Other		Other	639,288	296,500	521,370	-	16,120	-				
215	WC		WC	-	-	-	-	-	-				
216				865,088	319,200	545,370	1,862,744	609,742	130,875				

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Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026
Expenses By Account
Year 2013, HY 2024, FTY 2025 and FPFTY 2026

Line	Acct.	Account Description	Labor 12/31/23	Labor 12/31/24	Labor 12/31/25	Labor 12/31/26	OH 12/31/23	OH 12/31/24	OH 12/31/25	OH 12/31/26
1		Other Power Supply Expenses:								
2	555	Power Purchased	$0	$0	$0	$0	$0	$0	$0	$0
3		*Total Other Power Supply Expenses*	0	0	0	0	0	0	0	0
4										
5		Distribution Expenses								
6	580	Operations Supv & Eng	0	4,043	0	0	0	4,078	0	0
7	582	Station Expense	0	0	0	0	0	0	0	0
8	583	Overhead Line Expense	(2,379)	(1,766)	3,980	4,098	3,064	2,535	1,814	1,922
9	585	Street Lighting Expense	0	127	178	182	675	19	81	85
10	586	Meter Expense	19,146	21,287	26,220	26,981	14,498	15,697	11,725	12,422
11	587	Customer Installation Expense	0	109	178	182	0	98	81	85
12	588	Miscellaneous Distribution Expense	86,318	91,107	136,556	140,466	71,468	67,581	122,066	123,422
13	589	Rents	0	0	0	0	0	0	0	0
14		*Total Operation*	103,085	114,906	167,111	171,910	89,705	90,009	135,767	137,936
15										
16	590	Maint Supv & Eng	37,403	41,204	41,076	42,663	48,308	56,671	59,695	59,121
17	591	Maintenance of Structures	792	0	0	0	0	0	0	0
18	592	Maintenance of Station Equipment	3,834	1,589	1,869	1,924	1,863	1,621	2,702	126,752
19	593	Maintenance of Overhead Lines	196,105	223,708	281,824	289,584	133,958	131,403	112,993	119,144
20	594	Maintenance of Underground Lines	3,598	4,482	4,503	4,638	1,588	2,645	2,053	2,175
21	595	Maintain Line Transformers	1,742	3,059	3,347	3,447	949	1,358	1,526	1,617
22	596	Maint. Street Light & Signal Expense	1,700	962	623	641	1,291	650	284	301
23	597	Maintenance of Misc. Distribution Plai	63,480	56,551	35,036	36,073	9,842	7,010	43,172	44,121
24		*Total Maintenance*	308,653	331,556	368,279	378,972	197,799	201,357	222,425	353,231
25		*Total Distribution Expenses*	411,738	446,462	535,390	550,882	287,504	291,366	358,192	491,167
26										
27		Customer Accounting & Collection Expenses:								
28	902	Meter Reading Expense	10,767	12,359	10,936	11,261	9,042	9,416	4,986	5,283
29	903	Customer Records & Collection Exp	307,531	309,910	330,520	353,116	386,234	405,873	463,836	473,719
30	904	Uncollectible Accounts	0	0	0	0	0	0	0	0
31		*Total Customer Accounting & Collecti*	318,298	322,269	341,456	364,377	395,275	415,289	468,822	479,002
32										
33	908	Cust Assist-Energy Audit-Misc	1,735	180	156	161	0	0	71	76
34	909	Cust Service Info-Misc	0	0	0	0	0	0	0	0
35	913	Advertising Exp	0	0	0	0	0	0	0	0
36	908-913	Safety and Communications	1,735	180	156	161	0	0	71	76
37										

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Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026
Expenses By Account
Year 2013, HY 2024, FTY 2025 and FPFTY 2026

Line	Acct.	Account Description	Labor 12/31/23	Labor 12/31/24	Labor 12/31/25	Labor 12/31/26	OH 12/31/23	OH 12/31/24	OH 12/31/25	OH 12/31/26
38	Administrative & General Expenses:									
39	920	Administrative & General Salaries	301,608	355,049	401,562	426,497	351,031	402,852	468,335	484,732
40	921	Office Supplies & Expenses	0	0	0	0	0	0	0	0
41	923	Outside Services Employed	0	0	0	0	0	0	0	0
42	924	Property Insurance	0	0	0	0	0	0	0	0
43	926	Employee Pensions & Benefits	0	0	0	0	0	0	0	0
44	928	Regulatory commission expenses	0	0	0	0	0	0	0	0
45	930	Miscellaneous General Expense	3,074	0	3,100	3,100	0	0	0	0
46	931	Rents	0	0	0	0	0	0	0	0
47	932	Maintenance of general plant	50,565	11,364	12,378	12,746	0	0	5,643	5,979
48		*Total Administrative & General Expen*	355,248	366,413	417,040	442,344	351,031	402,852	473,978	490,711
49										
50		**Total Operating & Maintenance Ex**	**$1,087,018**	**$1,135,323**	**$1,294,042**	**$1,357,763**	**$1,033,810**	**$1,109,508**	**$1,301,063**	**$1,460,956**

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Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026
Expenses By Account
Year 2013, HY 2024, FTY 2025 and FPFTY 2026

Line	Acct.	Account Description	Trans/Mat 12/31/23	Trans/Mat 12/31/24	Trans/Mat 12/31/25	Trans/Mat 12/31/26	Other 12/31/23	Other 12/31/24	Other 12/31/25	Other 12/31/26	Total 12/31/23	Total 12/31/24	Total 12/31/25	Total 12/31/26
1		Other Power Supply Expenses:												
2	555	Power Purchased	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
3		*Total Other Power Supply Expenses*	0	0	0	0	0	0	0	0	0	0	0	0
4														
5		Distribution Expenses												
6	580	Operations Supv & Eng	0	0	0	0	0	0	0	0	0	8,121	0	0
7	582	Station Expense	0	0	0	0	0	0	0	0	0	0	0	0
8	583	Overhead Line Expense	0	0	0	0	0	0	0	0	686	770	5,794	6,020
9	585	Street Lighting Expense	0	0	0	0	0	0	0	0	675	146	259	267
10	586	Meter Expense	0	0	0	0	0	0	500	500	33,644	36,983	38,445	39,903
11	587	Customer Installation Expense	0	0	0	0	0	0	0	0	0	206	259	267
12	588	Miscellaneous Distribution Expense	0	699	0	0	12,886	14,556	21,800	21,800	170,671	173,944	280,422	285,688
13	589	Rents	0	0	0	0	30,717	32,950	35,300	35,300	30,717	32,950	35,300	35,300
14		*Total Operation*	0	699	0	0	43,603	47,507	57,600	57,600	236,392	253,121	360,478	367,446
15														
16	590	Maint Supv & Eng	0	0	0	0	0	0	0	0	85,710	97,875	100,771	101,784
17	591	Maintenance of Structures	1,056	0	0	0	0	0	0	0	1,848	0	0	0
18	592	Maintenance of Station Equipment	0	0	0	0	0	0	0	(110,119)	5,697	3,210	4,571	18,557
19	593	Maintenance of Overhead Lines	39,721	6,362	36,582	38,022	466,984	508,315	537,673	538,577	836,769	869,788	969,072	985,327
20	594	Maintenance of Underground Lines	0	0	0	0	23,250	23,079	33,500	33,500	28,436	30,206	40,056	40,313
21	595	Maintain Line Transformers	2,987	10,115	3,000	3,000	0	0	0	0	5,677	14,532	7,873	8,064
22	596	Maint. Street Light & Signal Expense	0	0	0	0	0	0	0	0	2,991	1,612	907	942
23	597	Maintenance of Misc. Distribution Pla	(529)	8	0	0	2,674	937	0	0	75,467	64,505	78,208	80,194
24		*Total Maintenance*	43,235	16,485	39,582	41,022	492,908	532,331	571,173	461,958	1,042,595	1,081,729	1,201,459	1,235,182
25		*Total Distribution Expenses*	43,235	17,184	39,582	41,022	536,511	579,837	628,773	519,558	1,278,988	1,334,849	1,561,937	1,602,629
26														
27		Customer Accounting & Collection Expenses:												
28	902	Meter Reading Expense	0	0	0	0	0	0	0	0	19,808	21,775	15,922	16,544
29	903	Customer Records & Collection Exp	0	0	0	0	179,184	191,852	220,675	220,675	872,949	907,634	1,015,031	1,047,510
30	904	Uncollectible Accounts	0	0	0	0	0	0	20,000	20,000	0	0	20,000	20,000
31		*Total Customer Accounting & Collecti*	0	0	0	0	179,184	191,852	240,675	240,675	892,757	929,410	1,050,953	1,084,054
32														
33	908	Cust Assist-Energy Audit-Misc	0	0	0	0	295	0	1,000	1,000	2,030	180	1,227	1,237
34	909	Cust Service Info-Misc	0	0	0	0	314	800	16,000	6,000	314	800	16,000	6,000
35	913	Advertising Exp	0	0	0	0	1,738	2,191	2,500	2,500	1,738	2,191	2,500	2,500
36	908-913	Safety and Communications	0	0	0	0	2,347	2,991	19,500	9,500	4,082	3,171	19,727	9,737
37														

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Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026
Expenses By Account
Year 2013, HY 2024, FTY 2025 and FPFTY 2026

Line	Acct.	Account Description	Trans/Mat 12/31/23	Trans/Mat 12/31/24	Trans/Mat 12/31/25	Trans/Mat 12/31/26	Other 12/31/23	Other 12/31/24	Other 12/31/25	Other 12/31/26	Total 12/31/23	Total 12/31/24	Total 12/31/25	Total 12/31/26
38	Administrative & General Expenses:													
39	920	Administrative & General Salaries	0	0	0	0	0	0	0	0	652,639	757,901	869,897	911,229
40	921	Office Supplies & Expenses	0	0	0	0	61,925	112,900	123,007	109,710	61,925	112,900	123,007	109,710
41	923	Outside Services Employed	0	0	0	0	87,889	137,115	154,525	154,525	87,889	137,115	154,525	154,525
42	924	Property Insurance	0	0	0	0	51,268	53,098	61,410	61,410	51,268	53,098	61,410	61,410
43	926	Employee Pensions & Benefits	0	0	0	0	0	0	0	0	0	0	0	0
44	928	Regulatory commission expenses	0	0	0	0	68,366	42,985	43,000	153,393	68,366	42,985	43,000	153,393
45	930	Miscellaneous General Expense	0	0	0	0	102,281	84,404	96,651	107,481	105,355	84,404	99,751	110,581
46	931	Rents	0	0	0	0	2,442	3,611	2,200	2,200	2,442	3,611	2,200	2,200
47	932	Maintenance of general plant	0	0	0	0	62,014	60,822	114,826	114,826	112,580	72,186	132,847	133,551
48		*Total Administrative & General Expen*	0	0	0	0	436,186	494,935	595,619	703,545	1,142,464	1,264,200	1,486,637	1,636,599
49														
50		**Total Operating & Maintenance Ex**	**$43,235**	**$17,184**	**$39,582**	**$41,022**	**$1,154,228**	**$1,269,615**	**$1,484,567**	**$1,473,278**	**$3,318,291**	**$3,531,630**	**$4,119,254**	**$4,333,019**
											3,318,291	3,531,630	4,119,254	4,333,019

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Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026
Workpaper 2 to Schedule C
Accumulated Deferred Income Taxes
Years 2024 through 2026

Line	WECO	2024	2025	2026
1				
2	Book	15,226,786	17,226,319	19,321,064
3				
4	Federal Tax - MACRS	26,171,198	28,090,123	30,042,650
5				
6	Federal Tax - SL	26,630,508	28,182,113	29,858,231
7				
8	PA Tax	20,882,587	23,059,206	25,254,821
9				
10	Federal Tax Depr Exp - MACRS	1,979,408	1,918,925	1,952,528
11				
12	Federal Tax Depr Exp - SL	1,598,164	1,551,605	1,676,119
13				
14	PA Tax Depr Exp	2,466,799	2,176,619	2,195,614
15				
16				
17				
18				
19				
20				

BEFORE

THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	**:**	
	:	
v.	**:**	**Docket No. R-2025-3054392**
	:	
Wellsboro Electric Company	**:**	

REBUTTAL TESTIMONY

AND EXHIBIT

OF

HOWARD S. GORMAN

ON BEHALF OF

WELLSBORO ELECTRIC COMPANY

AUGUST 13, 2025

BEFORE

THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	**Docket No. R-2025-3054392**
	:	
Wellsboro Electric Company	:	

REBUTTAL TESTIMONY OF HOWARD S. GORMAN ON BEHALF OF WELLSBORO ELECTRIC COMPANY

Q. Please state your name, occupation and business address.

A. My name is Howard Gorman. I am the President of HSG Group, Inc., a consulting firm specializing in utility rate and regulatory matters, located in Great Neck, NY.

Q. Are you the same Howard Gorman that provided Direct Testimony on behalf of Wellsboro Electric Company ("Wellsboro" or "Company")?

A. Yes. Terms defined in my Direct Testimony have the same meaning in this Rebuttal Testimony.

Q. What is the purpose of your testimony today?

A. The purposes of my testimony are to update the Company's filing and to rebut portions of the testimony of the following witnesses:

- Bureau of Investigation and Enforcement ("I&E") Witness Walker (I&E St. No. 1), regarding Pennsylvania Corporate Income Tax rate, Rate Case expense, Unamortized Rate Case expense and Cash Working Capital.
- I&E Witness Cline (I&E St. No. 3), regarding Materials and Supplies and Customer Deposits amounts in Rate Base, Scale Back and Customer charges.
- Office of Consumer Advocate ("OCA") Witness Myer (OCA St. No. 1), regarding Revenue at present rates and Uncollectible accounts expense.

- OCA Witness Deupree (OCA St. No. 3), regarding the Company's Allocated Class Cost of Service Study ("ACOS"), Revenue allocation and Rate design.

Q. Are you sponsoring any exhibits today?

A. Yes, I am sponsoring Exhibit___(HSG-1R), which includes an index on Schedule A (R). The Company is supporting an increase of $2,848,804 compared to $2,899,388 in its original filing, reflecting the changes shown in Table HSG-1:

Line	Table HSG-1	Revenue Increase
1	Original Filing	2,899,388
2	Update PA Tax rates	(54,519)
3	Customer counts, 2025 and 2026	33,045
4	Materials & Supplies, Customer Deposits- Most recent 13-months	11,130
5	Remove Duplicate IT Acct 932	(40,240)
6		2,848,804

These changes in the revenue requirement are summarized below:

Items Discussed Below

- PA Corporate Income tax rate - Change to 7.49% in 2026
- Materials and Supplies and Customer Deposits - Include most recent 13-month average balances in rate base
- Cash Working Capital - Adjust the allowance in Rate Base to equal 1/8 times applicable expenses.
- Revenue Allocation and Rate Design - Revenue Allocation and Rate Design are updated for the revenue requirement on Exhibit___(HSG-1R), Schedule C1 (R).

Items Discussed In Rebuttal Testimony of Other Company Witnesses

- Customer Counts - Correct clerical error identified in response to OCA-IX-6.
- Lobbying expense - Remove $32 from Account 930 (Wellsboro St. No. 5-R)

- Information Technology ("IT") - Remove $40,240 in FPFTY and $34,816 in FTY from Account 932 to eliminate double count of certain IT costs (Wellsboro St. No. 5R)

Q. Have you updated the ACOS, revenue allocation and rates that Wellsboro is proposing to recover its revenue requirement?

A. Yes. The results of the ACOS, and the class revenue required to produce a return of 8.172% (target 8.18%; difference is due to rounding in rates), are on Schedule B6-4 (R), lines 1-21. There were no changes in methodology in preparing this ACOS, from the original filed ACOS.

The proposed revenue allocation, presented on Schedule B6-4 (R), lines 24-47 including metrics.

The proposed rates, which produce the revenue target for each class as well as the overall revenue target, are developed on Schedule B6-3 (R), with bill impacts on Schedules B8 (R) I will discuss the scale back methodology later in this testimony.

I&E Witness Walker

PA Corporate Income Tax Rate

Q. What does Mr. Walker propose regarding the PA Corporate Income Tax rate?

A. Mr. Walker notes that pursuant to Pennsylvania House Bill 1342 and Act 53 of 2022, the PA Corporate Income Tax rate is 8.49% in 2024, 7.99% in 2025 and 7.49% in 2026, with annual reductions of 0.5% until it reaches 4.99% in 2031 (I&E St. No. 1, p. 22). Wellsboro's original filing inadvertently used 9.99% for 2026. Wellsboro agrees that the appropriate rate for 2026 is 7.49%. The correct rates as proposed by Mr. Walker are reflected in the Company's Rebuttal filing, Exhibit___(HSG-1R).

Rate Case Expense

Q. What does Mr. Walker propose regarding Rate Case Expense?

A. Mr. Walker proposes normalizing the Company's Rate Case expense over 60 months, which would reduce the annual expense by $44,157 to $66,236 (I&E St. 1, p. 9). His reason is that the average interval between rate cases for the Company's last four rate cases has been 69 months. The Company has proposed normalization over 36 months.

Q. Do you agree with this proposed adjustment?

A. No. As Mr. Farnsworth explains, the Company was able to avoid filing a rate case in 2022, when its sister companies Citizens' Electric Company of Lewisburg, PA ("Citizens'") and Valley Energy, Inc. ("Valley") filed rate cases, due to exceptional and abnormal load growth at that time. Wellsboro's projections for the upcoming period do not include similar abnormal load growth. Additionally, as explained by Mr. Farnsworth in his Rebuttal Testimony, the Company was able to manage operating expenses and supplement revenues by participating in temporary funding programs made available during the COVID-19 pandemic. Those funding sources were unique and non-recurring.

Based on the non-recurring nature of the factors that allowed the Company to avoid a 2022 rate case filing, the Company expects it will need to file approximately every three years, to account for expected declines in annual usage per customer as discussed below, continuing cost escalation, and the need to continue to invest in plant. Notably, Wellsboro's sister company, Citizens', proposed a three-year normalization period, and no intervenor has objected to this. The Company's proposed three-year normalization period is customary and reasonable, and this adjustment should be rejected by the Commission.

Unamortized Rate Case Expense

Q. What does Mr. Walker propose regarding Unamortized Rate Case Expense?

A. Mr. Walker proposes removing Unamortized Rate Case expense from rate base, on the grounds that Rate Case expense is a normal operating expense for a utility, and the utility should not earn a return on a normal operating expense (I&E St. No. 1, pp. 14-15).

Q. Do you agree?

A. No. The utility has working capital tied up in unrecovered Rate Case expense and is entitled to a return on that working capital. The Company pays the Rate Case expense on a real-time basis during the proceeding, then collects the projected amount included in the Rate Case expense claim over the normalization period without carrying charges. As such, allowing the return on the balance is necessary to compensate Wellsboro for the delay between paying the expense and receiving the compensation in post-proceeding distribution revenues.

This treatment is analogous to Materials and Supplies, where the Company has laid out or committed working capital and the item has not flowed through expense yet. The cost of unused Materials and Supplies is routinely included in rate base. For the same reason, the unrecovered portion of Rate Case expense should be included as well, and this adjustment should be rejected.

Cash Working Capital

Q. What does Mr. Walker propose regarding Cash Working Capital?

A. Mr. Walker proposes that the Cash Working Capital ("CWC") allowance be computed based on the Commission's determination of revenue, expenses, taxes and rate base in this case (I&E St. No. 1, pp. 20-21). He accepts the Company's use of the 1/8 convention in

computing CWC. The Company has adjusted its CWC claim in Rebuttal using the 1/8 convention and will use this approach for the final revenue requirement. The Company accepts this proposal.

I&E Witness Cline

Materials and Supplies and Customer Deposits

Q. What does Mr. Cline propose regarding Materials and Supplies and Customer Deposits?

A. Mr. Cline proposes including these two items in Rate Base based on their 13-month averages for the most recent periods available at the time of determination. (I&E St. No. 3, pp. 6-8). The Company accepts this proposal and has reflected it in its Rebuttal filing, Exhibit___(HSG-1R), Schedule C1-5 (R).

Scale Back and Customer Charges

Q. What does Mr. Cline propose regarding Scale Back and Customer Charges?

A. Mr. Cline accepts the customer charges proposed by the Company based on the revenue requirement in its original filing. He proposes that the final rates be based on "the cost of service study ultimately approved by the Commission." (I&E St. 3, pp. 10).

If the Commission accepts the Company's ACOS but reduces its requested revenue requirement, then the Company proposes to use a proportionate scale back to allocate the increase. Wellsboro does not agree, however, that the proposed customer charges should be reduced (unless an updated customer cost analysis indicates otherwise). The proposed customer charges are consistent with the Commission's policy and should be approved as submitted. I will address in more detail below why appropriate rate design should include

customer charges at levels that promote revenue stability for the utility and balance other factors.

OCA Witness Meyer

Revenue

Q. What adjustments to Revenue does Mr. Meyer propose?

A. The Company's sales and revenue forecast was based on annual average kWh per customer, by rate class, over the most recent 5 years. Mr. Meyer proposes using the most recent 10 years, which he supports by showing that the 10-year average is close to the 15-year average. (OCA St. No. 1, pp. 5-9).

Q. Does Mr. Meyer's analysis support his proposed adjustment?

A. No, I believe his analysis supports the Company's position.

First, the sales forecast represents normalized annual use per customer multiplied by expected number of customers. Normalized annual use per customer data was developed by Wellsboro in a special study. This information has been provided to Mr. Meyer in the Company's response to OCA-IX-6. Mr. Meyer did not identify any errors in the special study or even discuss it in his testimony.

Second, and of paramount importance, as shown in Table HSG-2 below, these classes have shown marked declines in annual kWh usage per customer in recent periods. In fact, the 2023 and 2024 numbers are well below the 5-year averages. In his Rebuttal Testimony (Wellsboro Statement No. 4R), Mr. Farnsworth explains the reasons for the decreasing average customer sales. Mr. Meyer's adjustment would exacerbate under-collection of revenues, would shortchange the company in the short run, and would accelerate the need for the next rate case. This adjustment should be rejected by the Commission.

Line	Table HSG-2	Sch. 3- NRS	Sch. 4- CS	NRS+CS		Sch. 5- IS
1	Average Annual kWh Per Customer					
2	15-year Average			26,369		2,608,906
3	10-year Average			25,920		2,364,313
4	5-year Average (be	4,734	72,220	24,645		2,124,133
5						
6	Change 15-year to 10-year			(1.70%)		(9.38%)
7	Change 10-year to 5-year			(4.92%)		(10.16%)
8	Change 5-year to 2(	(7.03%)	(4.36%)	(4.55%)		(10.88%)
9						
10	Annual 2020	4,891	71,936	24,839		2,277,800
11	Annual 2021	4,957	73,680	25,171		2,301,290
12	Annual 2022	4,783	75,368	25,476		2,110,702
13	Annual 2023	4,640	71,040	24,214		2,037,783
14	Annual 2024	4,402	69,074	23,524		1,893,091

OCA Witness Deupree

ACOS

Q. Please summarize Mr. Deupree's views regarding the Company's ACOS.

A. Mr. Deupree appears to accept the Company's ACOS, *except for* the classification of Secondary portions of distribution plant (accounts 364, 365, 366) and Line Transformers (account 368). He claims these items have no customer component and are 100% demand-related. He makes the following arguments in support of his claims:

- Theoretical Nature of Zero-Load System - Mr. Deupree notes that the Company's separation of costs into demand-related and customer-related is based on "hypotheticals that do not exist in the real world, including the assumption that somehow there is an electric distribution system out there in the world that could or would be plausibly built to serve customers but not load." (OCA St. No. 3, p. 17).

  This is an often used, but misleading argument. I acknowledge that the Zero-Load System and the Minimum Size System are theoretical constructs, but this is not a valid reason to reject them. They are useful tools to separate costs between demand-related and customer-related, regardless of the fact that no such systems would be built.

As an aside, Mr. Deupree's argument regarding Line Transformers is incorrect and falls apart. It would be possible to install transformers with ratings of 10 kVA for customers where this is sufficient to meet demand and to install larger capacity transformers where needed.

- Load Carrying Capacity - Mr. Deupree cites the National Association of Regulatory Utility Commissioners ("NARUC") Manual's caution that a minimum system would have a certain load-carrying capacity. (OCA St. 3, pp. 17-18).

  For items other than Line Transformers, the Zero-Load System presented in my ACOS excludes the cost of materials and would have no load-carrying capacity.

  For Line Transformers, the demand component does reflect the capacity of the minimum system. (Exhibit___(HSG-1R), Schedule D2 (R), lines 18-22, with the capacity of the minimum system shown on line 20).

- Bonbright - Mr. Deupree cites Professor Bonbright's claim that including the minimum-sized distribution system in customer-related costs is "clearly indefensible." (Bonbright, p. 492, cited at OCA St. No. 3, p. 20). Yet, he ignores Bonbright's claim that "its exclusion from the demand-related costs stands on much firmer ground" (Bonbright, p. 492) and goes ahead and classifies all costs, including any minimum size component, as demand-related. One cannot simultaneously criticize and rely on the same source.

- Relation to Number of Customers - Mr. Deupree analyzes the relationship between the number of customers the Company added (or lost) 2008 through 2024, and net dollar additions to distribution plant. Unsurprisingly, he finds no statistical correlation (OCA St. No. 3, p. 20).

I applaud Mr. Deupree's efforts, but I disagree with his conclusion that because he could not demonstrate statistical correlation, there is no relationship between the number of customers added and distribution system costs. On the face of it, this conclusion does not make sense. Even in years with decreases in the number of customers, the utility must invest in the distribution system. The reasons that Mr. Deupree does not demonstrate correlation include: the amount of net investment is affected by asset retirements; net dollar additions to distribution plant vary due to factors other than new customers, such as repairs, maintenance and upgrades; the timing of customer additions has not been matched to the timing of investments; and critically, the dollar value of investments may be affected by demand capacity added, which the analysis ignores.

Mr. Deupree's conclusion that because he could not demonstrate statistical correlation, there is therefore no relationship between the number of customers added and distribution system costs, is wrong.

Q. Please summarize the discussion regarding Mr. Deupree's objections to your ACOS.

A. First, the endpoints of the distribution system connect to customers, usually through a transformer; it is a tautology that the investment in distribution system, especially the Secondary system, is directly related to the number of customers. Regarding Transformers, the Company uses the rule of thumb that one 10kVA transformer serves one customer (Schedule D3), establishing a direct relationship between this particular component and the number of customers.

Second, each of the several arguments that Mr. Deupree raised are flawed, as discussed above.

Q. Do other intervenors comment on the Company's ACOS?

A. Yes. Office of Small Business Advocate ("OSBA") Witness Farr concludes that "the cost of service study aligns with the principles of cost causation and that [the Company's] proposed revenue allocation falls within the range of reasonableness." (OSBA St. No. 1, p. 3). I&E Witness Cline does not comment on the ACOS but relies on the Company's ACOS to review customer charges. (I&E. St. No. 3, p. 8).

Q. Has the Commission provided guidance regarding minimum system studies in allocated cost studies?

A. Yes, many times. The Commission repeatedly has endorsed minimum system studies, including in Wellsboro's 2019 rate case, in Citizens' 2019 rate case at Docket No. R-2019-3008212, in UGI Utilities, Inc.—Electric Division's 2018 rate case at Docket No. R-2017-2640058, and in PPL Electric Utilities Corporation's 2019 and 2012 rate cases. The Commission found that Wellsboro's analysis in the 2019 rate case, which I personally performed, was reasonable and appropriate for the classification and allocation of distribution system costs.

Q. What do you recommend regarding the Company's ACOS?

A. The Commission must reject Mr. Deupree's criticism of the Company's ACOS for the reasons stated above. The Commission should accept the Company's ACOS, found in Exhibit___(HSG-1R), Schedule E (R). This ACOS is based on the Company's revenue requirement submitted in Rebuttal, and uses the same methodology as the Company's originally filed ACOS as set forth in Exhibit___(HSG-1), Schedule E.

Revenue Allocation

Q. What does Mr. Deupree recommend regarding revenue allocation?

A. Mr. Deupree prepared his own ACOS, in which he failed to recognize any customer component of the Secondary distribution system. This is a fatal flaw. He relies on his ACOS for revenue allocation. Because Mr. Deupree's ACOS is fatally flawed, the Commission should reject it and should also reject his recommendations as to revenue allocation, as they rely on the flawed ACOS.

Rate Design

Q. What does Mr. Deupree recommend regarding rate design?

A. Mr. Deupree recommends that the Commission reject the Company's proposed increases to Customer charges. He cites several reasons, which I address below.

- Computation of customer-related costs - Mr. Deupree claims the Company's ACOS inaccurately reflects customer-related costs and, presumably, should not be relied on to develop the Customer charge. However, the Company's analysis of customer-related costs for inclusion in the Customer charge (Exhibit__(HSG-1R), Schedule E-1C(R)) excludes the Secondary portion of the distribution system, which is the only portion of the ACOS that Mr. Deupree contested. The analysis does include Transformers; however, the impact of Transformers on the costs is minor in comparison to the total costs that are included in the analysis. Mr. Deupree has not identified a significant flaw in my computation of the customer-related costs.
- Comparison to other regional utilities - Mr. Deupree claims the Company's present and proposed Customer charges for residential and small commercial customers are higher than the charges of neighboring utilities. This is not relevant to our discussion—the

relevant issue is how the current and proposed charges compare to the results of the computation of customer-related costs.

- Effect on energy conservation and low-usage customers - Mr. Deupree claims that higher Customer charges are contrary to the goal of energy conservation. However, the goal of energy conservation should not be considered in a vacuum; rate design must balance this with concerns such as revenue stability for the utility and efficient price signals, as well as affordability. In fact, Commission policy permits only certain costs to be recovered in the customer charge, and these do not include all fixed costs the utility incurs. As proposed, the customer charge recovers only 28.7% of monthly distribution charges for a typical residential customer using 750 kWh per month, while the remaining 71.3% is recovered on a kWh basis. This does not include the impact of the Generation Supply Service Rate ("GSSR"), which is recovered fully on a kWh basis. Inefficient pricing and under-recovery of costs lead to more frequent rate cases and also to cross-subsidies within rate classes, as costs are shifted to higher-usage customers.

OSBA Witness Farr

PA Corporate Income Tax Rate

Q. What does Mr. Farr propose?

A. Mr. Farr makes the same proposal as Mr. Walker regarding the PA Corporate Income Tax rate (OSBA St. No. 1, pp. 7-8); as discussed above, the correct rates are reflected in the Company's Rebuttal filing, Exhibit___(HSG-1R).

Q. Does this conclude your Rebuttal Testimony today?

A. Yes.

BEFORE

THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	**:**	
	:	
v.	**:**	**Docket No. R-2025-3054392**
	:	
Wellsboro Electric Company	**:**	

EXHIBIT

OF

HOWARD S. GORMAN

ON BEHALF OF

WELLSBORO ELECTRIC COMPANY

AUGUST 13, 2025

A (R)

Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026 (R)
INDEX TO SCHEDULES

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A (R)

Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026 (R)
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B (R)

Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026 (R)

Operating Revenues Under Present Rates
12/31/2024, 12/31/2025 and 12/31/2026

Answer to 52 Pa. Code 53.52 b[2]

Line	Customer Type	HY 2024 Total Revenue- Present Rates	HY 2024 Distribution Only	Present Rates FTY 2025 Distribution Only	Present Rates FPFTY 2026 Distribution Only
		B1 (R)		B2-1 (R)	B3-1 (R)
1	Residential	$6,829,521	$3,190,200	$3,382,268	$3,382,057
2	Commercial and Industrial	5,657,570	2,642,167	2,876,554	2,883,240
3	Lighting	100,851	95,243	94,867	94,867
4	Sales for resale	17,863	8,957	8,957	8,957
5		12,605,805	5,936,568	6,362,646	6,369,121
6					
7	Forfeited Discounts	28,860	28,860	30,931	30,962
8	Rent from Electric Property	266,738	266,738	266,738	273,619
9	Other electric revenue	22,899	22,899	22,899	22,899
10	Sales Tax, STAS				
11	Unbilled	234,090			
12	Adjustments				
13	**Total Operating Revenues**	$13,158,392	$6,255,065	$6,683,214	$6,696,602
14	*Financials*	*$13,158,392*			
15	kWh				
16	Residential	41,774,098	41,774,098	45,036,833	45,033,424
17	Commercial and Industrial	54,875,548	54,875,548	58,572,601	60,029,081
18	Lighting	267,068	267,068	267,068	0
19	Sales for resale	102,572	102,572	102,572	102,572
20		97,019,287	97,019,287	103,979,075	105,165,077
21					

Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026 (R)

Summary Of Electric Sales, Customers And Revenue At Present Rates
Historic Year 2024

Line	Rate Class	Sales (kWh)	Average Customers	Revenue - Present Rates: Fixed Customer Charge	Variable Distribution-Energy	Variable Distribution-Demand	Distribution Total	GSSR	STAS	Total Revenue
1										
2	Residential Customers									
3	Schedule 1- RS	41,448,363	5,130	$738,672	$2,430,532	$0	$3,169,204	$3,611,216	($697)	$6,779,723
4	Schedule 2- RSAE	325,735	30	4,296	16,700	0	20,996	28,807	(5)	49,799
5		41,774,098	5,160	742,968	2,447,232	0	3,190,200	3,640,023	(702)	6,829,521
6										
7	Commercial and Industrial Customers									
8	Schedule 3- NRS	3,958,829	908	133,112	302,059	0	435,171	335,804	(72)	770,904
9	Schedule 3- NRH	10,826	1	183	917	0	1,100	954	(0)	2,054
10	Schedule 4- CS	26,289,234	381	146,473	596,240	661,390	1,404,103	1,700,741	(319)	3,104,525
11	Schedule 4- CSH	6,480	1	550	429	0	979	557	(0)	1,536
12	Schedule 5- IS	24,610,180	13	13,260	184,668	602,886	800,814	977,913	(175)	1,778,551
13		54,875,548	1,304	293,579	1,084,313	1,264,276	2,642,167	3,015,968	(565)	5,657,570
14										
15	Schedule 6- Municipal Street Lights	64,798	Not shown	0	13,576	0	13,576	5,609		19,185
16	Schedule 7- Private Outdoor Lights	202,270	Not shown	0	81,667	0	81,667	0	(2)	81,665
17	Lighting	267,068	0	0	95,243	0	95,243	5,609	(2)	100,851
18										
19	Schedule 8- Exchange Utility	102,572	4	0	8,957	0	8,957	8,907		17,863
20										
21	TOTAL	97,019,287	6,468	$1,036,547	$3,635,745	$1,264,276	$5,936,568	$6,670,507	($1,270)	$12,605,805

B1-1 (R)

Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026 (R)
Billing Units, Rates And Revenue At Present Rates
Historic Year 2024

Line		Sch. 1- RS	Sch. 2- RSAE	Sch. 3- NRS	Sch. 3- NRH	Sch. 4- CS	Sch. 4- CSH	Sch. 5- IS	Sch. 6- MSL	Sch. 7- POL	Sch. 8- EU	Total
1						**BILLING UNITS**						
2	kWh Sales	41,448,363	325,735	3,958,829	10,826	26,289,234	6,480	24,610,180	64,798	202,270	102,572	97,019,287
3												
4	Number of Bills	61,556	358	10,893	15	4,573	12	156			48	77,611
5	Average Monthly Bills	5,130	30	908	1	381	1	13			4	6,468
6												
7						**Annual Billing Units- Public Lighting and Street Lighting HY 2024**						
8	MV 20000 lumens								12	12		24
9	LED 50 OH								1,776	5,104		6,880
10	LED 50 UG								0	0		0
11	LED 50 UG Col								0	0		0
12	LED 70 OH								1,307	4,365		5,672
13	LED 70 UG								0	0		0
14	LED 140 OH								0	24		24
15	LED 140 UG								0	0		0
16									3,095	9,505		12,600
17						**RATES AND CHARGES**						
18						**Tariff Rates**						
19	Customer Charge	$12.00	$12.00	$12.22	$12.22	$32.03	$45.81	$85.00				
20												
21	Energy Block 1	$0.058640	$0.051270	$0.076300	$0.084690	$0.022680	$0.066280	$0.020780	$10.76	$8.81	$0.08732	
22	Energy Block 2							$0.001300	$4.12	$8.33		
23									$11.06	$11.06		
24									$16.03	$16.03		
25									$4.69	$8.89		
26									$11.62	$11.62		
27									$5.81	$10.02		
28									$12.75	$12.75		
29												
30	Block 1 kWh = Demand X							130				
31	Demand Block 1					$6.60		$10.00				
32												
33						**COMPUTATION OF REVENUE**						
34	Customer Charge Revenue	738,672	4,296	133,112	183	146,473	550	13,260	0	0	0	1,036,547
35												
36	Distribution kWh Revenue	2,430,532	16,700	302,059	917	596,240	429	184,668	13,576	81,667	8,957	3,635,745
37	Distribution Demand Revenu	0	0	0	0	661,390	0	602,886	0	0	0	1,264,276
38	*Total Distribution Revenue*	2,430,532	16,700	302,059	917	1,257,630	429	787,554	13,576	81,667	8,957	4,900,021

B1-1 (R)

Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026 (R)
Billing Units, Rates And Revenue At Present Rates
Historic Year 2024

Line		Sch. 1- RS	Sch. 2- RSAE	Sch. 3- NRS	Sch. 3- NRH	Sch. 4- CS	Sch. 4- CSH	Sch. 5- IS	Sch. 6- MSL	Sch. 7- POL	Sch. 8- EU	Total
39	**Distribution Revenue**	$3,169,204	$20,996	$435,171	$1,100	$1,404,103	$979	$800,814	$13,576	$81,667	$8,957	$5,936,568
40	**STAS Revenue**	(697)	(5)	(72)	(0)	(319)	(0)	(175)	(2)			(1,270)
41	**Generation Revenue**	3,611,216	28,807	335,804	954	1,700,741	557	977,913	5,609	0	8,907	6,670,507
42	**Total Revenue**	6,779,723	49,799	770,904	2,054	3,104,525	1,536	1,778,551	19,183	81,667	17,863	12,605,805
43												
44		**BILLING UNITS- DETAIL**										
45	Block 1 kWh Sales	41,448,363	325,735	3,958,829	10,826	26,289,234	6,480	7,837,515	64,798	202,270	102,572	80,246,622
46	Block 2 kWh Sales							16,772,665				16,772,665
47	Block 1 kW Demand Computed					100,211		59,872				
48	Block 1 kW Demand Adjustment							417				
49	Block 1 kW Demand					100,211		60,289				160,499

Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026 (R)

Summary Of Electric Sales, Customers And Revenue At Present Rates
Future Test Year 2025

Line	Rate Class	Sales (kWh)	Average Customers	Revenue - Present Rates			
				Fixed Customer Charge	Variable Distribution-Energy	Variable Distribution-Demand	Distribution Total
1							
2	Residential Customers						
3	Schedule 1- RS	44,639,052	5,139	$740,040	$2,617,634	$0	$3,357,674
4	Schedule 2- RSAE	397,781	29	4,200	20,394	0	24,594
5		45,036,833	5,168	744,240	2,638,028	0	3,382,268
6							
7	Commercial and Industrial Customers						
8	Schedule 3- NRS	4,636,750	919	134,799	353,784	0	488,583
9	Schedule 3- NRH	6,256	1	147	530	0	676
10	Schedule 4- CS	28,537,845	385	147,979	647,238	712,800	1,508,017
11	Schedule 4- CSH	7,216	1	550	478	0	1,028
12	Schedule 5- IS	25,384,534	13	13,600	201,050	663,600	878,250
13		58,572,601	1,320	297,074	1,203,080	1,376,400	2,876,554
14							
15	Schedule 6- Municipal Street Lights	64,798	Not shown	0	13,496	0	13,496
16	Schedule 7- Private Outdoor Lights	202,270	Not shown	0	81,371	0	81,371
17	Lighting	267,068	0	0	94,867	0	94,867
18							
19	Schedule 8- Exchange Utility	102,572	4	0	8,957	0	8,957
20							
21	TOTAL	103,979,075	6,492	$1,041,314	$3,944,932	$1,376,400	$6,362,646

B2-1 (R)

Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026 (R)
Billing Units, Rates And Revenue At Present Rates
Future Test Year 2025

Line		Sch. 1- RS	Sch. 2- RSAE	Sch. 3- NRS	Sch. 3- NRH	Sch. 4- CS	Sch. 4- CSH	Sch. 5- IS	Sch. 6- MSL	Sch. 7- POL	Sch. 8- EU	Total
1		**BILLING UNITS**										
2	kWh Sales	44,639,052	397,781	4,636,750	6,256	28,537,845	7,216	25,384,534	64,798	202,270	102,572	103,979,075
3												
4	Number of Bills	61,670	350	11,031	12	4,620	12	160			48	77,903
5	Average Monthly Bills	5,139	29	919	1	385	1	13			4	6,492
6												
7		**Annual Billing Units- Public Lighting and Street Lighting, Future Test Year 2025**										
8	MV 20000 lumens											
9	LED 50 OH								1,788	5,064		6,852
10	LED 50 UG											
11	LED 50 UG Col											
12	LED 70 OH								1,307	4,381		5,688
13	LED 70 UG											
14	LED 140 OH									24		24
15	LED 140 UG											
16									3,095	9,469		12,564
17		**RATES AND CHARGES**										
18		**Tariff Rates**										
19	Customer Charge	$12.00	$12.00	$12.22	$12.22	$32.03	$45.81	$85.00				
20												
21	Energy Block 1	$0.05864	$0.05127	$0.07630	$0.08469	$0.02268	$0.06628	$0.02078	$10.76	$8.81	$0.08732	
22	Energy Block 2							$0.00130	$4.12	$8.33		
23									$11.06	$11.06		
24									$16.03	$16.03		
25									$4.69	$8.89		
26									$11.62	$11.62		
27									$5.81	$10.02		
28									$12.75	$12.75		
29												
30	Block 1 kWh = Demand X							130				
31	Demand Block 1					$6.60		$10.00				
32												

B2-1 (R)

Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026 (R)
Billing Units, Rates And Revenue At Present Rates
Future Test Year 2025

Line		Sch. 1- RS	Sch. 2- RSAE	Sch. 3- NRS	Sch. 3- NRH	Sch. 4- CS	Sch. 4- CSH	Sch. 5- IS	Sch. 6- MSL	Sch. 7- POL	Sch. 8- EU	Total
33						**COMPUTATION OF REVENUE**						
34	Customer Charge Revenue	740,040	4,200	134,799	147	147,979	550	13,600	0	0	0	1,041,314
35												
36	Distribution kWh Revenue	2,617,634	20,394	353,784	530	647,238	478	201,050	13,496	81,371	8,957	3,944,932
37	Distribution Demand Revenue					712,800		663,600				1,376,400
38	*Volumetric Distribution Reve*	2,617,634	20,394	353,784	530	1,360,038	478	864,650	13,496	81,371	8,957	5,321,332
39	**Total Distribution Revenue**	$3,357,674	$24,594	$488,583	$676	$1,508,017	$1,028	$878,250	$13,496	$81,371	$8,957	$6,362,646
40		*3,357,674*	*24,594*	*487,955*		*1,505,471*		*878,250*				
41						**KWh BILLING UNITS- DETAIL**						
42	Average Customers 2024				1	384	1	13	0		4	
43	Customers added (lost)					4						
44	Forecast Customers 2025	5,139	29	919	1	385	1	13	0	0	4	6,492
45	Block 1 kWh Sales	44,639,052	397,781	4,636,750	6,256	28,537,845	7,216	8,626,800	64,798	202,270	102,572	87,221,341
46	Block 2 kWh Sales							16,757,734				16,757,734
47												
48	Source:	Prior Study	Prior Study	Prior Study	Historic	Prior Study	Historic	Prior Study	Historic	Historic	Historic	
49	Forecast kWh 2025 at 2024 Cus	44,639,052	397,781	4,631,285	6,256	28,463,721	7,216	25,384,534	64,798	202,270	102,572	103,899,486
50	Customers Average 2024	5,139	29	918	1	384	1	13			4	6,490
51	Annual Use Per Customer	8,686	13,638	5,044	6,256	74,124	7,216	1,903,840			25,643	
52												
53	Block 1 kW Demand- Same as 2024					108,000		66,360				174,360

Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026 (R)

Summary Of Electric Sales, Customers And Revenue At Present Rates
Fully Projected Future Test Year 2026

Line	Rate Class	Sales (kWh)	Average Customers	Revenue - Present Rates			
				Fixed Customer Charge	Variable Distribution-Energy	Variable Distribution-Demand	Distribution Total
1							
2	Residential Customers						
3	Schedule 1- RS	44,639,052	5,139	$740,040	$2,617,634	$0	$3,357,674
4	Schedule 2- RSAE	394,372	29	4,164	20,219	0	24,383
5		45,033,424	5,168	744,204	2,637,853	0	3,382,057
6							
7	Commercial and Industrial Customers						
8	Schedule 3- NRS	4,657,346	923	135,398	355,356	0	490,753
9	Schedule 3- NRH	6,256	1	147	530	0	676
10	Schedule 4- CS	28,611,970	386	148,363	648,919	712,800	1,510,082
11	Schedule 4- CSH	7,216	1	550	478	0	1,028
12	Schedule 5- IS	26,746,293	14	14,280	202,820	663,600	880,700
13		60,029,081	1,325	298,737	1,208,103	1,376,400	2,883,240
14							
15	Schedule 6- Municipal Street Lights	0	Not shown	0	13,496	0	13,496
16	Schedule 7- Private Outdoor Lights	0	Not shown	0	81,371	0	81,371
17	Lighting	0	0	0	94,867	0	94,867
18							
19	Schedule 8- Exchange Utility	102,572	4	0	8,957	0	8,957
20							
21	TOTAL	105,165,077	6,497	$1,042,941	$3,949,780	$1,376,400	$6,369,121

B3-1 (R)

Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026 (R)
Billing Units, Rates And Revenue At Present Rates
Fully Projected Future Test Year 2026

Line		Sch. 1- RS	Sch. 2- RSAE	Sch. 3- NRS	Sch. 3- NRH	Sch. 4- CS	Sch. 4- CSH	Sch. 5- IS	Sch. 6- MSL	Sch. 7- POL	Sch. 8- EU	Total
1		**BILLING UNITS**										
2	kWh Sales	44,639,052	394,372	4,657,346	6,256	28,611,970	7,216	26,746,293	0	0	102,572	105,165,077
3												
4	Number of Bills	61,670	347	11,080	12	4,632	12	168			48	77,969
5	Average Monthly Bills	5,139	29	923	1	386	1	14			4	6,497
6												
7		**Annual Billing Units- Public Lighting and Street Lighting, Fully Projected Future Test Year 2026**										
8	MV 20000 lumens											
9	LED 50 OH								1,788	5,064		6,852
10	LED 50 UG											
11	LED 50 UG Col											
12	LED 70 OH								1,307	4,381		5,688
13	LED 70 UG											
14	LED 140 OH									24		24
15	LED 140 UG											
16									3,095	9,469		12,564
17		**RATES AND CHARGES**										
18		**Tariff Rates**										
19	Customer Charge	$12.00	$12.00	$12.22	$12.22	$32.03	$45.81	$85.00				
20												
21	Energy Block 1	$0.05864	$0.05127	$0.07630	$0.08469	$0.02268	$0.06628	$0.02078	$10.76	$8.81	$0.08732	
22	Energy Block 2							$0.00130	$4.12	$8.33		
23									$11.06	$11.06		
24									$16.03	$16.03		
25									$4.69	$8.89		
26									$11.62	$11.62		
27									$5.81	$10.02		
28									$12.75	$12.75		
29												
30	Block 1 kWh = Demand X							130				
31	Demand Block 1					$6.60		$10.00				
32												
33		**COMPUTATION OF REVENUE**										
34	Customer Charge Revenue	740,040	4,164	135,398	147	148,363	550	14,280	0	0	0	1,042,941
35												
36	Distribution kWh Revenue	2,617,634	20,219	355,356	530	648,919	478	202,820	13,496	81,371	8,957	3,949,780
37	Distribution Demand Revenue					712,800		663,600				1,376,400

B3-1 (R)

Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026 (R)
Billing Units, Rates And Revenue At Present Rates
Fully Projected Future Test Year 2026

Line		Sch. 1- RS	Sch. 2- RSAE	Sch. 3- NRS	Sch. 3- NRH	Sch. 4- CS	Sch. 4- CSH	Sch. 5- IS	Sch. 6- MSL	Sch. 7- POL	Sch. 8- EU	Total
38	*Volumetric Distribution Rever*	2,617,634	20,219	355,356	530	1,361,719	478	866,420	13,496	81,371	8,957	5,326,180
39	**Total Distribution Revenue**	$3,357,674	$24,383	$490,753	$676	$1,510,082	$1,028	$880,700	$13,496	$81,371	$8,957	$6,369,121
40		*3,357,674*	*24,303*	*490,190*		*1,507,533*		*880,700*				
41		**BILLING UNITS- DETAIL**										
42	Forecast Customers 2025				1		1	13			4	
43	Customers added (lost)											
44	Forecast Customers 2026	5,139	29	923	1	386	1	14	0	0	4	6,497
45	Block 1 kWh Sales	44,639,052	394,372	4,657,346	6,256	28,611,970	7,216	8,626,800	0	0	102,572	87,045,584
46	Block 2 kWh Sales							18,119,493				18,119,493
47								26,746,293				
48												
49												
50	From Sch B2-1											
51	Annual Use Per Customer	8,686	13,638	5,044	6,256	74,124	7,216	1,903,840			25,643	
52												
53	Block 1 kW Demand- Same as 2024					108,000		66,360				174,360
54												

B4 (R)

Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026 (R)

Bill Analysis- Revenues Under Present Rates
Historic Year 2024

B1

Line	Customer Type	Bill Analysis Revenue	GSSR	STAS	Distribution plus GSSR	Unbilled and GSSR Over/ (Under)	Other	Revenue Computed	Revenue per 2024 Financial Statements
1	Residential	$3,190,200	$3,640,023	($702)	$6,829,521	$157,897		$6,987,418	$6,987,418
2	Commercial and Industrial	2,642,167	3,015,968	(565)	5,657,570	157,635		5,815,205	5,815,205
3	Lighting	95,243	5,609	(2)	100,851	(81,649)		19,202	19,202
4	Exchange Utility	8,957	8,907	0	17,863	207		18,070	18,070
5		5,936,568	6,670,507	(1,270)	12,605,805	234,090	0	12,839,895	12,839,895
6									
7	Forfeited Discounts						28,860	28,860	28,860
8	Rent from Electric Property						266,738	266,738	266,738
9	Other electric revenue						22,899	22,899	22,899
10									
11		$5,936,568	$6,670,507	($1,270)	$12,605,805	$234,090	$318,497	$13,158,392	$13,158,392
12									

B5 (R)

Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026 (R)

Number of Customers Served Whose Bills Will be Increased
12/31/2024, 12/31/2025 and 12/31/2026
Answer to 52 Pa. Code 53.52 b[3]

Line	Customer Type	Total Customers 12/31/2024	Total Customers 12/31/2025	Total Customers 12/31/2026
1	Residential	5,160	5,168	5,168
2	Commercial and Industrial	1,304	1,320	1,325
3	Lighting	0	0	0
4	Exchange Utility	4	4	4
5	Total Customers Served	6,468	6,492	6,497
6				
7				
8				

B6 (R)

Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026 (R)

Operating Revenue Under Present Rates and Proposed Rates
12/31/2024, 12/31/2025 and 12/31/2026
Answer to 52 Pa. Code 53.52 b[4]

Line	Description	Total	Distribution Only			
		HY 2024 Total Revenue	HY 2024	FTY 2025 PRESENT Rates	FPFTY 2026 PRESENT Rates	FPFTY 2026 PROPOSED Rates
1	**Operating Revenues**	B (R)	B (R)	B (R)	B (R)	B6-1 (R)
2	Residential	$6,829,521	$3,190,200	$3,382,268	$3,382,057	$5,037,014
3	Commercial and Industrial	5,657,570	2,642,167	2,876,554	2,883,240	4,055,722
4	Lighting	100,851	95,243	94,867	94,867	113,392
5	Exchange Utility	17,863	8,957	8,957	8,957	12,118
6	Subtotal	12,605,805	5,936,568	6,362,646	6,369,121	9,218,245
7						
8	Forfeited Discounts	28,860	28,860	30,931	30,962	30,962
9	Rent from Electric Property	266,738	266,738	266,738	273,619	273,619
10	Other electric revenue	22,899	22,899	22,899	22,899	22,899
11	Annual Rates vs Present Rates					
12	Book to Bill difference	234,090				
13	Adjustments	0				
14	Total Operating Revenues	$13,158,392	$6,255,065	$6,683,214	$6,696,602	$9,545,726
15						
16	kWh					
17	Residential	41,774,098		45,036,833	45,033,424	
18	Commercial and Industrial	54,875,548		58,572,601	60,029,081	
19	Lighting	267,068		267,068	0	
20	Sales for resale	102,572		102,572	102,572	
21		97,019,287		103,979,075	105,165,077	

Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026 (R)

Summary Of Proposed Increase to Distribution Revenue
Fully Projected Future Test Year 2026

Line	Rate Class	Sales (kWh)	Average Customers	Distribution Total Present Rates	Distribution - Proposed Increase	Distribution Total Proposed Rates
1	Residential Customers	B3	B3	B3		B6-2
2	Schedule 1- RS	44,639,052	5,139	3,357,674	1,640,345	4,998,019
3	Schedule 2- RSAE	394,372	29	24,383	14,611	38,995
4	Schedule RS- Residential Service	45,033,424	5,168	3,382,057	1,654,957	5,037,014
5						
6	Commercial and Industrial Customers					
7	Schedule 3- NRS	4,657,346	923	490,753	229,711	720,464
8	Schedule 3- NRH	6,256	1	676	507	1,184
9	Schedule 4- CS	28,611,970	386	1,510,082	591,268	2,101,351
10	Schedule 4- CSH	7,216	1	1,028	771	1,799
11	Schedule 5- IS	26,746,293	14	880,700	350,224	1,230,925
12		60,029,081	1,325	2,883,240	1,172,482	4,055,722
13						
14	Schedule 6- Municipal Street Lights	0	Not shown	13,496	6,004	19,500
15	Schedule 7- Private Outdoor Lights	0	Not shown	81,371	12,521	93,892
16	Lighting	0	0	94,867	18,525	113,392
17						
18	Schedule 8- Exchange Utility	102,572	4	8,957	3,161	12,118
19						
20	TOTAL	105,165,077	6,497	$6,369,121	$2,849,124	$9,218,245

Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026 (R)

Summary Of Electric Sales, Customers And Revenue At Proposed Rates
Fully Projected Future Test Year 2026

Line	Rate Class	Sales (kWh)	Average Customers	Revenue - Proposed Rates			
				Fixed Customer Charge	Variable Distribution-Energy	Variable Distribution-Demand	Distribution Total
1	Residential Customers						
2	Schedule 1- RS	44,639,052	5,139	1,017,555	3,980,464	0	4,998,019
3	Schedule 2- RSAE	394,372	29	5,726	33,269	0	38,995
4	Schedule RS- Residential Service	45,033,424	5,168	1,023,281	4,013,733	0	5,037,014
5							
6	Commercial and Industrial Customers						
7	Schedule 3- NRS	4,657,346	923	182,820	537,644	0	720,464
8	Schedule 3- NRH	6,256	1	198	986	0	1,184
9	Schedule 4- CS	28,611,970	386	148,363	955,068	997,920	2,101,351
10	Schedule 4- CSH	7,216	1	550	1,249	0	1,799
11	Schedule 5- IS	26,746,293	14	25,200	276,685	929,040	1,230,925
12		60,029,081	1,325	357,131	1,771,631	1,926,960	4,055,722
13							
14	Schedule 6- Municipal Street Lights	0	0	0	19,500	0	19,500
15	Schedule 7- Private Outdoor Lights	0	Not shown	0	93,892	0	93,892
16	Lighting	0	0	0	113,392	0	113,392
17							
18	Schedule 8- Exchange Utility	102,572	4	0	12,118	0	12,118
19							
20	TOTAL	105,165,077	6,497	$1,380,411	$5,910,874	$1,926,960	$9,218,245

Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026 (R)
Billing Units, Rates And Revenue At Proposed Rates
Fully Projected Future Test Year 2026

Line		Sch. 1- RS	Sch. 2- RSAE	Sch. 3- NRS	Sch. 3- NRH	Sch. 4- CS	Sch. 4- CSH	Sch. 5- IS	Sch. 6- MSL	Sch. 7- POL	Sch. 8- EU	Total
1						**BILLING UNITS**						
2	kWh Sales	44,639,052	394,372	4,657,346	6,256	28,611,970	7,216	26,746,293	0	0	102,572	105,165,077
3												
4	Number of Bills	61,670	347	11,080	12	4,632	12	168	0		48	77,969
5	Average Monthly Bills	5,139	29	923	1	386	1	14	0		4	6,497
6												
7						**Annual Billing Units- Public Lighting and Street Lighting**						
8	MV 20000 lumens								0	0		0
9	LED 50 OH								1,788	5,064		6,852
10	LED 50 UG								0	0		0
11	LED 50 UG Col								0	0		0
12	LED 70 OH								1,307	4,381		5,688
13	LED 70 UG								0	0		0
14	LED 140 OH								0	24		24
15	LED 140 UG								0	0		0
16									3,095	9,469		12,564
17						**RATES AND CHARGES**						
18						**Tariff Rates**						
19	Customer Charge	$16.50	$16.50	$16.50	$16.50	$32.03	$45.81	$150.00				Sch6 / Sch7 Lamps
20	Energy Block 1	$0.08917	$0.08436	$0.11544	$0.15758	$0.03338	$0.17313	$0.02825	$15.55	$10.17	$0.118140	MV 20000 lumens
21	Energy Block 2							$0.00182	$5.95	$9.61		LED 50 OH
22									$15.98	$12.76		LED 50 UG
23									$23.16	$18.50		LED 50 UG Col
24									$6.78	$10.26		LED 70 OH
25									$16.79	$13.41		LED 70 UG
26									$8.39	$11.56		LED 140 OH
27									$18.42	$14.72		LED 140 UG
28												
29	Demand Block 1					$9.24		$14.00				
30	Demand Block 2					140%		140%				
31												
32						**COMPUTATION OF REVENUE**						
33	Customer Charge Reven	1,017,555	5,726	182,820	198	148,363	550	25,200	0	0	0	1,380,411
34												
35	Distribution kWh Reven	3,980,464	33,269	537,644	986	955,068	1,249	276,685	19,500	93,892	12,118	5,910,874
36	Distribution Demand Revenue					997,920		929,040				1,926,960
37	*Total Distribution Rever*	3,980,464	33,269	537,644	986	1,952,988	1,249	1,205,725	19,500	93,892	12,118	7,837,834
38	**Total Revenue**	$4,998,019	$38,995	$720,464	$1,184	$2,101,351	$1,799	$1,230,925	$19,500	$93,892	$12,118	$9,218,245
39	Target Revenue	4,997,798	38,995	720,450	1,184	2,101,214	1,799	1,230,953	19,501	93,914	12,118	9,217,925
40						**BILLING UNITS- DETAIL**						
41	Block 1 kWh Sales	44,639,052	394,372	4,657,346	6,256	28,611,970	7,216	8,626,800	0	0	102,572	87,045,584
42	Block 2 kWh Sales							18,119,493				18,119,493
43												
44	Block 1 kW Demand					108,000		66,360				

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Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026 (R)
Proposed Revenue By Rate Class
Fully Projected Future Test Year 2026

Line	Account	Balance	RS	RSAE	NRS	NRH	CS	CSH	IS	MSL	POL	EU
	PRESENT RATES											
1	Distribution Revenue	6,369,121	3,357,674	24,383	490,753	676	1,510,082	1,028	880,700	13,496	81,371	8,957
2	Forfeited Disc / Other Rev	327,480	176,473	1,948	16,901	118	75,954	236	54,568	216	863	202
3	**Total Revenue**	6,696,602	3,534,147	26,332	507,654	794	1,586,036	1,264	935,269	13,713	82,234	9,159
4	Expenses	6,531,077	3,874,542	34,945	541,846	2,050	1,281,314	3,966	760,906	7,454	16,771	7,285
5	Net income	165,524	(340,395)	(8,613)	(34,191)	(1,256)	304,723	(2,702)	174,363	6,259	65,463	1,874
6	Rate Base	25,974,028	14,389,602	144,196	1,873,193	9,464	5,741,037	19,230	3,524,195	111,670	138,695	22,745
7	Return on Rate Base	0.64%	(2.37%)	(5.97%)	(1.83%)	(13.27%)	5.31%	(14.05%)	4.95%	5.60%	47.20%	8.24%
8	Relative Return	1.00 x	(3.71) x	(9.37) x	(2.86) x	(20.82) x	8.33 x	(22.05) x	7.76 x	8.80 x	74.07 x	12.93 x
9												
10	**FULLY ALLOCATED COST OF SERVICE**											
11	Distribution Revenue	9,217,925	5,394,391	50,324	745,060	3,113	1,856,321	6,142	1,106,414	19,193	27,310	9,656
12	Forfeited Disc / Other Revenue	327,480	176,473	1,948	16,901	118	75,954	236	54,568	216	863	202
13	Revenue Requirement	9,545,405	5,570,864	52,272	761,961	3,231	1,932,275	6,378	1,160,983	19,409	28,173	9,859
14												
15	Operating expenses	6,276,330	3,742,826	34,174	521,465	2,055	1,220,397	3,998	725,943	6,560	12,010	6,902
16	GRT	543,858	318,269	2,969	43,959	184	109,523	362	65,278	1,132	1,611	570
17	Income taxes	600,542	332,700	3,334	43,310	219	132,738	445	81,482	2,582	3,207	526
18	Net income	2,124,675	1,177,069	11,795	153,227	774	469,617	1,573	288,279	9,135	11,345	1,861
19	Return on Rate Base	8.18%	8.18%	8.18%	8.18%	8.18%	8.18%	8.18%	8.18%	8.18%	8.18%	8.18%
20	Revenue Increase Required	2,848,804	2,036,717	25,940	254,307	2,437	346,238	5,114	225,714	5,696	(54,060)	700
21	Revenue Increase %	42.54%	57.63%	98.51%	50.09%	306.81%	21.83%	404.58%	24.13%	41.54%	(65.74%)	7.64%
22												
23	**PROPOSED REVENUE ALLOCATION**											
24	Distribution Revenue	9,217,925	4,997,798	38,995	720,450	1,184	2,101,214	1,799	1,230,953	19,501	93,914	12,118
25	Other Revenue	327,480	176,473	1,948	16,901	118	75,954	236	54,568	216	863	202
26	Revenue Requirement	9,545,406	5,174,271	40,944	737,351	1,302	2,177,167	2,035	1,285,521	19,717	94,777	12,321
27												
28	Operating expenses	6,276,330	3,742,826	34,174	521,465	2,055	1,220,397	3,998	725,943	6,560	12,010	6,902
29	GRT	543,858	294,870	2,301	42,507	70	123,972	106	72,626	1,151	5,541	715
30	Income taxes	600,542	250,461	985	38,207	(181)	183,520	(456)	107,307	2,646	17,018	1,036
31	Net income	2,124,675	886,114	3,485	135,173	(642)	649,279	(1,613)	379,645	9,360	60,208	3,667
32	**Return on Rate Base**	**8.18%**	**6.16%**	**2.42%**	**7.22%**	**(6.78%)**	**11.31%**	**(8.39%)**	**10.77%**	**8.38%**	**43.41%**	**16.12%**
33	**Relative Return**	**1.00 x**	**0.75 x**	**0.30 x**	**0.88 x**	**(0.83) x**	**1.38 x**	**(1.03) x**	**1.32 x**	**1.02 x**	**5.31 x**	**1.97 x**
34	**Progress toward unity**		**95%**	**93%**	**97%**	**92%**	**95%**	**91%**	**95%**	**100%**	**94%**	**92%**
35												
36	**Proposed Distribution Increase**	**2,848,804**	**1,640,124**	**14,612**	**229,697**	**507**	**591,131**	**771**	**350,253**	**6,004**	**12,543**	**3,162**
37	**Revenue Increase %**	**44.7%**	**48.8%**	**59.9%**	**46.8%**	**75.0%**	**39.1%**	**75.0%**	**39.8%**	**44.5%**	**15.4%**	**35.3%**
38	Total Bill Revenue Increase (100% GSSR)	17.2%	21.4%	23.4%	24.4%	39.6%	13.8%	44.7%	10.1%	44.5%	15.4%	16.8%
39	Proposed Increase		48.85%	59.93%	46.81%	75.00%	39.15%	75.00%	39.77%	44.49%	15.41%	35.30%
40	% of Cost of Service	100%	93%	78%	97%	40%	113%	32%	111%	102%	336%	125%
41	**Subsidy given (received)**											
42	Present rates	(0)	(432,096)	(9,532)	(46,129)	(1,316)	268,137	(2,824)	151,904	5,547	64,579	1,729
43	Proposed revene allocation	(0)	(290,956)	(8,311)	(18,054)	(1,416)	179,662	(3,186)	91,366	226	48,863	1,806
44	**Reduction in subsidy**		**33%**	**13%**	**61%**	**(8%)**	**33%**	**(13%)**	**40%**	**96%**	**24%**	**(4%)**
45	Revenue Increase % Filed	19.5%	24.4%	28.1%	17.3%	28.8%	10.6%	28.6%	24.3%	1.2%	(19.9%)	25.8%
46	**Multiplier**	**0.951088**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**
47	**Relative increase**	**1.00 x**	**1.09 x**	**1.34 x**	**1.05 x**	**1.68 x**	**0.88 x**	**1.68 x**	**0.89 x**	**0.99 x**	**0.34 x**	**0.79 x**

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Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026 (R)

Summary Of Present And Proposed Rates
Fully Projected Future Test Year 2026

Line		Present Rates (excl GSSR)	Present Rates (incl GSSR present)	Proposed Rates (excl GSSR)	Proposed Rates (incl GSSR present)	Proposed Increase (excl GSSR)	Proposed Increase (incl GSSR present)
1	**Schedule RS- Residential Service**						
2	Customer Charge per Bill	$12.00	$12.00	$16.50	$16.50	37.5%	
3							
4	Energy Charge, per kWh- All	$0.058640	$0.15529	$0.089170	$0.18582	52.1%	19.7%
5	**Schedule RSAE- Residential Service All Electric**						
6	Customer Charge per Bill	$12.00	$12.00	$16.50	$16.50	37.5%	
7							
8	Energy Charge, per kWh- All	$0.051270	$0.14792	$0.084360	$0.18101	64.5%	22.4%
9	**Schedule NRS- Non-Residential Service**						
10	Customer Charge per Bill	$12.22	$12.22	$16.50	$16.50	35.0%	
11							
12	Energy Charge, per kWh- All	$0.076300	$0.17295	$0.115440	$0.21209	51.3%	22.6%
13	**Schedule NRH- Non-Residential Service Space Heating**						
14	Customer Charge per Bill	$12.22	$12.22	$16.50	$16.50	35.0%	
15							
16	Energy Charge, per kWh- All	$0.084690	$0.18134	$0.157580	$0.25423	86.1%	40.2%
17	**Schedule CS- Commercial Service (Minimum 7 kW)**						
18	Customer Charge per Bill	$32.03	$32.03	$32.03	$32.03	0.0%	
19							
20	Energy Charge, per kWh- All	$0.022680	$0.11933	$0.033380	$0.13003	47.2%	9.0%
21							
22	Demand Charge, per kW-Mth- All	$6.60	$6.60	$9.24	$9.24	40.0%	
23	**Schedule CSH- Commercial Service Space Heaters (Minimum 7 kW)**						
24	Customer Charge per Bill	$45.81	$45.81	$45.81	$45.81	0.0%	
25							
26	Energy Charge, per kWh- All	$0.066280	$0.16293	$0.173130	$0.26978	161.2%	65.6%
27	**Schedule IS- General Service (Minimum 2300 volts, 50 kW)**						
28	Customer Charge per Bill	$85.00	$85.00	$150.00	$150.00	76.5%	
29							
30	Energy Charge, per kWh						
31	First 130 kWh X Billed Demand kW	$0.02078	$0.11743	$0.02825	$0.12490	35.9%	6.4%
32	Additional kWh	$0.00130	$0.09795	$0.00182	$0.09847	40.0%	0.5%
33							
34	Demand Charge, per kW-Mth- All	$10.00	$10.00	$14.00	$14.00	40.0%	40.0%

Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026 (R)

Summary Of Present And Proposed Rates
Fully Projected Future Test Year 2026

Line		Present Rates (excl GSSR)	Present Rates (incl GSSR present)	Proposed Rates (excl GSSR)	Proposed Rates (incl GSSR present)	Proposed Increase (excl GSSR)	Proposed Increase (incl GSSR present)
35	**Schedules MSL, POL**						
36	Per Lamp per Month	MSL-Present	POL-Present	MSL- Proposed	POL-Proposed	MSL	POL
37		Excludes GSSR	Excludes GSSR	Excludes GSSR	Excludes GSSR		
38	20000 lumens (HG)	$10.76	$8.81	$15.55	$10.17	44.5%	15.4%
39							
40							
41							
42	LED 50W, 5000 lumens OH Cobra	$4.12	$8.33	$5.95	$9.61	44.4%	15.4%
43	LED 50W, 5000 lumens UG Cobra	$11.06	$11.06	$15.98	$12.76	44.5%	15.4%
44	LED 50W, 5000 lumens UG Colonial	$16.03	$16.03	$23.16	$18.50	44.5%	15.4%
45	LED 70W, 15000 lumens OH Cobra	$4.69	$8.89	$6.78	$10.26	44.6%	15.4%
46	LED 70W, 15000 lumens UG Cobra	$11.62	$11.62	$16.79	$13.41	44.5%	15.4%
47	LED 140W, 20000 lumens OH Cobra	$5.81	$10.02	$8.39	$11.56	44.4%	15.4%
48	LED 140W, 20000 lumens UG Cobra	$12.75	$12.75	$18.42	$14.72	44.5%	15.5%
49		**MSL, POL rates are Distribution only**		**MSL, POL rates are Distribution only**			
50	**Schedule EU- Exchange of Service**						
51	Energy Charge, per kWh- All	$0.08732	$0.18397	$0.118140	$0.21479	35.3%	16.8%

B8 (R)

Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026 (R)
Bill Comparisons (including GSSR present rate)
Fully Projected Future Test Year 2026

Schedule RS- Residential Service

			Present Rates		Proposed Rates		Proposed Increase	
	Average	Sales (kWh)	Monthly Bill	Cost per kWh	Monthly Bill	Cost per kWh	$ per Month	%
1		Minimum	$12.00		$16.50		$4.50	37.5%
2		1	12.16	$12.15529	16.69	$16.68582	4.53	37.3%
3		10	13.55	$1.35529	18.36	$1.83582	4.81	35.5%
4		100	27.53	$0.27529	35.08	$0.35082	7.55	27.4%
5		250	50.82	$0.20329	62.96	$0.25182	12.13	23.9%
6		500	89.65	$0.17929	109.41	$0.21882	19.77	22.1%
7	All Residential, annual	700	120.70	$0.17243	146.57	$0.20939	25.87	21.4%
8		1,000	167.29	$0.16729	202.32	$0.20232	35.03	20.9%
9		1,500	244.94	$0.16329	295.23	$0.19682	50.30	20.5%
10		2,000	322.58	$0.16129	388.14	$0.19407	65.56	20.3%
11		3,000	477.87	$0.15929	573.96	$0.19132	96.09	20.1%
12								

Schedule RSAE- Residential Service All Electric

			Present Rates		Proposed Rates		Proposed Increase	
	Average	Sales (kWh)	Monthly Bill	Cost per kWh	Monthly Bill	Cost per kWh	$ per Month	%
13		Minimum	$12.00		$16.50		$4.50	37.5%
14		1	12.15	$12.14792	16.68	$16.68101	4.53	37.3%
15		10	13.48	1.34792	18.31	1.83101	4.83	35.8%
16		100	26.79	0.26792	34.60	0.34601	7.81	29.2%
17		250	48.98	0.19592	61.75	0.24701	12.77	26.1%
18		500	85.96	0.17192	107.01	0.21401	21.05	24.5%
19		1,000	159.92	0.15992	197.51	0.19751	37.59	23.5%
20	All RSAE, annual	1,100	174.71	0.15883	215.61	0.19601	40.90	23.4%
21		1,500	233.88	0.15592	288.02	0.19201	54.14	23.2%
22		2,000	307.84	0.15392	378.52	0.18926	70.68	23.0%
23		3,000	455.76	0.15192	559.53	0.18651	103.77	22.8%
24								

B8 (R)

Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026 (R)
Bill Comparisons (including GSSR present rate)
Fully Projected Future Test Year 2026

Schedule NRS- Non-Residential Service

			Present Rates		Proposed Rates		Proposed Increase	
	Average	Sales (kWh)	Monthly Bill	Cost per kWh	Monthly Bill	Cost per kWh	$ per Month	%
25		Minimum	$12.22		$16.50		$4.28	35.0%
26		1	12.39	$12.39295	16.71	$16.71209	4.32	34.9%
27		50	20.87	0.41735	27.10	0.54209	6.24	29.9%
28		100	29.52	0.29515	37.71	0.37709	8.19	27.8%
29		250	55.46	0.22183	69.52	0.27809	14.07	25.4%
30	All NRS, annual	430	86.59	0.20137	107.70	0.25046	21.11	24.4%
31		1,000	185.17	0.18517	228.59	0.22859	43.42	23.5%
32		1,500	271.65	0.18110	334.64	0.22309	62.99	23.2%
33		2,000	358.12	0.17906	440.68	0.22034	82.56	23.1%
34		3,000	531.07	0.17702	652.77	0.21759	121.70	22.9%
35								

Schedule NRH- Non-Residential Service Space Heating

			Present Rates		Proposed Rates		Proposed Increase	
	Average	Sales (kWh)	Monthly Bill	Cost per kWh	Monthly Bill	Cost per kWh	$ per Month	%
36		Minimum	$12.22		$16.50		$4.28	35.0%
37		500	102.89	0.20578	143.62	0.28723	40.73	39.6%
38	All NRH, annual	670	133.72	0.19958	186.83	0.27886	53.12	39.7%
39		2,000	374.90	0.18745	524.96	0.26248	150.06	40.0%
40								

B8 (R)

Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026 (R)
Bill Comparisons (including GSSR present rate)
Fully Projected Future Test Year 2026

Schedule CS- Commercial Service (Minimum 7 kW)

			Present Rates		Proposed Rates		Proposed Increase	
		Sales (kWh)	Monthly Bill	Cost per kWh	Monthly Bill	Cost per kWh	$ per Month	%
41	**7 kW**	Minimum	78.23		96.71		18.48	23.6%
42	Load factor 10%	511	139.21	0.27242	163.16	0.31929	23.95	17.2%
43	Load factor 20%	1,022	200.19	0.19588	229.60	0.22466	29.42	14.7%
44	Load factor 35%	1,789	291.65	0.16307	329.27	0.18410	37.62	12.9%
45	Load factor 50%	2,555	383.12	0.14995	428.94	0.16788	45.82	12.0%
46	Load factor 60%	3,066	444.10	0.14485	495.38	0.16157	51.29	11.6%
47	Load factor 75%	3,833	535.56	0.13974	595.05	0.15526	59.49	11.1%
48								
49	**10 kW Demand**	Minimum	98.03		124.43		26.40	26.9%
50	Load factor 10%	730	185.14	0.25362	219.35	0.30048	34.21	18.5%
51	Load factor 20%	1,460	272.25	0.18647	314.27	0.21526	42.02	15.4%
52	Load factor 35%	2,555	402.92	0.15770	456.66	0.17873	53.74	13.3%
53	Load factor 50%	3,650	533.58	0.14619	599.04	0.16412	65.46	12.3%
54	Load factor 60%	4,380	620.70	0.14171	693.96	0.15844	73.27	11.8%
55	Load factor 75%	5,475	751.36	0.13724	836.34	0.15276	84.98	11.3%
56								
57	**25 kW Demand**	Minimum	197.03		263.03		66.00	33.5%
58	Load factor 10%	1,825	414.81	0.22729	500.33	0.27416	85.53	20.6%
59	Load factor 20%	3,650	632.58	0.17331	737.64	0.20209	105.06	16.6%
60	Load factor 35%	6,388	959.25	0.15018	1,093.60	0.17121	134.35	14.0%
61	Load factor 50%	9,125	1,285.92	0.14092	1,449.55	0.15886	163.64	12.7%
62	Load factor 60%	10,950	1,503.69	0.13732	1,686.86	0.15405	183.17	12.2%
63	Load factor 75%	13,688	1,830.36	0.13372	2,042.82	0.14925	212.46	11.6%
64								
65	**40 kW Demand**	Minimum	296.03		401.63		$105.60	35.7%
66	Load factor 10%	2,920	644.47	0.22071	781.32	0.26757	136.84	21.2%
67	Load factor 20%	5,840	992.92	0.17002	1,161.01	0.19880	168.09	16.9%
68	Load factor 35%	10,220	1,515.58	0.14830	1,730.54	0.16933	214.95	14.2%
69	Load factor 50%	14,600	2,038.25	0.13961	2,300.07	0.15754	261.82	12.9%
70	Load factor 60%	17,520	2,386.69	0.13623	2,679.76	0.15295	293.06	12.3%
71	Load factor 75%	21,900	2,909.36	0.13285	3,249.29	0.14837	339.93	11.7%

Schedule CSH- Commercial Service Space Heaters (Minimum 7 kW)

		Present Rates		Proposed Rates		Proposed Increase	
	Sales (kWh)	Monthly Bill	Cost per kWh	Monthly Bill	Cost per kWh	$ per Month	%
72	Minimum	$45.81		$45.81		$0.00	-
73	1,000	208.74	$0.20874	315.59	$0.31559	106.85	51.2%
74	24,000	3,956.13	0.16484	6,520.53	0.27169	2,564.40	64.8%

B8 (R)

Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026 (R)
Bill Comparisons (including GSSR present rate)
Fully Projected Future Test Year 2026

Schedule IS- General Service (Minimum 2300 volts, 50 kW)

			Sales (kWh)	Present Rates		Proposed Rates		Proposed Increase	
				Monthly Bill	Cost per kWh	Monthly Bill	Cost per kWh	$ per Month	%
75	**Monthly Minimum**			$1,585.00		$2,250.00		665.00	42.0%
76		**150 kW Demand**							
77	**Load Factors**		Minimum	$1,585.00		$2,250.00		665.00	42.0%
78		30%	32,850	5,182.52	0.15776	6,000.12	0.18265	817.61	15.8%
79		40%	43,800	6,255.07	0.14281	7,078.37	0.16161	823.30	13.2%
80		50%	54,750	7,327.62	0.13384	8,156.62	0.14898	829.00	11.3%
81		60%	65,700	8,400.18	0.12786	9,234.86	0.14056	834.69	9.9%
82		75%	82,125	10,009.00	0.12188	10,852.23	0.13214	843.23	8.4%
83									
84		**400 kW Demand**							
85	**Load Factors**		Minimum	$4,085.00		$5,750.00		1,665.00	40.8%
86		30%	87,600	13,678.38	0.15615	15,750.33	0.17980	2,071.95	15.2%
87		40%	116,800	16,538.52	0.14160	18,625.66	0.15947	2,087.14	12.6%
88		50%	146,000	19,398.66	0.13287	21,500.98	0.14727	2,102.32	10.8%
89		60%	175,200	22,258.80	0.12705	24,376.30	0.13913	2,117.50	9.5%
90		75%	219,000	26,549.01	0.12123	28,689.29	0.13100	2,140.28	8.1%
91									
92		**750 kW Demand**							
93	**Load Factors**		Minimum	$7,585.00		$10,650.00		3,065.00	40.4%
94		30%	164,250	25,572.59	0.15569	29,400.62	0.17900	3,828.04	15.0%
95		40%	219,000	30,935.35	0.14126	34,791.86	0.15887	3,856.51	12.5%
96		50%	273,750	36,298.11	0.13260	40,183.09	0.14679	3,884.98	10.7%
97		60%	328,500	41,660.88	0.12682	45,574.32	0.13873	3,913.45	9.4%
98		75%	410,625	49,705.02	0.12105	53,661.17	0.13068	3,956.15	8.0%
99									
100		**1500 kW Demand**							
101	**Load Factors**		Minimum	$15,085.00		$21,150.00		6,065.00	40.2%
102		30%	328,500	51,060.18	0.15543	58,651.25	0.17854	7,591.07	14.9%
103		40%	438,000	61,785.70	0.14106	69,433.71	0.15852	7,648.01	12.4%
104		50%	547,500	72,511.23	0.13244	80,216.18	0.14651	7,704.95	10.6%
105		60%	657,000	83,236.75	0.12669	90,998.64	0.13851	7,761.89	9.3%
106		75%	821,250	99,325.04	0.12094	107,172.34	0.13050	7,847.30	7.9%

B8-1 (R)

Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026 (R)
Bill Comparisons (excluding GSSR)
Fully Projected Future Test Year 2026
Schedule RS- Residential Service

			Present Rates		Proposed Rates		Proposed Increase	
	Average	Sales (kWh)	Monthly Bill	Cost per kWh	Monthly Bill	Cost per kWh	$ per Month	%
1		Minimum	$12.00		$16.50		$4.50	37.5%
2		1	12.06	$12.05864	16.59	$16.58917	4.53	37.6%
3		10	12.59	$1.25864	17.39	$1.73917	4.81	38.2%
4		100	17.86	$0.17864	25.42	$0.25417	7.55	42.3%
5		250	26.66	$0.10664	38.79	$0.15517	12.13	45.5%
6		500	41.32	$0.08264	61.09	$0.12217	19.77	47.8%
7	All Residential, annual	700	53.05	$0.07578	78.92	$0.11274	25.87	48.8%
8		1,000	70.64	$0.07064	105.67	$0.10567	35.03	49.6%
9		1,500	99.96	$0.06664	150.26	$0.10017	50.30	50.3%
10		2,000	129.28	$0.06464	194.84	$0.09742	65.56	50.7%
11		3,000	187.92	$0.06264	284.01	$0.09467	96.09	51.1%
12								

Schedule RSAE- Residential Service All Electric

			Present Rates		Proposed Rates		Proposed Increase	
	Average	Sales (kWh)	Monthly Bill	Cost per kWh	Monthly Bill	Cost per kWh	$ per Month	%
13		Minimum	$12.00		$16.50		$4.50	37.5%
14		1	12.05	$12.05127	16.58	$16.58436	4.53	37.6%
15		10	12.51	1.25127	17.34	1.73436	4.83	38.6%
16		100	17.13	0.17127	24.94	0.24936	7.81	45.6%
17		250	24.82	0.09927	37.59	0.15036	12.77	51.5%
18		500	37.64	0.07527	58.68	0.11736	21.05	55.9%
19		1,000	63.27	0.06327	100.86	0.10086	37.59	59.4%
20	All RSAE, annual	1,100	68.40	0.06218	109.30	0.09936	40.90	59.8%
21		1,500	88.91	0.05927	143.04	0.09536	54.14	60.9%
22		2,000	114.54	0.05727	185.22	0.09261	70.68	61.7%
23		3,000	165.81	0.05527	269.58	0.08986	103.77	62.6%
24								

B8-1 (R)

Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026 (R)
Bill Comparisons (excluding GSSR)
Fully Projected Future Test Year 2026
Schedule NRS- Non-Residential Service

			Present Rates		Proposed Rates		Proposed Increase	
	Average	Sales (kWh)	Monthly Bill	Cost per kWh	Monthly Bill	Cost per kWh	$ per Month	%
25		Minimum	$12.22		$16.50		$4.28	35.0%
26		1	12.30	$12.29630	16.62	$16.61544	4.32	35.1%
27		50	16.04	0.32070	22.27	0.44544	6.24	38.9%
28		100	19.85	0.19850	28.04	0.28044	8.19	41.3%
29		250	31.30	0.12518	45.36	0.18144	14.07	44.9%
30	All NRS, annual	430	45.03	0.10472	66.14	0.15381	21.11	46.9%
31		1,000	88.52	0.08852	131.94	0.13194	43.42	49.1%
32		1,500	126.67	0.08445	189.66	0.12644	62.99	49.7%
33		2,000	164.82	0.08241	247.38	0.12369	82.56	50.1%
34		3,000	241.12	0.08037	362.82	0.12094	121.70	50.5%
35								

Schedule NRH- Non-Residential Service Space Heating

			Present Rates		Proposed Rates		Proposed Increase	
	Average	Sales (kWh)	Monthly Bill	Cost per kWh	Monthly Bill	Cost per kWh	$ per Month	%
36		Minimum	$12.22		$16.50		$4.28	35.0%
37		500	54.57	0.10913	95.29	0.19058	40.73	74.6%
38	All NRH, annual	670	68.96	0.10293	122.08	0.18221	53.12	77.0%
39		2,000	181.60	0.09080	331.66	0.16583	150.06	82.6%
40								

B8-1 (R)

Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026 (R)
Bill Comparisons (excluding GSSR)
Fully Projected Future Test Year 2026
Schedule CS- Commercial Service (Minimum 7 kW)

			Present Rates		Proposed Rates		Proposed Increase	
		Sales (kWh)	Monthly Bill	Cost per kWh	Monthly Bill	Cost per kWh	$ per Month	%
41	**7 kW**	Minimum	78.23		96.71		18.48	23.6%
42	Load factor 10%	511	89.82	0.17577	113.77	0.22264	23.95	26.7%
43	Load factor 20%	1,022	101.41	0.09923	130.82	0.12801	29.42	29.0%
44	Load factor 35%	1,789	118.79	0.06642	156.41	0.08745	37.62	31.7%
45	Load factor 50%	2,555	136.18	0.05330	182.00	0.07123	45.82	33.7%
46	Load factor 60%	3,066	147.77	0.04820	199.05	0.06492	51.29	34.7%
47	Load factor 75%	3,833	165.15	0.04309	224.64	0.05861	59.49	36.0%
48								
49	**10 kW Demand**	Minimum	98.03		124.43		26.40	26.9%
50	Load factor 10%	730	114.59	0.15697	148.80	0.20383	34.21	29.9%
51	Load factor 20%	1,460	131.14	0.08982	173.16	0.11861	42.02	32.0%
52	Load factor 35%	2,555	155.98	0.06105	209.72	0.08208	53.74	34.5%
53	Load factor 50%	3,650	180.81	0.04954	246.27	0.06747	65.46	36.2%
54	Load factor 60%	4,380	197.37	0.04506	270.63	0.06179	73.27	37.1%
55	Load factor 75%	5,475	222.20	0.04059	307.19	0.05611	84.98	38.3%
56								
57	**25 kW Demand**	Minimum	197.03		263.03		66.00	33.5%
58	Load factor 10%	1,825	238.42	0.13064	323.95	0.17751	85.53	35.9%
59	Load factor 20%	3,650	279.81	0.07666	384.87	0.10544	105.06	37.5%
60	Load factor 35%	6,388	341.90	0.05353	476.24	0.07456	134.35	39.3%
61	Load factor 50%	9,125	403.99	0.04427	567.62	0.06221	163.64	40.5%
62	Load factor 60%	10,950	445.38	0.04067	628.54	0.05740	183.17	41.1%
63	Load factor 75%	13,688	507.46	0.03707	719.92	0.05260	212.46	41.9%
64								
65	**40 kW Demand**	Minimum	296.03		401.63		$105.60	35.7%
66	Load factor 10%	2,920	362.26	0.12406	499.10	0.17092	136.84	37.8%
67	Load factor 20%	5,840	428.48	0.07337	596.57	0.10215	168.09	39.2%
68	Load factor 35%	10,220	527.82	0.05165	742.77	0.07268	214.95	40.7%
69	Load factor 50%	14,600	627.16	0.04296	888.98	0.06089	261.82	41.8%
70	Load factor 60%	17,520	693.38	0.03958	986.45	0.05630	293.06	42.3%
71	Load factor 75%	21,900	792.72	0.03620	1,132.65	0.05172	339.93	42.9%

Schedule CSH- Commercial Service Space Heaters (Minimum 7 kW)

		Present Rates		Proposed Rates		Proposed Increase	
	Sales (kWh)	Monthly Bill	Cost per kWh	Monthly Bill	Cost per kWh	$ per Month	%
72	Minimum	$45.81		$45.81		$0.00	-
73	1,000	112.09	$0.11209	218.94	$0.21894	106.85	95.3%
74	24,000	1,636.53	0.06819	4,200.93	0.17504	2,564.40	156.7%

B8-1 (R)

Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026 (R)
Bill Comparisons (excluding GSSR)
Fully Projected Future Test Year 2026

Schedule IS- General Service (Minimum 2300 volts, 50 kW)

			Present Rates		Proposed Rates		Proposed Increase	
		Sales (kWh)	Monthly Bill	Cost per kWh	Monthly Bill	Cost per kWh	$ per Month	%
75	**Monthly Minimum**		$1,585.00		$2,250.00		665.00	42.0%
76		**150 kW Demand**						
77	**Load Factors**	Minimum	$1,585.00		$2,250.00		665.00	42.0%
78	30%	32,850	2,007.57	0.06111	2,825.17	0.08600	817.61	40.7%
79	40%	43,800	2,021.80	0.04616	2,845.10	0.06496	823.30	40.7%
80	50%	54,750	2,036.04	0.03719	2,865.03	0.05233	829.00	40.7%
81	60%	65,700	2,050.27	0.03121	2,884.96	0.04391	834.69	40.7%
82	75%	82,125	2,071.62	0.02523	2,914.85	0.03549	843.23	40.7%
83								
84		**400 kW Demand**						
85	**Load Factors**	Minimum	$4,085.00		$5,750.00		1,665.00	40.8%
86	30%	87,600	5,211.84	0.05950	7,283.79	0.08315	2,071.95	39.8%
87	40%	116,800	5,249.80	0.04495	7,336.94	0.06282	2,087.14	39.8%
88	50%	146,000	5,287.76	0.03622	7,390.08	0.05062	2,102.32	39.8%
89	60%	175,200	5,325.72	0.03040	7,443.22	0.04248	2,117.50	39.8%
90	75%	219,000	5,382.66	0.02458	7,522.94	0.03435	2,140.28	39.8%
91								
92		**750 kW Demand**						
93	**Load Factors**	Minimum	$7,585.00		$10,650.00		3,065.00	40.4%
94	30%	164,250	9,697.83	0.05904	13,525.86	0.08235	3,828.04	39.5%
95	40%	219,000	9,769.00	0.04461	13,625.51	0.06222	3,856.51	39.5%
96	50%	273,750	9,840.18	0.03595	13,725.15	0.05014	3,884.98	39.5%
97	60%	328,500	9,911.35	0.03017	13,824.80	0.04208	3,913.45	39.5%
98	75%	410,625	10,018.11	0.02440	13,974.26	0.03403	3,956.15	39.5%
99								
100		**1500 kW Demand**						
101	**Load Factors**	Minimum	$15,085.00		$21,150.00		6,065.00	40.2%
102	30%	328,500	19,310.65	0.05878	26,901.72	0.08189	7,591.07	39.3%
103	40%	438,000	19,453.00	0.04441	27,101.01	0.06187	7,648.01	39.3%
104	50%	547,500	19,595.35	0.03579	27,300.30	0.04986	7,704.95	39.3%
105	60%	657,000	19,737.70	0.03004	27,499.59	0.04186	7,761.89	39.3%
106	75%	821,250	19,951.23	0.02429	27,798.53	0.03385	7,847.30	39.3%

B8-2 (R)

Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026 (R)
Bill Comparisons (including GSSR effective June 1, 2025)
Fully Projected Future Test Year 2026

Schedule RS- Residential Service

			Present Rates		Proposed Rates		Proposed Increase	
	Average	Sales (kWh)	Monthly Bill	Cost per kWh	Monthly Bill	Cost per kWh	$ per Month	%
1		Minimum	$12.00		$16.50		$4.50	37.5%
2		1	12.19	$12.18679	16.72	$16.71732	4.53	37.2%
3		10	13.87	$1.38679	18.67	$1.86732	4.81	34.7%
4		100	30.68	$0.30679	38.23	$0.38232	7.55	24.6%
5		250	58.70	$0.23479	70.83	$0.28332	12.13	20.7%
6		500	105.40	$0.21079	125.16	$0.25032	19.77	18.8%
7	All Residential, annual	700	142.75	$0.20393	168.62	$0.24089	25.87	18.1%
8		1,000	198.79	$0.19879	233.82	$0.23382	35.03	17.6%
9		1,500	292.19	$0.19479	342.48	$0.22832	50.30	17.2%
10		2,000	385.58	$0.19279	451.14	$0.22557	65.56	17.0%
11		3,000	572.37	$0.19079	668.46	$0.22282	96.09	16.8%
12								

Schedule RSAE- Residential Service All Electric

			Present Rates		Proposed Rates		Proposed Increase	
	Average	Sales (kWh)	Monthly Bill	Cost per kWh	Monthly Bill	Cost per kWh	$ per Month	%
13		Minimum	$12.00		$16.50		$4.50	37.5%
14		1	12.18	$12.17942	16.71	$16.71251	4.53	37.2%
15		10	13.79	1.37942	18.63	1.86251	4.83	35.0%
16		100	29.94	0.29942	37.75	0.37751	7.81	26.1%
17		250	56.86	0.22742	69.63	0.27851	12.77	22.5%
18		500	101.71	0.20342	122.76	0.24551	21.05	20.7%
19		1,000	191.42	0.19142	229.01	0.22901	37.59	19.6%
20	All RSAE, annual	1,100	209.36	0.19033	250.26	0.22751	40.90	19.5%
21		1,500	281.13	0.18742	335.27	0.22351	54.14	19.3%
22		2,000	370.84	0.18542	441.52	0.22076	70.68	19.1%
23		3,000	550.26	0.18342	654.03	0.21801	103.77	18.9%
24								

B8-2 (R)

Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026 (R)
Bill Comparisons (including GSSR effective June 1, 2025)
Fully Projected Future Test Year 2026

Schedule NRS- Non-Residential Service

			Present Rates		Proposed Rates		Proposed Increase	
	Average	Sales (kWh)	Monthly Bill	Cost per kWh	Monthly Bill	Cost per kWh	$ per Month	%
25		Minimum	$12.22		$16.50		$4.28	35.0%
26		1	12.42	$12.42445	16.74	$16.74359	4.32	34.8%
27		50	22.44	0.44885	28.68	0.57359	6.24	27.8%
28		100	32.67	0.32665	40.86	0.40859	8.19	25.1%
29		250	63.33	0.25333	77.40	0.30959	14.07	22.2%
30	All NRS, annual	430	100.13	0.23287	121.24	0.28196	21.11	21.1%
31		1,000	216.67	0.21667	260.09	0.26009	43.42	20.0%
32		1,500	318.90	0.21260	381.89	0.25459	62.99	19.8%
33		2,000	421.12	0.21056	503.68	0.25184	82.56	19.6%
34		3,000	625.57	0.20852	747.27	0.24909	121.70	19.5%
35								

Schedule NRH- Non-Residential Service Space Heating

			Present Rates		Proposed Rates		Proposed Increase	
	Average	Sales (kWh)	Monthly Bill	Cost per kWh	Monthly Bill	Cost per kWh	$ per Month	%
36		Minimum	$12.22		$16.50		$4.28	35.0%
37		500	118.64	0.23728	159.37	0.31873	40.73	34.3%
38	All NRH, annual	670	154.82	0.23108	207.94	0.31036	53.12	34.3%
39		2,000	437.90	0.21895	587.96	0.29398	150.06	34.3%
40								

B8-2 (R)

Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026 (R)
Bill Comparisons (including GSSR effective June 1, 2025)
Fully Projected Future Test Year 2026

Schedule CS- Commercial Service (Minimum 7 kW)

			Present Rates		Proposed Rates		Proposed Increase	
		Sales (kWh)	Monthly Bill	Cost per kWh	Monthly Bill	Cost per kWh	$ per Month	%
41	**7 kW**	Minimum	78.23		96.71		18.48	23.6%
42	Load factor 10%	511	155.30	0.30392	179.25	0.35079	23.95	15.4%
43	Load factor 20%	1,022	232.38	0.22738	261.79	0.25616	29.42	12.7%
44	Load factor 35%	1,789	347.99	0.19457	385.61	0.21560	37.62	10.8%
45	Load factor 50%	2,555	463.60	0.18145	509.42	0.19938	45.82	9.9%
46	Load factor 60%	3,066	540.67	0.17635	591.96	0.19307	51.29	9.5%
47	Load factor 75%	3,833	656.29	0.17124	715.77	0.18676	59.49	9.1%
48								
49	**10 kW Demand**	Minimum	98.03		124.43		26.40	26.9%
50	Load factor 10%	730	208.14	0.28512	242.35	0.33198	34.21	16.4%
51	Load factor 20%	1,460	318.24	0.21797	360.26	0.24676	42.02	13.2%
52	Load factor 35%	2,555	483.40	0.18920	537.14	0.21023	53.74	11.1%
53	Load factor 50%	3,650	648.56	0.17769	714.01	0.19562	65.46	10.1%
54	Load factor 60%	4,380	758.67	0.17321	831.93	0.18994	73.27	9.7%
55	Load factor 75%	5,475	923.82	0.16874	1,008.81	0.18426	84.98	9.2%
56								
57	**25 kW Demand**	Minimum	197.03		263.03		66.00	33.5%
58	Load factor 10%	1,825	472.29	0.25879	557.82	0.30566	85.53	18.1%
59	Load factor 20%	3,650	747.56	0.20481	852.61	0.23359	105.06	14.1%
60	Load factor 35%	6,388	1,160.46	0.18168	1,294.80	0.20271	134.35	11.6%
61	Load factor 50%	9,125	1,573.35	0.17242	1,736.99	0.19036	163.64	10.4%
62	Load factor 60%	10,950	1,848.62	0.16882	2,031.78	0.18555	183.17	9.9%
63	Load factor 75%	13,688	2,261.52	0.16522	2,473.97	0.18075	212.46	9.4%
64								
65	**40 kW Demand**	Minimum	296.03		401.63		$105.60	35.7%
66	Load factor 10%	2,920	736.45	0.25221	873.30	0.29907	136.84	18.6%
67	Load factor 20%	5,840	1,176.88	0.20152	1,344.97	0.23030	168.09	14.3%
68	Load factor 35%	10,220	1,837.51	0.17980	2,052.47	0.20083	214.95	11.7%
69	Load factor 50%	14,600	2,498.15	0.17111	2,759.97	0.18904	261.82	10.5%
70	Load factor 60%	17,520	2,938.57	0.16773	3,231.64	0.18445	293.06	10.0%
71	Load factor 75%	21,900	3,599.21	0.16435	3,939.14	0.17987	339.93	9.4%

Schedule CSH- Commercial Service Space Heaters (Minimum 7 kW)

		Present Rates		Proposed Rates		Proposed Increase	
	Sales (kWh)	Monthly Bill	Cost per kWh	Monthly Bill	Cost per kWh	$ per Month	%
72	Minimum	$45.81		$45.81		$0.00	-
73	1,000	240.24	$0.24024	347.09	$0.34709	106.85	44.5%
74	24,000	4,712.13	0.19634	7,276.53	0.30319	2,564.40	54.4%

B8-2 (R)

Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026 (R)
Bill Comparisons (including GSSR effective June 1, 2025)
Fully Projected Future Test Year 2026

Schedule IS- General Service (Minimum 2300 volts, 50 kW)

			Sales (kWh)	Present Rates		Proposed Rates		Proposed Increase	
				Monthly Bill	Cost per kWh	Monthly Bill	Cost per kWh	$ per Month	%
75	**Monthly Minimum**			$1,585.00		$2,250.00		665.00	42.0%
76		**150 kW Demand**							
77	**Load Factors**		Minimum	$1,585.00		$2,250.00		665.00	42.0%
78		30%	32,850	6,217.29	0.18926	7,034.90	0.21415	817.61	13.2%
79		40%	43,800	7,634.77	0.17431	8,458.07	0.19311	823.30	10.8%
80		50%	54,750	9,052.25	0.16534	9,881.24	0.18048	828.99	9.2%
81		60%	65,700	10,469.73	0.15936	11,304.41	0.17206	834.69	8.0%
82		75%	82,125	12,595.94	0.15338	13,439.17	0.16364	843.23	6.7%
83									
84		**400 kW Demand**							
85	**Load Factors**		Minimum	$4,085.00		$5,750.00		1,665.00	40.8%
86		30%	87,600	16,437.78	0.18765	18,509.73	0.21130	2,071.95	12.6%
87		40%	116,800	20,217.72	0.17310	22,304.86	0.19097	2,087.14	10.3%
88		50%	146,000	23,997.66	0.16437	26,099.98	0.17877	2,102.32	8.8%
89		60%	175,200	27,777.60	0.15855	29,895.10	0.17063	2,117.50	7.6%
90		75%	219,000	33,447.51	0.15273	35,587.79	0.16250	2,140.28	6.4%
91									
92		**750 kW Demand**							
93	**Load Factors**		Minimum	$7,585.00		$10,650.00		3,065.00	40.4%
94		30%	164,250	30,746.46	0.18719	34,574.50	0.21050	3,828.04	12.5%
95		40%	219,000	37,833.85	0.17276	41,690.36	0.19037	3,856.51	10.2%
96		50%	273,750	44,921.24	0.16410	48,806.21	0.17829	3,884.98	8.7%
97		60%	328,500	52,008.63	0.15832	55,922.07	0.17023	3,913.45	7.5%
98		75%	410,625	62,639.71	0.15255	66,595.86	0.16218	3,956.15	6.3%
99									
100		**1500 kW Demand**							
101	**Load Factors**		Minimum	$15,085.00		$21,150.00		6,065.00	40.2%
102		30%	328,500	61,407.93	0.18693	68,999.00	0.21004	7,591.07	12.4%
103		40%	438,000	75,582.70	0.17256	83,230.71	0.19002	7,648.01	10.1%
104		50%	547,500	89,757.48	0.16394	97,462.43	0.17801	7,704.95	8.6%
105		60%	657,000	103,932.25	0.15819	111,694.14	0.17001	7,761.89	7.5%
106		75%	821,250	125,194.41	0.15244	133,041.71	0.16200	7,847.30	6.3%

C1 (R)

Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026 (R)

Net Operating Income And Rates of Return
HY 2024, FTY 2025 and FPFTY 2026
Answer to 52 Pa. Code 53.52 c[1]

Line	Description	HY 2024		Present Rates 12/31/2025	(A) Present Rates Fully Projected 12/31/2026	Proposed Rates Fully Projected 12/31/2026	Year 2023	Year 2022	(B) Proposed Rates Fully Projected 12/31/2020	(A)-(B) Change from Prior Order
		Per Books	Distribution Only	Distribution Only	Distribution Only	Distribution Only	Per Books	Per Books	Settlement Prior	
1	**REVENUE**									
2	Residential	$6,829,521	$3,190,200	$3,382,268	$3,382,057	$5,037,014			$3,261,637	$120,420
3	Commercial and industrial	5,657,570	2,642,167	2,876,554	2,883,240	4,055,722			2,708,336	174,905
4	Lighting	100,851	95,243	94,867	94,867	113,392			90,112	4,755
5	Sales for resale	17,863	8,957	8,957	8,957	12,118			9,732	(776)
6	Rounding								200	(200)
7	Electric operating revenue	12,605,805	5,936,568	6,362,646	6,369,121	9,217,925			6,070,017	299,105
8	Other revenue, net	318,497	318,497	320,568	327,480	327,480			116,459	211,021
9	Under (over) Collections	234,090	0	0	0	0			0	0
10	Total Revenue	13,158,392	6,255,065	6,683,214	6,696,602	9,545,406	14,712,539	13,942,718	6,186,476	510,126
11	*Annual kWH*	*97,019,287*	*97,019,287*	*103,979,075*	*105,165,077*	*105,165,077*			*107,825,923*	*(10,806,636)*
12	**EXPENSES**				Increase	2,848,804				
13	Purchased electricity	5,720,438					8,108,800	7,073,376		
14	Distribution	1,334,849	1,334,849	1,561,937	1,602,629	1,602,629	1,278,988	1,263,967	1,285,908	316,721
15	Customer accounting & collection expen	929,410	929,410	1,050,953	1,084,054	1,084,054	896,839	771,347	649,803	434,251
16	Sales expense, Public relations	3,171	3,171	19,727	9,737	9,737	5	79,104	8,915	822
17	Administrative & general expenses	1,264,200	1,264,200	1,451,824	1,596,359	1,596,359	1,142,464	1,118,660	929,641	666,718
18	Total Operating expenses	9,252,068	3,531,630	4,084,441	4,292,779	4,292,779	11,427,096	10,306,453	2,874,267	1,418,512
19										
20	Depreciation expense	1,335,247	1,335,247	1,844,192	1,939,404	1,939,404	1,155,288	1,132,021	1,331,977	607,427
21	Taxes other than income	814,557	394,406	419,544	419,926	590,990	857,783	764,006	377,878	42,049
22	Rate case expense amortization								108,667	(108,667)
23	Total Expenses	11,401,872	5,261,283	6,348,178	6,652,109	6,823,172	13,440,167	12,202,480	4,692,789	1,959,320
24										
25	Net operating income before income t	1,756,519	993,782	335,036	44,493	2,722,233	1,272,372	1,740,238	1,493,687	(1,449,194)
26										
27	Income tax expense	176,086	(35,246)	(45,332)	(121,031)	599,739	208,970	373,110	447,548	(568,580)
28	NET UTILITY OPERATING INCOME (LOSS) (A)	$1,580,433	$1,029,028	$380,368	$165,524	$2,122,494	$1,063,402	$1,367,128	$1,046,139	($880,614)
29						0.0817160				
30	RATE BASE (B)		$26,158,978	$26,213,538	$25,974,028	$25,974,028	$21,351,894	$17,402,137	$14,653,172	$11,505,806
31	RATE OF RETURN ON RATE BASE (A / B)		3.93%	1.45%	0.64%	8.17%	4.98%	7.86%	7.14%	

Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026 (R)

Net Operating Income And Rates of Return
HY 2024, FTY 2025 and FPFTY 2026
Answer to 52 Pa. Code 53.52 c[1] - Support Sheet No. 1
Support Sheet No. 1- Operating Expense and Going-Level Adjustments

Line	Acct.	Account Description	Year 2023	HY 2024	Changes	FTY 2025	Changes to FPFTY 2026	FPFTY 2026	Labor Year 2023	Labor HY 2024	Labor FTY 2025	Labor FPFTY 2026	12/31/2022	Labor 12/31/2022
1		Power Supply Expenses:												
2	555	Power Purchased	$0	$0	$0	$0	$0	$0					$0	
3		*Total Power Supply expense*	0	0	0	0	0	0	0	0	0	0	0	
4														
5		Distribution Expenses												
6	580	Operations Supv & Eng	0	8,121	(8,121)	0	0	0	0	4,043	0	0	0	0
7	582	Station Expense	0	0	0	0	0	0	0	0	0	0	74	0
8	583	Overhead Line Expense	686	770	5,024	5,794	225	6,020	(2,379)	(1,766)	3,980	4,098	6,666	2,690
9	585	Street Lighting Expense	675	146	113	259	9	267	0	127	178	182	0	0
10	586	Meter Expense	33,644	36,983	1,462	38,445	1,458	39,903	19,146	21,287	26,220	26,981	41,055	26,177
11	587	Customer Installation Expense	0	206	52	259	9	267	0	109	178	182	0	0
12	588	Miscellaneous Distribution Exp	170,671	173,944	106,478	280,422	5,267	285,688	86,318	91,107	136,556	140,466	201,683	95,999
13	589	Rents	30,717	32,950	2,350	35,300	0	35,300	0	0	0	0	32,397	0
14		*Total Operating expense*	236,392	253,121	107,357	360,478	6,968	367,446	103,085	114,906	167,111	171,910	281,874	124,866
15														
16	590	Maint Supv & Eng	85,710	97,875	2,896	100,771	1,013	101,784	37,403	41,204	41,076	42,663	68,775	28,189
17	591	Maint of Structures	1,848	0	0	0	0	0	792	0	0	0	687	449
18	592	Maintenance of Station Equipment	5,697	3,210	1,361	4,571	13,986	18,557	3,834	1,589	1,869	1,924	9,392	4,985
19	593	Maintenance of Overhead Lines	836,769	869,788	99,284	969,072	16,255	985,327	235,059	230,070	306,503	314,995	762,068	149,355
20	594	Maintenance of Underground Lines	28,436	30,206	9,850	40,056	257	40,313	3,598	4,482	4,503	4,638	48,060	21,694
21	595	Maintain Line Transformers	5,677	14,532	(6,659)	7,873	191	8,064	1,742	3,059	3,347	3,447	8,898	4,142
22	596	Maint. Street Light & Signal Expens	2,991	1,612	(704)	907	35	942	1,700	962	623	641	4,239	2,414
23	597	Maintenance of Misc. Distrib Plant	75,467	64,505	13,702	78,208	1,987	80,194	63,480	56,551	35,036	36,073	79,973	66,333
24		*Total Maintenance expense*	1,042,595	1,081,729	119,730	1,201,459	33,723	1,235,182	347,607	337,918	392,958	404,383	982,093	277,563
25		*Total Operating & Maintenance exp*	1,278,988	1,334,849	227,088	1,561,937	40,692	1,602,629	450,692	452,824	560,069	576,293	1,263,967	402,429
26														
27		Customer Accounting & Collection Expenses:												
28	902	Meter Reading Expense	19,808	21,775	(5,853)	15,922	622	16,544	10,767	12,359	10,936	11,261	18,616	11,805
29	903	Customer Records & Collection Exp	872,949	907,634	107,397	1,015,031	32,479	1,047,510	307,531	309,910	330,520	353,116	727,809	228,086
30	904	Uncollectible Accounts	0	0	20,000	20,000	0	20,000	0	0	0	0	19,667	0
31		*Total Customer Accting & Coll. exp*	892,757	929,410	121,544	1,050,953	33,101	1,084,054	318,298	322,269	341,456	364,377	766,092	239,892
32														

Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026 (R)

Net Operating Income And Rates of Return
HY 2024, FTY 2025 and FPFTY 2026
Answer to 52 Pa. Code 53.52 c[1] - Support Sheet No. 1
Support Sheet No. 1- Operating Expense and Going-Level Adjustments

Line	Acct.	Account Description	Year 2023	HY 2024	Changes	FTY 2025	Changes to FPFTY 2026	FPFTY 2026	Labor Year 2023	Labor HY 2024	Labor FTY 2025	Labor FPFTY 2026	12/31/2022	Labor 12/31/2022
33		Sales expense, Public relations												
34	908-913	Safety and Communications	4,082	3,171	16,555	19,727	(9,990)	9,737	1,735	180	156	161	5,255	804
35														
36		Administrative & General Expenses:												
37	920	Administrative & General Salaries	652,639	757,901	111,995	869,897	41,333	911,229	301,608	355,049	401,562	426,497	628,735	282,394
38	921	Office Supplies & Expenses	61,925	112,900	10,107	123,007	(13,297)	109,710	0	0	0	0	65,097	0
39	923	Outside Services Employed	87,889	137,115	17,410	154,525	0	154,525	0	0	0	0	74,357	0
40	924	Property Insurance	51,268	53,098	8,312	61,410	0	61,410	0	0	0	0	48,306	0
41	926	Employee Pensions & Benefits	0	0	0	0	0	0	0	0	0	0	1,084	0
42	928	Regulatory commission expenses	68,366	42,985	15	43,000	110,393	153,393	0	0	0	0	144,822	0
43	930	Miscellaneous General Expense	105,355	84,404	15,347	99,751	10,830	110,581	3,074	0	3,100	3,100	95,474	2,915
44	931	Rents	2,442	3,611	(1,411)	2,200	0	2,200	0	0	0	0	2,437	0
45	932	Maintenance of General Property	112,580	72,186	25,849	98,034	(4,723)	93,311	50,565	11,364	12,378	12,746	58,348	9,478
46		*Total Administrative & General exp*	1,142,464	1,264,200	187,624	1,451,824	144,535	1,596,359	355,248	366,413	417,040	442,344	1,118,660	294,787
47														
48		**Total Operating & Maintenance E**	**$3,318,291**	**$3,531,630**	**$552,811**	**$4,084,441**	**$208,337**	**$4,292,779**	#########	#########	#########	#########	**$3,153,973**	**$937,912**
49			$3,318,291	$3,531,630	552,811	$4,084,441	208,337	$4,292,779	1,125,972	1,141,685	1,318,721	1,383,174	3,153,973	937,912

C1-2 (R)

Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026 (R)

Support Sheet No. 2- Summary of Cost of Capital and Fair Rate of Return Based upon a Hypothetical Ratemaking Capital Structure
12/31/2025 and 12/31/2026

Line	Type of Capital	Ratios (1)	Cost Rate		Weighted Cost Rate
1	Long-Term Debt	51.06%	4.850%		2.47641%
2	Short-Term Debt				0.00%
3	Total Debt	51.06%			2.48%
4					
5	Preferred Stock				0.00000%
6	Common Equity	48.94%	11.65%	9.2300%	5.70151%
7	Total	100.00%	9.31%		8.17792%
8				Target ROR	8.18%
9					
10	[1] Recommended hypothetical capital structure ratios as discussed in direct testimony.				
11					2,848,804

C1-3 (R)

Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026 (R)

Net Operating Income And Rates of Return
HY 2024, FTY 2025 and FPFTY 2026
Answer to 52 Pa. Code 53.52 c[1]
Support Sheet No. 3- Taxes Other Than Income

Line			HY 2024		Present Rates Year Ended 12/31/2025	Present Rates Future Test Year Ended 12/31/2026	Proposed Rates Future Test Year Ended 12/31/2026	Year 2023	Year 2022
			Per Books	Distribution Only	Distribution Only	Distribution Only	Distribution Only	Distribution Only	Distribution Only
1	Taxes other than income:								
2	Pennsylvania Use Tax		$837	$837	$837	$837	$837	$908	$732
3	PUC Assessment			0	0	0	0		
4	Lease Tax		(10,663)					3,743	3,327
5	Public Utility Realty Tax (including surcharge		43,311	43,311	43,311	43,311	43,311	40,764	40,951
6	Pennsylvania Gross Receipts Tax		781,072	350,258	375,396	375,778	546,842	812,368	718,996
7			$814,557	$394,406	$419,544	$419,926	$590,990	$857,783	$764,006
8									
9	**Gross Receipts Tax**								
10	Electric operating revenue		$12,605,805	$5,936,568	$6,362,646	$6,369,121	$9,268,510	14,712,539	13,942,718
11									
12									
13	Gross Receipts Taxable		$12,605,805	$5,936,568	$6,362,646	$6,369,121	$9,268,510	$14,712,539	$13,942,718
14	Gross Receipts Tax at Present Rate	5.90%	$743,742	$350,258	$375,396	$375,778	$546,842	$868,040	$822,620
15	Rounding difference		37,330					(55,672)	(103,624)
16	Gross Receipts Tax expense		$781,072	$350,258	$375,396	$375,778	$546,842	$812,368	$718,996
17									
18	**Normalized Rate case expense**								
19	Estimated expenses					$331,178			
20	Amortization period (years)					3			
21	Normalized Rate case expense					$110,393	$110,393		

C1-4 (R)

Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026 (R)

C1-4

Net Operating Income And Rates of Return
HY 2024, FTY 2025 and FPFTY 2026
Answer to 52 Pa. Code 53.52 c[1]
Support Sheet No. 4- Income Tax Calculations

Line	Description		HY 2024		Present Rates 12/31/2025	Present Rates Fully Projected	Proposed Rates Fully Projected 12/31/2026	Year 2023	Year 2022
			Per Books	Distribution Only	Distribution Only	Distribution Only	Distribution Only		
1	Net Operating Income Excluding Income Taxes		$1,756,519	$993,782	$335,036	$44,493	$2,722,233	$1,272,372	$1,740,238
2									
3	Synchronized interest expense:								
4	Rate base		26,158,978	26,158,978	26,213,538	25,974,028	25,974,028	21,351,894	17,402,137
5									
6	Rate base for interest compuation		26,158,978	26,158,978	26,213,538	25,974,028	25,974,028	21,351,894	17,402,137
7	Weighted Cost of debt		2.476%	2.476%	2.476%	2.476%	2.476%	2.476%	2.476%
8	Synchronized interest expense		647,804	647,804	649,155	643,223	643,223	528,760	430,948
9	Taxable income before depreciation tax adjustments		1,108,716	345,978	(314,118)	(598,730)	2,079,010	743,612	1,309,290
10									
11	Pennsylvania depreciation adjustment:								
12	Tax depreciation (using DDB method)		(2,466,799)	(2,466,799)	(2,176,619)	(2,195,614)	(2,195,614)		
13	Book depreciation		1,335,247	1,335,247	1,844,192	1,939,404	1,939,404		
14	Pennsylvania depreciation adjustment		(1,131,552)	(1,131,552)	(332,427)	(256,211)	(256,211)	0	0
15	Pennsylvania taxable income		(22,836)	(785,574)	(646,545)	(854,941)	1,822,799	743,612	1,309,290
16	Regulatory Pennsylvania income tax expense	9.99%	(1,939)	(66,695)	(51,659)	(64,035)	136,528	66,851	124,252
17		8.99%	8.49%	8.49%	7.99%	7.49%	7.49%	8.99%	9.49%
18	Federal depreciation adjustment:								
19	Tax depreciation (using SL method)		(1,598,164)	(1,598,164)	(1,551,605)	(1,676,119)	(1,676,119)		
20	Book depreciation		1,335,247	1,335,247	1,844,192	1,939,404	1,939,404		
21	Federal depreciation adjustment		(262,917)	(262,917)	292,587	263,285	263,285	0	0
22									
23	Taxable income before depreciation tax adjustments		1,108,716	345,978	(314,118)	(598,730)	2,079,010	743,612	1,309,290
24	Federal depreciation adjustment		(262,917)	(262,917)	292,587	263,285	263,285	0	0
25	Pennsylvania income tax expense		1,939	66,695	51,659	64,035	(136,528)	(66,851)	(124,252)
26	Federal taxable income		847,738	149,756	30,128	(271,410)	2,205,767	676,761	1,185,038
27	Regulatory Federal income tax expense	21.00%	178,025	31,449	6,327	(56,996)	463,211	142,120	248,858
28									
29	Regulatory Total income tax expense		$176,086	($35,246)	($45,332)	($121,031)	$599,739	$208,970	$373,110
30									
31	Deferred Federal Income Tax expense (included in above):								
32	Tax depreciation (using SL method)		1,598,164	1,598,164	1,551,605	1,676,119	1,676,119		
33	Tax depreciation (using DDB method)		2,466,799	2,466,799	2,176,619	2,195,614	2,195,614		
34			868,635	868,635	625,014	519,496	519,496		
35	Federal tax rate		21.00%	21.00%	21.00%	21.00%	21.00%		
36	Deferred Federal income tax (credit)		$182,413	$182,413	$131,253	$109,094	$109,094		
37	Combined statutory tax rate	28.89%	27.71%	27.71%	27.31%	26.92%	26.92%		

C1-5 (R)

Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026 (R)

Net Operating Income And Rates of Return
HY 2024, FTY 2025 and FPFTY 2026
Answer to 52 Pa. Code 53.52 c[1]
Support Sheet No. 5- Computation of Rate Base

Line	Description		HY 2024	FTY 2025	FPFTY 2026	Year 2023	Year 2022
1	**Utility Plant in Service**						
2	Assets	Sch. C3 (R), line 23	$ 41,101,936	$ 42,831,436	$ 44,666,856	$ 36,030,374	$ 31,686,610
3	Less: Accumulated Depreciation	Sch. C3 (R), line 23	(15,226,786)	(17,226,319)	(19,321,064)	(15,048,529)	(14,733,579)
4			25,875,150	25,605,116	25,345,792	20,981,845	16,953,031
5							
6	Less: Accumulated deferred income taxes (ADIT)	Line 32	96,455	19,318	(38,728)	96,455	96,455
7							
8	Less: Customer deposits	Sch. C2 (R), line 52	(195,713)	(195,713)	(120,033)	(164,443)	(157,003)
9	Accrued Pension / OPEB Liability	Line 47	(300,708)	28,827	(28,013)	(308,290)	(335,745)
10	Materials & Supplies	Sch. C2 (R), line 22	247,983	247,983	302,296	334,040	441,264
11			25,723,167	25,705,531	25,461,314	20,939,607	16,998,002
12	Cash Working Capital Allowance	Line 25	435,811	508,007	512,714	412,287	404,135
13	RATE BASE		$ 26,158,978	$ 26,213,538	$ 25,974,028	$ 21,351,894	$ 17,402,137
14							
15	**Cash Working Capital Allowance:**						
16	Operating Expenses	Sch. C1 (R), line 23	$ 5,261,283	$ 6,348,178	$ 6,652,109	$ 5,331,367	$ 5,129,104
17							
18	Deductions:						
19	Taxes Oher Than Income	Sch. C1-3 (R), line 7	419,544	419,926	590,990	857,783	764,006
20	Uncollectible accounts	Sch. C1-1 (R), line 30	20,000	20,000	20,000	20,000	0
21	Depreciation Expense	Sch. C1 (R), line 20	1,335,247	1,844,192	1,939,404	1,155,288	1,132,021
22	Total Deductions		1,774,791	2,284,119	2,550,394	2,033,071	1,896,027
23	Cash Operating Expenses		3,486,492	4,064,059	4,101,715	3,298,296	3,233,077
24	Cash Operating Expenses Ratio		1/8	1/8	1/8	1/8	1/8
25	Cash Working Capital Allowance (A plus B)		$ 435,811	$ 508,007	$ 512,714	$ 412,287	$ 404,135
26							
27	Regulatory Accumluated deferred income tax:						
28	Accumulated depreciation based on tax expense borne by ratepayers		26,630,508	28,182,113	29,858,231		
29	Accumulated depreciation based on taxes paid by company		26,171,198	28,090,123	30,042,650		
30	(Higher) depreciation taken by company		459,310	91,990	(184,419)		
31	Federal tax rate		21.00%	21.00%	21.00%		
32	Regulatory Accumluated deferred income tax (liability)		96,455	19,318	(38,728)		
34	Excess deferred income tax:(EDIT)	NOT USED					
41							
42	Regulatoy (Liability) and Assets						
43	Accrued postretirement cost (Liability)		(185,579)	(185,579)	(185,579)	(190,178)	(259,836)
44	Regulatoy (Liability)		(230,379)	(230,379)	(230,379)	(243,375)	(212,327)
45	Regulatory Assets			331,178	275,981		
46	Deferred tax asset related to OPEB		115,250	113,607	111,964	125,263	136,418
47			(300,708)	28,827	(28,013)	(308,290)	(335,745)

C2 (R)

Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026 (R)

Balance Sheets
12/31/2024, 12/31/2025 and 12/31/2026
Answer to 52 Pa. Code 53.52 c[2]

Line	Account Title	Per Books 12/31/2024	Pro Forma 12/31/2025	Pro Forma 12/31/2026
1	**Assets and Other Debits**			
2	Utility Plant			
3	Electric plant in service	$41,101,936	$42,831,436	$44,666,856
4	Construction work in progress	27,017	27,017	27,017
5	Accumulated depreciation	(15,226,786)	(17,226,319)	(19,321,064)
6	*Total utility plant*	25,902,167	25,632,133	25,372,809
7				
8	Other Property and Investments:			
9	Non-utility property	144,043	144,043	144,043
10	Regulatory asset	40,145	40,145	40,145
11	Regulatory asset- RS Plan		0	0
12	Rentals and other	65,176	65,176	65,176
13	*Total other property and investments*	249,364	249,364	249,364
14				
15	Current Assets:			
16	Cash	203,335	203,335	203,335
17	Customer accounts receivable	1,198,530	1,198,530	1,198,530
18	Provison for uncollectible accounts	(12,306)	(12,306)	(12,306)
19	Accrued utility revenues	667,515	667,515	667,515
20	Other accounts receivable	287,005	287,005	287,005
21	Advances to affiliates	49,000	49,000	49,000
22	Inventories	247,983	247,983	247,983
23	Prepayments	8,439	8,439	8,439
24	Prepaid Costs	108,863	108,863	108,863
25	GSSR Under (Over)	72,766	72,766	72,766
26	*Total current assets*	2,831,130	2,831,130	2,831,130
27				
28	**Total Assets and Other Debits**	**$28,982,661**	**$28,712,627**	**$28,453,303**
29				

C2 (R)

Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026 (R)

Balance Sheets
12/31/2024, 12/31/2025 and 12/31/2026
Answer to 52 Pa. Code 53.52 c[2]

Line	Account Title	Per Books 12/31/2024	Pro Forma 12/31/2025	Pro Forma 12/31/2026
30	**Liabilities and Other Credits**			
31				
32	Proprietary Capital:			
33	Preferred stock	$125,800	$125,800	$125,800
34	Common stock Issued	240,146	240,146	240,146
35	Retained earnings	5,050,799	5,431,167	5,596,692
36	Treasury stock, at cost	(159,250)	(159,250)	(159,250)
37	*Total proprietary capital*	5,257,495	5,637,863	5,803,388
38				
39	Long-Term Debt:			
40	Long term debt	18,477,675	17,612,601	16,710,309
41	Capitalized Lease Obligations	349,544	220,330	105,672
42	*Total long-term debt*	18,827,219	17,832,931	16,815,981
43				
44	Current and Accrued Liabilities:			
45	Line of Credit	$700,000	$1,021,224	$1,618,335
46	Current maturities of long-term debt	865,074	902,292	941,209
47	Current maturities of capitalized leases	129,214	114,658	70,731
48	Accounts payable- Trade	520,911	520,911	520,911
49	Accounts payable- Related party	133,216	133,216	133,216
50	Due for Purchased electricity	537,362	537,362	537,362
51	Accrued expenses	227,799	227,799	227,799
52	Customer deposits	195,713	195,713	195,713
53	Derivative investment		0	0
54	Overcollected power costs		0	0
55	*Total current and accrued liabilities*	3,309,289	3,653,175	4,245,276
56				
57	Deferred Credits and Other Liabilities:			
58	Deferred income taxes	1,172,700	1,172,700	1,172,700
59	Accrued postretirement cost	185,579	185,579	185,579
60	Regulatory Liability	230,379	230,379	230,379
61	*Total deferred credits*	1,588,658	1,588,658	1,588,658
62				
63	**Total Liabilities and Other Credits**	**$28,982,661**	**$28,712,627**	**$28,453,303**

C3 (R)

Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026 (R)

Original Cost of Utility Plant in Service
12/31/2024, 12/31/2025 and 12/31/2026
Answer to 52 Pa. Code 53.52 c[3]

			Original Cost			Original Cost			Original Cost			
			Balance 12/31/2023	HY 2024		Balance 12/31/2024	FTY 2025		Balance 12/31/2025	FPFTY 2026		Balance 12/31/2026
Line	Acct No.	Account Title	Pro Forma	Additions	Retirements	Pro Forma	Additions	Retirements	Pro Forma	Additions	Retirements	Pro Forma
1	*Distribution Plant.*											
2	360	Land & Land Rights	178,334			178,334			178,334			178,334
3	361	Structures and improvements				0			0			0
4	362	Station Equipment	3,654,978	13,265		3,668,243			3,668,243			3,668,243
5	362.01	Station Equipment- Fully depr.	324,557			324,557			324,557			324,557
6	364	Poles, Tower & Fixtures	12,456,164	1,918,214	(917,791)	13,456,587	734,500		14,191,087	742,085		14,933,172
7	365	Overhead Conductors & Devices	5,529,274	1,721,121	(1,166,423)	6,083,972	362,500		6,446,472	358,475		6,804,947
8	366	Underground Conduit	26,899			26,899			26,899			26,899
9	367	Underground Conductors & Devices	1,008,032	19,299	(15,781)	1,011,550			1,011,550			1,011,550
10	368	Line Transformers	2,923,411	285,923	(11,002)	3,198,332	58,500		3,256,832	108,755		3,365,587
11	369	Services	849,838	12,862	(7,390)	855,310	101,000		956,310	104,030		1,060,340
12	369.1	Underground Services	1,300,817	76,122	(32,390)	1,344,549	40,000		1,384,549	41,200		1,425,749
13	370	Meters	986,943	27,460	(2,922)	1,011,481	20,000		1,031,481	10,000		1,041,481
14	371	Installations on Customers' premises	373,328	4,992	(8,702)	369,618	150,000		519,618	0		519,618
15	373	Street Lighting & Signal Systems	118,915	419	(62)	119,272	3,000		122,272	3,000		125,272
16	Total Distribution Plant		29,731,490	4,079,677	(2,162,464)	31,648,703	1,469,500	0	33,118,203	1,367,545	0	34,485,748
17												
18	*General Plant*											
19	390.1	Structures & Improvements, office	2,486,413	3,722,470	(544,972)	5,663,911			5,663,911			5,663,911
20	390.2	Structures & Improvements, other	884,002			884,002			884,002			884,002
21	391	Office Furniture & Equipment	601,624	297,517	(124,652)	774,489			774,489			774,489
22	391.1	Office Furn & Equip- Fully depr.				0			0			0
23	392	Transportation Equipment	1,646,618	66,390	(180,998)	1,532,010	250,000		1,782,010	455,000		2,237,010
24	394	Tools, Shop & Garage Equipment	90,042			90,042	10,000		100,042	12,875		112,917
25	395	Laboratory Equipment	96,079		(80,650)	15,429			15,429			15,429
26	396	Power Operated Equipment	98,149	72,184	(80,519)	89,814			89,814			89,814
27	397	Communication Equipment	110,323	7,578		117,901			117,901			117,901
28	398	Miscellaneous Equipment				0			0			0
29		Intangible plant, organization	1,046			1,046			1,046			1,046
30	301	Intangible plant, EDI	284,588			284,588			284,588			284,588
31		Total General Plant	6,298,884	4,166,139	(1,011,791)	9,453,232	260,000	0	9,713,232	467,875	0	10,181,107
32												
33		Total Plant in Service	36,030,374	8,245,816	(3,174,254)	41,101,936	1,729,500	0	42,831,436	1,835,420	0	44,666,856

C3 (R)

Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026 (R)

Original Cost of Utility Plant in Service
12/31/2024, 12/31/2025 and 12/31/2026
Answer to 52 Pa. Code 53.52 c[3]

				Accumulated Depreciation			Accumulated Depreciation		Accumulated Depreciation			Net Book Valu
				Balance	HY 2024		Balance	FTY 2025	Balance	FPFTY 2026	Balance	12/31/2026
Line	Acct No.	Account Title	Depr. Rate	12/31/2023 Balance	Additions	Retirements	12/31/2024 Balance	Additions	12/31/2025 Balance	Additions	12/31/2026 Balance	Balance
1	*Distribution Plant.*											
2	360	Land & Land Rights		0	0	0	0	0	0	0	0	178,334
3	361	Structures and improvements	4.08%				-		-		-	0
4	362	Station Equipment	6.88%	2,921,442	141,847	-	3,063,289	252,375	3,315,664	252,375	3,568,039	100,204
5	362.01	Station Equipment- Fully depr.		324,557			324,557	-	324,557	-	324,557	0
6	364	Poles, Tower & Fixtures	3.50%	3,885,628	440,594	(216,988)	4,109,234	483,834	4,593,068	509,675	5,102,743	9,830,429
7	365	Overhead Conductors & Devices	3.97%	1,707,606	221,459	(117,991)	1,811,074	248,729	2,059,803	263,041	2,322,844	4,482,103
8	366	Underground Conduit	3.15%	10,761	849		11,610	847	12,457	847	13,305	13,594
9	367	Underground Conductors & Devices	4.36%	634,193	43,964		678,157	44,104	722,261	44,104	766,364	245,186
10	368	Line Transformers	3.52%	1,388,859	102,104	(23,844)	1,467,119	113,611	1,580,730	116,555	1,697,284	1,668,303
11	369	Services	6.00%	788,699	9,466	(5,385)	792,780	54,349	847,129	60,499	907,628	152,712
12	369.1	Underground Services	2.48%	464,366	32,826	(1,188)	496,004	33,841	529,845	34,848	564,693	861,057
13	370	Meters	7.70%	556,160	75,858	(2,922)	629,096	78,654	707,750	79,809	787,559	253,922
14	371	Installations on Customers' premises	10.37%	(9,128)	38,453	(13,588)	15,737	46,107	61,844	53,884	115,728	403,889
15	373	Street Lighting & Signal Systems	2.40%	(71,623)	2,861	(149)	(68,911)	2,899	(66,012)	2,971	(63,042)	188,314
16	Total Distribution Plant			12,601,520	1,110,281	(382,055)	13,329,746	1,359,349	14,689,095	1,418,607	16,107,702	18,378,046
17												
18	*General Plant*											
19	390.1	Structures & Improvements, office	4.58%	507,553	92,336	(485,119)	114,770	259,407	374,177	259,407	633,584	5,030,327
20	390.2	Structures & Improvements, other	5.20%	31,957	45,708		77,665	45,968	123,633	45,968	169,601	714,401
21	391	Office Furniture & Equipment	19.49%	378,038	69,221	(122,201)	325,058	150,948	476,006	150,948	626,954	147,535
22	391.1	Office Furn & Equip- Fully depr.					0	0	0	0	0	0
23	392	Transportation Equipment	10.00%	1,035,960	155,341	(180,998)	1,010,303	165,701	1,176,004	200,951	1,376,955	860,055
24	394	Tools, Shop & Garage Equipment	6.17%	29,100	4,976		34,076	5,864	39,940	6,570	46,510	66,407
25	395	Laboratory Equipment	2.66%	90,397	1,544	(80,650)	11,291	410	11,701	410	12,112	3,318
26	396	Power Operated Equipment	3.11%	59,514	2,845	(61,308)	1,051	2,793	3,844	2,793	6,637	83,176
27	397	Communication Equipment	7.71%	29,968	8,336		38,304	9,090	47,394	9,090	56,484	61,417
28	398	Miscellaneous Equipment	0.00%	(64)			(64)	0	(64)	0	(64)	64
29		Intangible plant, organization	0.00%	0			0	0	0	0	0	1,046
30	301	Intangible plant, EDI	14.28%	284,586			284,586	2	284,588	0	284,588	0
31		Total General Plant		2,447,009	380,307	(930,276)	1,897,040	640,184	2,537,224	676,138	3,213,362	6,967,746
32												
33		Total Plant in Service		15,048,529	1,490,588	(1,312,331)	15,226,786	1,999,533	17,226,319	2,094,745	19,321,064	25,345,792

C4 (R)

Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026 (R)

Reserve for Depreciation of Utility Plant
12/31/2024, 12/31/2025 and 12/31/2026
Answer to 52 Pa. Code 53.52 c[4]

	Account Title	Per Books 12/31/2024	Pro Forma 12/31/2025	Pro Forma 12/31/2026
1	Reserve for Depreciation	$15,226,786	$17,226,319	$19,321,064

C5 (R)

Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026 (R)

Operating Income Setting Forth the Operating Revenues and Expenses at Present Rates
HY 2024, FTY 2025 and FPFTY 2026
Answer to 52 Pa. Code 53.52 c[5]

	Account Title	Year Ended 12/31/2024 [Per Books]	Year Ended 12/31/2024 Distribution Only	Year Ended 12/31/2025 Distribution Only	Year Ended 12/31/2026 Distribution Only
1	Operating revenue	$13,158,392	$6,255,065	$6,683,214	$6,696,602
2					
3	Operating revenue deductions:				
4	Operating expenses	9,252,068	3,531,630	4,084,441	4,292,779
5	Depreciation expense	1,335,247	1,335,247	1,844,192	1,939,404
6	Taxes other than income tax	814,557	394,406	419,544	419,926
7	Rate case expense amortization	0	0	0	0
8	Total Operating revenue deductions	11,401,872	5,261,283	6,348,178	6,652,109
9					
10	Net operating income before income taxes	1,756,519	993,782	335,036	44,493
11					
12	Income tax expense	176,086	(35,246)	(45,332)	(121,031)
13					
14	Net utility operating income	$1,580,433	$1,029,028	$380,368	$165,524

C5-1 (R)

Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026 (R)

Comparison to Prior Rate Case
Prior Rate Case and FPFTY 2026

Line	Description	FPFTY 2026	R-2019-3008208, Order	Difference	Gross-Up for GRT	Revenue Requirement
1	Revenue	6,696,602	5,348,459	1,348,143	1.0000	(1,348,143)
2						
3	*kWh*	*105,165,077*	*106,065,175*			
4						
5	O&M	4,292,779	2,513,845	1,778,934	1.0627	1,890,471
6	Taxes other than income, Rate Case	419,926	414,415	5,511	1.0627	5,857
7	Depreciation	1,939,404	1,162,329	777,075	1.0627	825,797
8	Income tax	(121,031)	268,113			
9	Net Income	165,524	989,758			
10						
11	Rate Base	$25,974,028	$13,819,457	12,154,571		
12	Required Return	8.18%	7.16%			
13	Target Return	2,124,675	989,758	1,134,918	1.0627	1,206,076
14						
15	Income Tax Expense	599,739	268,113	331,626	1.0627	352,418
16						
17	Rounding					(83,674)
18	Revenue Increase Required					2,848,804
19						
20						

D (R)

Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026 (R)
Summary of Allocator Values

Line	Units	Allocator Names	Total	Sch. 1- RS	Sch. 2- RSAE	Sch. 3- NRS	Sch. 3- NRH	Sch. 4- CS	Sch. 4- CSH	Sch. 5- IS	Sch. 6- MSL	Sch. 7- POL	Sch. 8- EU
		Class Allocators											
1	**InputAlloc**	**ALLOCATION VALUES**											
2	MWh	MWh-Meter	105,165,077	44,639,052	394,372	4,657,346	6,256	28,611,970	7,216	26,746,293	0	0	102,572
3	MW	NCP-Prim	20,036	9,206	123	846	9	5,356	18	4,411	13	41	12
4	MW	NCP-Sec	15,613	9,206	123	846	9	5,356	18	0	13	41	0
5	MW	NCP-Ltr	3,705	0	0	0	4	3,632	14	0	13	41	0
6	#	AVG-CUST	6,497	5,139	29	923	1	386	1	14	0	0	4
7	$	Services_Cost	5,310,086	3,937,424	22,155	707,421	766	618,293	1,602	22,425	0	0	0
8	#	Meters	6,497	5,139	29	923	1	386	1	14	0	0	4
9	$	Meter_Cost	3,076,038	1,850,100	10,410	332,400	360	666,410	1,726	166,936	0	0	47,696
10	$	Dist_Rev	6,369,121	3,357,674	24,383	490,753	676	1,510,082	1,028	880,700	13,496	81,371	8,957
11	$	Total_Rev	13,039,628	6,968,890	53,191	826,557	1,630	3,210,823	1,585	1,858,613	19,106	81,371	17,863
12	$	Supp_Rev	6,670,507	3,611,216	28,807	335,804	954	1,700,741	557	977,913	5,609	0	8,907
13	$	CustDeposits	12120000.0%	6988666.7%	51333.3%	680236.8%	1812.2%	2739398.7%	1355.1%	1569374.2%	0.0%	72060.7%	15762.3%
14	$	Write-Offs	100.0%	87.0%	0.6%	1.7%	0.0%	6.7%	0.0%	3.8%	0.0%	0.2%	0.0%
15	#	StLgt-Lamps	2								1	1	
16													

Line							
17	**InputFunc**	**FUNCTIONAL ALLOCATORS**	**Total**	**Supply**	**Transmission**	**Primary Dist**	**Secondary Dist**
18		OH_Cond	100.00%			83.37%	16.63%
19		UG_Cond	100.00%			57.35%	42.65%
20		Trans	100.00%			0.00%	100.00%
21							

Line						
22						
23	**InputClass**	**CLASSIFICATIONS**	**Total**	**Demand**	**Commodity**	**Customer**
24		PTF-Sec-Z	100.00%	36.96%		63.04%
25		OH-Sec-Z	100.00%	43.97%		56.03%
26		UG-Sec-Z	100.00%	63.71%		36.29%
27		Trans-Min	100.00%	22.45%		77.55%
28						

D1 (R)

Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026 (R)
Distribution System Functionalizaton and Classification

		Primary / Secondary Split for OH ad UG Conductors		
Line	**Conductor type**	**Circuit Miles**	**Line Miles (Circuit**	**Description**
1	OH Primary (1 Ph)	304.82	609.64	1 phase wire, 1 neutral wire
2	OH Primary (2 Ph)	6.99	20.97	2 phase wires, 1 neutral wire
3	OH Primary (3 Ph)	72.84	291.36	3 phase wires, 1 neutral wire
4	OH Secondary	111.47	111.47	1 triplexed conductor
5	UG Primary (1 Ph)	32.28	32.28	1 cable with concentric neutral
6	UG Primary (2 Ph)	0.49	0.98	2 cable with concentric neutral
7	UG Primary (3 Ph)	6.86	20.58	3 cable with concentric neutral
8	UG Secondary	34.29	34.29	1 duplexed or triplexed conduct
9		570.04	1121.57	
11	**Totals**			
12	OH Primary	384.65	921.97	
13	OH Secondary	111.47	111.47	
14		496.12	1033.44	
15				
16	UG Primary	39.63	53.84	
17	UG Secondary	34.29	34.29	
18		73.92	88.13	
19				
20	**Totals**			**Average**
21	OH Primary	77.53%	89.21%	83.37%
22	OH Secondary	22.47%	10.79%	16.63%
23		100.00%	100.00%	100.00%
24				
25	UG Primary	53.61%	61.09%	57.35%
26	UG Secondary	46.39%	38.91%	42.65%
27		100.00%	100.00%	100.00%
28				

D1 (R)

Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026 (R)
Distribution System Functionalizaton and Classification

		Zero-Load Components for Secondary		
		Poles	**Overhead Conductors**	**Underground Conductors**
	Labor	37.2%	31.7%	8.9%
	Overhead	14.4%	10.5%	4.5%
	Vehicle	13.3%	8.8%	2.8%
	Zero-Load Component	**64.9%**	**51.0%**	**16.2%**
	Material	35.1%	49.0%	83.8%
	Total Cost	100.0%	100.0%	100.0%
	Overheads are spread over labor hours.			
	Zero-Load Component	64.9%	51.0%	16.2%
	Prior Study	61.2%	61.1%	56.4%
	Average	**63.0%**	**56.0%**	**36.3%**

		Poles	**Overhead Conductors**	**Underground Conductors**
	Labor	414,674	191,263	313
	Overhead	160,680	63,525	159
	Transportation	148,166	53,303	99
	Materials	392,078	296,158	2,947
		1,115,598	604,249	3,518
		Account 364	Account 365	Account 367

D2 (R)

Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026 (R)
NCP- Sum of Customers' Usage

COMPUTED CLASS DEMANDS (NCPs)

Line	Description	Sch. 1- RS	Sch. 2- RSAE	Sch. 3- NRS	Sch. 3- NRH	Sch. 4- CS	Sch. 4- CSH	Sch. 5- IS	Sch. 6- MSL	Sch. 7- POL	Sch. 8- EU	Total
1	Total Number of Customers	5,139	29	923	1	386	1	14			4	6,497
2	Average Peak per Customer	-	-	-	-	-	-	-			-	
3												
4												
5												
6	**NCP- Primary**	9,206	123	846	9	5,356	18	4,411	13	41	12	20,036
7	Class peaks											-
8	**Shares of Total**	45.95%	0.61%	4.22%	0.04%	26.73%	0.09%	22.01%	0.07%	0.21%	0.06%	100.00%
9												
10												
11	1CP	8,446	58	782	-	5,203	-	4,179	-	-	-	18,668
12	Share of 1CP	45.25%	0.31%	4.19%	0.00%	27.87%	0.00%	22.39%	0.00%	0.00%	0.00%	100.00%
13												
14	**NCP- Secondary**	9,206	123	846	9	5,356	18		13	41		15,613
15	Class peaks	-	-	-	-	-	-		-	-		-
16	**Shares of Total**	58.96%	0.79%	5.42%	0.06%	34.31%	0.12%	0.00%	0.09%	0.27%	0.00%	100.00%
17												
18	**NCP-LTr**											
19	Secondary Class peaks	9,206	123	846	9	5,356	18		13	41		15,613
20	Capacity of Minimum system	22,957	129	4,125	4	1,724	4	63	-	-	18	29,024
21	Class peaks less Capacity of minimum system	-	-	-	4	3,632	14	-	13	41	-	3,705
22	**Shares of Total**	0.00%	0.00%	0.00%	0.12%	98.03%	0.37%	0.00%	0.36%	1.12%	0.00%	100.00%
23												
24	Total number of transformers on system											3,628
25	Transfomer capacity- kVa											10
26	Assumed power factor											80%
27	Total Capacity of Transformer minimum system											29,024
28	Number of customers	5,139	29	923	1	386	1	14			4	6,497
29	Capacity per Customer of Transformer minimum system- kW											4.47
30												

D3 (R)

Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026 (R)
Transformers Classification

Transformers Minimum Size Component

Line	Minimum Size	Minimum Size	Cost for Minimum Size	Total Cost Minimum Size	Number	Replacement Cost	Minimum Size Component
1	TPM10 CSP	10 kVA	1,331	4,828,578	3,628	5,975,094	80.8%
2	Prior Study						74.3%
3	Minimum Size Component						**77.5%**
4							

Transformers Unit Costs

Line	Description	Description		Cost	Install	Total	Quantity	Total Cost
7	**Line Transformers**							
8	TPM1.5	1.5 - KVA		$950	$281	$1,231	8	9,847
9	TPM5	5 - KVA		$995	$281	$1,276	171	218,182
10	TPM7.5	7.5 - KVA		$995	$281	$1,276	14	17,863
11	TPM10 CSP	10 - KVA	3/2024	$1,050	$281	$1,331	1,075	1,430,739
12	TPM15 CSP	15- KVA	3/2024	$1,695	$281	$1,976	1,248	2,465,948
13	TPM25 CSP	25- KVA	10/2022	$1,935	$281	$2,216	429	950,630
14	TPM37.5 Conv	37.5- KVA	10/2022	$2,715	$281	$2,996	120	359,510
15	TPM50 Conv	50- KVA		$1,575	$281	$1,856	51	94,652
16	TPM75 Conv	75- KVA		$2,050	$281	$2,331	29	67,597
17	TPM100 Conv	100- KVA	3/2024	$3,910	$281	$4,191	30	125,728
18	TPM167 Conv	167 - KVA pole Mount		$3,675	$281	$3,956	2	7,912
19	TPM250 Conv	250 - KVA pole Mount		$4,695	$281	$4,976		-
20	TPM333 Conv	333 - KVA pole Mount		$5,750	$281	$6,031		-
21	TPM333 Conv (3 ph)	333 - KVA pole Mount		$5,750	$281	$6,031	2	12,062
22								
23	**Pad-Mounted Transformers- 1-Phase**							
24	TPD10			$1,415	$1,415	$478	8	3,820
25	TPD15		Aug-24	$1,485	$3,795	$478	99	47,278
26	TPD25		Oct-22	$1,625	$5,415	$478	198	94,557
27	TPD37			$1,795	$1,795	$478	20	9,551
28	TPD50		Aug-23	$2,125	$2,807	$478	67	31,997
29	TPD75			$2,495	$2,495	$478	11	5,253
30	TPD167			$4,250	$22,550	$478	1	478
31								
32	**Pad-Mounted Transformers- 3 Phase**							
33	TPD45			$5,925	$5,925	$478	4	1,910
34	TPD112.5		Jun-24	$6,495	$19,985	$478	9	4,298
35	TPD150			$7,150	$7,150	$478	17	8,119
36	TPD225			$7,995	$7,995	$478	5	2,388
37	TPD300	12/1/2023 quote		$9,175	$29,100	$478	6	2,865
38	TPD500		Feb-24	$12,100	$34,045	$478	1	478
39	TPD1000			$18,985	$18,985	$478	1	478
40	TPD1500		Feb-23	$25,625	$58,735	$478	2	955
							3,628	5,975,094

D4 (R)

Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026 (R)
Service Costs

	Rate Class	Replacement Cost	Customers	Services Cost
1	Sch. 1- RS	$766	5,139	3,937,424
2	Sch. 2- RSAE	$766	29	22,155
3	Sch. 3- NRS	$766	923	707,421
4	Sch. 3- NRH	$766	1	766
5	Sch. 4- CS	$1,602	386	618,293
6	Sch. 4- CSH	$1,602	1	1,602
7	Sch. 5- IS	$1,602	14	22,425
8	Sch. 6- MSL			0
9	Sch. 7- POL			0
10	Sch. 8- EU		4	0
11	**Total Service Cost**		**6,497**	**5,310,086**
12				
13	Sch. 1- RS			
14	Residential Overhead	$514	75%	385
15	Residential Underground	$1,523	25%	381
16		$766	100%	766
17	Sch. 4- CS			
18	Large Commercial Overhead	$1,399	85%	1,189
19	Large Commercial Underground	$2,752	15%	413
20		$1,602	100%	1,602

D5 (R)

Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026 (R)
Meter Costs

		Customers	Material	Installation	Other Equipment (with Installation)	Total Cost Per Meter	Total Meter Cost	
1	Sch. 1- RS	5,139	$305	$55		$360	1,850,100	60.15%
2	Sch. 2- RSAE	29	$305	$55		$360	10,410	0.34%
3	Sch. 3- NRS	923	$305	$55		$360	332,400	10.81%
4	Sch. 3- NRH	1	$305	$55		$360	360	0.01%
5	Sch. 4- CS	386	$875	$55	$796	$1,726	666,410	21.66%
6	Sch. 4- CSH	1	$875	$55	$796	$1,726	1,726	0.06%
7	Sch. 5- IS	14	$11,924			$11,924	166,936	5.43%
8	Sch. 6- MSL	0					0	0.00%
9	Sch. 7- POL	0					0	0.00%
10	Sch. 8- EU	4	$11,924			$11,924	47,696	1.55%
11		6,497					3,076,038	100.00%
12								
13	(A) Includes Meter, as well as CT, PT and other equipment if applicable							
14								

D6 (R)

Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026 (R)
Customer Deposits and Advances; Uncollectible Accounts

		Revenue	% Residential	% Commercial	Write-Offs	Write-Offs	Deposits
1	Sch. 1- RS	6,779,723	99.3%		17,460	87.0%	69,887
2	Sch. 2- RSAE	49,799	0.7%		128	0.6%	513
3	Sch. 3- NRS	770,904		13.4%	332	1.7%	6,802
4	Sch. 3- NRH	2,054		0.0%	1	0.0%	18
5	Sch. 4- CS	3,104,525		53.9%	1,339	6.7%	27,394
6	Sch. 4- CSH	1,536		0.0%	1	0.0%	14
7	Sch. 5- IS	1,778,551		30.9%	767	3.8%	15,694
8	Sch. 6- MSL	19,185				0.0%	
9	Sch. 7- POL	81,665		1.4%	35	0.2%	721
10	Sch. 8- EU	17,863		0.3%	8	0.0%	158
11		12,605,805	100.0%	100.0%	20,071	100.0%	121,200
12				5,757,098			

Year	Residential	Commercial
2024	10,249	7
2023	18,174	4,210
2022	17,712	81
2021	38,989	1,172
2020	10,297	13,964
2019	9,451	11
2018	34,023	1,359
2017	11,098	1,028
2016	8,299	516
	158,291	22,347
Average	17,588	2,483

	Residential	Commercial	Total
2024 Deposits	70,400	50,800	121,200
Customers	322	72	394

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Wellsboro Electric Company
Embedded Cost of Service Study (ECOSS) (R)
FPFTY Ending December 31, 2026
Index to Class Cost of Service Study

Line	SCHEDULE	DESCRIPTION
1	E (R)	Index to Class Cost of Service Study
2	E-1 (R)	Summary of Results
3	E-1A (R)	Class Allocations- Total
4	E-1B (R)	Revenue Requirement By Functional Classification
5	E-1C (R)	Customer-Related Costs In Revenue Requirement
6	E-2 (R)	Funtionalization
7	E-3 (R)	Classification
8	E-4A (R)	Class Allocation- Primary Demand
9	E-4B (R)	Class Allocation- Secondary Demand
10	E-4C (R)	Class Allocation- Secondary Customer
11	E-4D (R)	Class Allocation- Billing Customer
12	E-5A (R)	Allocator Assignments
13	E-5B (R)	Functionalization Factors
14	E-5C (R)	Classification Factors
15	E-5D (R)	Class Allocation Factors

Sum
Summary of Results
Tot
E-1 (R)

Wellsboro Electric Company
Embedded Cost of Service Study (ECOSS) (R)
FPFTY Ending December 31, 2026
Summary of Results

Line	Account	No.	Balance	RS	RSAE	NRS	NRH	CS	CSH	IS	MSL	POL	EX
1	Distribution Revenue		6,369,121	3,357,674	24,383	490,753	676	1,510,082	1,028	880,700	13,496	81,371	8,957
2	Forfeited Discounts		30,962	26,934	198	513	1	2,066	1	1,183	0	54	12
3	Other Revenue		296,518	149,539	1,751	16,388	116	73,888	235	53,385	216	809	191
4	**Total Revenue**		6,696,602	3,534,147	26,332	507,654	794	1,586,036	1,264	935,269	13,713	82,234	9,159
5													
6	Expenses		6,531,077	3,874,542	34,945	541,846	2,050	1,281,314	3,966	760,906	7,454	16,771	7,285
7	Net income		165,524	(340,395)	(8,613)	(34,191)	(1,256)	304,723	(2,702)	174,363	6,259	65,463	1,874
8													
9	Rate Base		25,974,028	14,389,602	144,196	1,873,193	9,464	5,741,037	19,230	3,524,195	111,670	138,695	22,745
10													
11	Return on Rate Base		0.64%	(2.37%)	(5.97%)	(1.83%)	(13.27%)	5.31%	(14.05%)	4.95%	5.60%	47.20%	8.24%
12	*Relative*		*1.00 x*	*(3.71) x*	*(9.37) x*	*(2.86) x*	*(20.82) x*	*8.33 x*	*(22.05) x*	*7.76 x*	*8.80 x*	*74.07 x*	*12.93 x*
13	Revenue Requirement		9,545,405	5,570,864	52,272	761,961	3,231	1,932,275	6,378	1,160,983	19,409	28,173	9,859
14	*% Total*		*100.0%*	*58.4%*	*0.5%*	*8.0%*	*0.0%*	*20.2%*	*0.1%*	*12.2%*	*0.2%*	*0.3%*	*0.1%*
15	Operating expenses		4,119,386	2,533,909	22,291	364,270	1,291	744,956	2,427	436,051	3,428	6,637	4,126
16	Depreciation expense		1,939,404	1,082,693	10,661	142,769	690	429,324	1,421	261,834	2,726	4,718	2,567
17	Regulatory Commission Expenses		153,393	84,504	850	10,945	56	34,774	116	21,193	315	482	157
18	General taxes / Other		44,148	24,321	245	3,150	16	10,008	33	6,100	91	139	45
19	Uncollectibles expense		20,000	17,398	128	331	1	1,334	1	764	0	35	8
20	GRT		543,858	318,269	2,969	43,959	184	109,523	362	65,278	1,132	1,611	570
21			6,820,188	4,061,095	37,143	565,424	2,238	1,329,920	4,361	791,221	7,693	13,621	7,472
22	Pre-tax income		2,725,217	1,509,769	15,129	196,537	993	602,355	2,018	369,762	11,717	14,552	2,386
23	Income taxes		600,542	332,700	3,334	43,310	219	132,738	445	81,482	2,582	3,207	526
24	Net income		2,124,675	1,177,069	11,795	153,227	774	469,617	1,573	288,279	9,135	11,345	1,861
25													
26	Return on Rate Base		8.18%	8.18%	8.18%	8.18%	8.18%	8.18%	8.18%	8.18%	8.18%	8.18%	8.18%
27													
28	Revenue Increase Required		2,848,804	2,036,717	25,940	254,307	2,437	346,238	5,114	225,714	5,696	(54,060)	700
29	Revenue Increase %		44.73%	60.66%	106.38%	51.82%	360.26%	22.93%	497.51%	25.63%	42.21%	(66.44%)	7.81%

Total
Class Allocations- Total
Tot
E-1A (I

Wellsboro Electric Company
Embedded Cost of Service Study (ECOSS) (R)
FPFTY Ending December 31, 2026
Class Allocations- Total

Line	Account	No.	Balance		RS	RSAE	NRS	NRH	CS	CSH	IS	MSL	POL	EX
1	**I. ELECTRIC PLANT IN SERVICE**													
2	INTANGIBLE PLANT													
3	EDI Software	303	284,588	.	225,096	1,267	40,442	44	16,907	44	613	0	0	175
4	Total INTANGIBLE Plant		284,588	.	225,096	1,267	40,442	44	16,907	44	613	0	0	175
5														
6	**C. TRANSMISSION PLANT**													
7	Transmission Plant	361	0	.	0	0	0	0	0	0	0	0	0	0
8	Total TRANSMISSION Plant	350-359	0	.	0	0	0	0	0	0	0	0	0	0
9														
10	**D. DISTRIBUTION PLANT**													
11	Land & Land Rights	360	178,334	.	81,941	1,096	7,527	78	47,673	162	39,258	120	369	110
12	Structures and improvements	361	0	.	0	0	0	0	0	0	0	0	0	0
13	Station Equipment	362	3,992,800	.	1,834,608	24,545	168,528	1,753	1,067,372	3,629	878,966	2,682	8,255	2,462
14	Poles, Tower & Fixtures	364	14,933,172	.	7,502,460	90,755	798,123	6,225	3,736,252	12,629	2,740,757	9,153	28,174	8,643
15	OH Conductors & Devices	365	6,804,947	.	3,402,729	41,628	356,704	2,869	1,725,059	5,835	1,248,945	4,239	13,049	3,890
16	UG Conduits and Conductors	366	1,038,449	.	567,425	6,604	63,311	445	265,573	895	131,107	643	1,980	466
17	Line Transformers	368	3,365,587	.	2,068,828	11,641	371,698	1,286	896,126	3,206	0	2,745	8,448	1,610
18	Services	369	2,486,089	.	1,843,433	10,372	331,202	359	289,474	750	10,499	0	0	0
19	Meters	370	1,041,481	.	626,404	3,525	112,544	122	225,632	585	56,521	0	0	16,149
20	Install. Customers' premises	371	519,618	.	410,994	2,313	73,842	80	30,870	80	1,120	0	0	320
21	Street Lighting & Signal	373	125,272	.	0	0	0	0	0	0	0	62,636	62,636	0
22	Total DISTRIBUTION Plant	360-373	34,485,748	.	18,338,822	192,479	2,283,478	13,216	8,284,030	27,771	5,107,173	82,218	122,912	33,650
23														
24	**E. GENERAL PLANT**													
25	General Plant	389	9,778,618	.	6,038,641	52,695	872,933	3,022	1,756,233	5,697	1,012,637	8,866	16,266	11,629
26	Communication Equip	398	117,901	.	72,808	635	10,525	36	21,175	69	12,209	107	196	140
27	Total GENERAL Plant	389-399	9,896,519	.	6,111,449	53,330	883,458	3,059	1,777,407	5,766	1,024,846	8,973	16,462	11,769
28														
29	**TOTAL UTILITY PLANT**		44,666,856	.	24,675,367	247,076	3,207,378	16,319	10,078,344	33,581	6,132,632	91,191	139,374	45,595
30														

Total
Class Allocations- Total
Tot
E-1A (F

Wellsboro Electric Company
Embedded Cost of Service Study (ECOSS) (R)
FPFTY Ending December 31, 2026
Class Allocations- Total

Line	Account	No.	Balance		RS	RSAE	NRS	NRH	CS	CSH	IS	MSL	POL	EX
31	**II. DEPRECIATION RESERVE**													
32	Intangible Plant		284,588	.	225,096	1,267	40,442	44	16,907	44	613	0	0	175
33	Transmission Plant		0	.	0	0	0	0	0	0	0	0	0	0
34	Structures and improvements		0	.	0	0	0	0	0	0	0	0	0	0
35	Station Equipment		3,892,596	.	1,788,566	23,929	164,299	1,709	1,040,585	3,538	856,908	2,614	8,048	2,400
36	Poles, Towers and Fixtures		5,102,743	.	2,563,630	31,012	272,723	2,127	1,276,697	4,315	936,531	3,128	9,627	2,953
37	OH Conductors and Devices		2,322,844	.	1,161,509	14,210	121,760	979	588,843	1,992	426,323	1,447	4,454	1,328
38	UG Conduits and Conductors		779,669	.	426,023	4,958	47,534	334	199,392	672	98,436	483	1,486	350
39	Line Transformers		1,697,284	.	1,043,322	5,870	187,449	648	451,921	1,617	0	1,384	4,261	812
40	Services		1,472,321	.	1,091,724	6,143	196,146	212	171,433	444	6,218	0	0	0
41	Meters		787,559	.	473,682	2,665	85,104	92	170,621	442	42,741	0	0	12,212
42	Install. Customers' premises		115,728	.	91,536	515	16,446	18	6,875	18	249	0	0	71
43	Street Lighting & Signal		(63,042)	.	0	0	0	0	0	0	0	(31,521)	(31,521)	0
44	General Plant		2,928,774	.	1,808,621	15,783	261,450	905	526,006	1,706	303,293	2,655	4,872	3,483
45	Total DEPRECIATION RESE	108	19,321,064	.	10,673,709	106,351	1,393,353	7,069	4,449,280	14,788	2,671,311	(19,809)	1,227	23,785
46														
47	**III. OTHER RATE BASE ITEMS**													
48	Cash Working Capital	131	512,714	.	314,869	2,779	44,868	161	93,184	304	54,657	488	895	510
49	CWIP	131	0	.	0	0	0	0	0	0	0	0	0	0
50	Materials & Supplies	255	302,296	.	180,923	1,566	26,301	94	59,730	193	32,011	287	536	655
51	Customer Deposits		(120,033)	.	(69,214)	(508)	(6,737)	(18)	(27,130)	(13)	(15,543)	0	(714)	(156)
52	ADIT	154	(38,728)	.	(21,335)	(214)	(2,763)	(14)	(8,780)	(29)	(5,351)	(80)	(122)	(40)
53	Accrued Pension / OPEB	182	(28,013)	.	(17,299)	(151)	(2,501)	(9)	(5,031)	(16)	(2,901)	(25)	(47)	(33)
54	Total OTHER RATE BASE	131-283	628,236	.	387,944	3,471	59,168	214	111,973	438	62,874	670	548	935
55														
56	**TOTAL RATE BASE**		25,974,028	.	14,389,602	144,196	1,873,193	9,464	5,741,037	19,230	3,524,195	111,670	138,695	22,745
57														

Total
Class Allocations- Total
Tot
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Wellsboro Electric Company
Embedded Cost of Service Study (ECOSS) (R)
FPFTY Ending December 31, 2026
Class Allocations- Total

Line	Account	No.	Balance		RS	RSAE	NRS	NRH	CS	CSH	IS	MSL	POL	EX
58	**I. OPERATING AND MAINTENANCE EXPENSES**													
59	**B. TRANSMISSION EXPENSE**													
60	Transmission Expense		0	.	0	0	0	0	0	0	0	0	0	0
61	Total TRANSMISSION Expe		0		0	0	0	0	0	0	0	0	0	0
62														
63	**C. DISTRIBUTION EXPENSE**													
64	Ops Supv & Engineering	580	0	.	0	0	0	0	0	0	0	0	0	0
65	Station Expenses	582	0	.	0	0	0	0	0	0	0	0	0	0
66	OH Line Expenses	583	6,020	.	3,010	37	316	3	1,526	5	1,105	4	12	3
67	Street Lighting Expenses	585	267	.	0	0	0	0	0	0	0	134	134	0
68	Meter Expenses	586	39,903	.	24,000	135	4,312	5	8,645	22	2,166	0	0	619
69	Customer Install. expense	587	267	.	212	1	38	0	16	0	1	0	0	0
70	Misc. Distribution Expenses	588	285,688	.	146,839	1,813	15,207	125	75,516	256	45,033	186	573	141
71	Rents	589	35,300	.	19,524	206	2,417	13	7,831	26	5,183	18	56	26
72	Maint Supv & Engineering	590	101,784	.	51,055	624	5,362	43	26,060	88	18,061	148	281	63
73	Maint of Station Equip	592	18,557	.	8,527	114	783	8	4,961	17	4,085	12	38	11
74	Maint of OH Lines	593	985,327	.	492,701	6,028	51,649	415	249,781	845	180,842	614	1,889	563
75	Maint of UG Lines	594	40,313	.	22,028	256	2,458	17	10,310	35	5,090	25	77	18
76	Maint of Line Transformers	595	8,064	.	4,957	28	891	3	2,147	8	0	7	20	4
77	Maint of Lighting	596	942	.	0	0	0	0	0	0	0	471	471	0
78	Maint of Misc. Plant	599	80,194	.	43,865	466	5,403	30	18,070	60	11,796	182	268	56
79	Total DISTR. O&M EXP.	500-599	1,602,629	.	816,716	9,707	88,835	663	404,861	1,362	273,360	1,801	3,819	1,505
80	Distribution Expense		1,602,629		816,716	9,707	88,835	663	404,861	1,362	273,360	1,801	3,819	1,505
81	**D. CUSTOMER ACCOUNTS AND SERVICE**													
82	Supervision	901	0	.	0	0	0	0	0	0	0	0	0	0
83	Meter Reading Exp	902	16,544	.	9,950	56	1,788	2	3,584	9	898	0	0	257
84	Customer Records & Coll	903	1,047,510	.	828,534	4,662	148,859	161	62,231	161	2,257	0	0	645
85	Uncollectible Accounts	904	20,000	.	17,398	128	331	1	1,334	1	764	0	35	8
86	Subtotal - Cust. Accts. Exp.	901-905	1,084,054	.	855,882	4,846	150,978	164	67,149	171	3,919	0	35	909
87														
88	Customer Assistance	908	9,737	.	7,702	43	1,384	1	578	1	21	0	0	6
89	OPEN	916	0	.	0	0	0	0	0	0	0	0	0	0
90	Subtotal - Cust. Svce. & Info.	908-916	9,737	.	7,702	43	1,384	1	578	1	21	0	0	6
91	Total CUST. ACCT. & SERV	901-919	1,093,791	.	863,584	4,889	152,362	166	67,728	173	3,940	0	35	915
92														

Total
Class Allocations- Total
Tot
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Wellsboro Electric Company
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FPFTY Ending December 31, 2026
Class Allocations- Total

Line	Account	No.	Balance		RS	RSAE	NRS	NRH	CS	CSH	IS	MSL	POL	EX
93	**E. ADMINISTRATIVE AND GENERAL**													
94	Admin. & Gen'l. Salaries	920	911,229	.	562,716	4,910	81,345	282	163,656	531	94,363	826	1,516	1,084
95	Office Supplies & Expenses	921	109,710	.	67,750	591	9,794	34	19,704	64	11,361	99	182	130
96	Outside Services Employed	923	154,525	.	89,733	846	12,257	53	31,983	105	18,761	223	368	197
97	Property Insurance	924	61,410	.	33,831	340	4,382	23	13,922	46	8,485	126	193	63
98	Employee Pensions & Benefits	926	0	.	0	0	0	0	0	0	0	0	0	0
99	Regulatory Comm. Expense	928	153,393	.	84,979	852	11,062	56	33,904	114	20,813	659	819	134
100	Misc. General Expense	930	110,581	.	64,214	605	8,771	38	22,888	75	13,425	159	263	141
101	Rents	931	2,200	.	1,359	12	196	1	395	1	228	2	4	3
102	Maint General Property	932	93,311	.	51,405	517	6,658	34	21,154	71	12,892	192	293	95
103	Total A&G Expense	920-932	1,596,359	.	955,987	8,674	134,466	519	307,606	1,007	180,328	2,287	3,638	1,848
104														
105	TOTAL OPERATING EXPE		4,292,779	.	2,636,287	23,270	375,663	1,348	780,195	2,542	457,628	4,088	7,491	4,268
106														
107	**II. DEPRECIATION EXPENSE**													
108	Intangible Plant		0	.	0	0	0	0	0	0	0	0	0	0
109	Station Equipment		252,375	.	115,961	1,551	10,652	111	67,466	229	55,557	170	522	156
110	Poles, Towers and Fixtures		509,675	.	256,062	3,098	27,240	212	127,520	431	93,543	312	962	295
111	OH Conductors and Devices		263,041	.	131,530	1,609	13,788	111	66,681	226	48,277	164	504	150
112	UG Conduits and Conductors		44,951	.	24,562	286	2,741	19	11,496	39	5,675	28	86	20
113	Line Transformers		116,555	.	71,646	403	12,872	45	31,034	111	0	95	293	56
114	Services		95,347	.	70,700	398	12,702	14	11,102	29	403	0	0	0
115	Meters		79,809	.	48,002	270	8,624	9	17,290	45	4,331	0	0	1,237
116	Install. Customers' premises		53,884	.	42,620	240	7,657	8	3,201	8	116	0	0	33
117	Street Lighting & Signal		2,971	.	0	0	0	0	0	0	0	1,485	1,485	0
118	General Plant		520,797	.	321,610	2,806	46,491	161	93,535	303	53,932	472	866	619
119	Total DEPRECIATION Exp.	403	1,939,404	.	1,082,693	10,661	142,769	690	429,324	1,421	261,834	2,726	4,718	2,567
120														
121	**III. TAXES and OTHER**													
122	**A. GENERAL TAXES**													
123	Payroll related	408	0	.	0	0	0	0	0	0	0	0	0	0
124	PURTA, Real estate	408.16	43,311	.	23,860	240	3,090	16	9,819	33	5,984	89	136	44
125	Capital stock		0	.	0	0	0	0	0	0	0	0	0	0
126	Other	408	837	.	461	5	60	0	190	1	116	2	3	1
127	Subtotal - General Taxes		44,148	.	24,321	245	3,150	16	10,008	33	6,100	91	139	45
128														
129	**B. GROSS RECEIPTS TAX**													
130	Gross Receipts tax		375,778	.	198,103	1,439	28,954	40	89,095	61	51,961	796	4,801	528
131	Subtotal- Gross Receipts tax		375,778	.	198,103	1,439	28,954	40	89,095	61	51,961	796	4,801	528
132														

Total
Class Allocations- Total
Tot
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Wellsboro Electric Company
Embedded Cost of Service Study (ECOSS) (R)
FPFTY Ending December 31, 2026
Class Allocations- Total

Line	Account	No.	Balance		RS	RSAE	NRS	NRH	CS	CSH	IS	MSL	POL	EX
133	**B. FEDERAL / STATE INCOME TAXES**													
134	State Income Tax Expense		(64,035)	.	(35,375)	(354)	(4,598)	(23)	(14,448)	(48)	(8,792)	(131)	(200)	(65)
135	Federal Income Tax Expense		(56,996)	.	(31,486)	(315)	(4,093)	(21)	(12,860)	(43)	(7,825)	(116)	(178)	(58)
136	Subtotal - Fed / State Inc Tax	409-411	(121,031)	.	(66,861)	(669)	(8,691)	(44)	(27,309)	(91)	(16,617)	(247)	(378)	(124)
137	Total TAXES	408-411	298,895	.	155,563	1,014	23,414	12	71,794	3	41,444	640	4,562	450
138														
139	**TOTAL EXPENSES**		6,531,077	.	3,874,542	34,945	541,846	2,050	1,281,314	3,966	760,906	7,454	16,771	7,285
140														
141	**IV. OPERATING REVENUES at Present Rates**													
142	Distribution Revenue		6,369,121	.	3,357,674	24,383	490,753	676	1,510,082	1,028	880,700	13,496	81,371	8,957
143	Forfeited Discounts		30,962	.	26,934	198	513	1	2,066	1	1,183	0	54	12
144	Rent For Electric Property		273,619	.	137,467	1,663	14,624	114	68,459	231	50,219	168	516	158
145	Other Electric Revenues		22,899	.	12,072	88	1,764	2	5,429	4	3,166	49	293	32
146	Total REVENUES		6,696,602	.	3,534,147	26,332	507,654	794	1,586,036	1,264	935,269	13,713	82,234	9,159
147														
148	TOTAL EXPENSES		6,531,077	.	3,874,542	34,945	541,846	2,050	1,281,314	3,966	760,906	7,454	16,771	7,285
149	**V. NET INCOME at Present Rates**		165,524	.	(340,395)	(8,613)	(34,191)	(1,256)	304,723	(2,702)	174,363	6,259	65,463	1,874
150														
151	**SUMMARY REPORT**													
152	OPERATING REVENUES													
153	Utility Revenues	440-446	6,400,084	.	3,384,608	24,581	491,266	678	1,512,148	1,029	881,884	13,496	81,425	8,968
154	Other Operating Revenues	450-456	296,518	.	149,539	1,751	16,388	116	73,888	235	53,385	216	809	191
155	Total Operating Revenues		6,696,602	.	3,534,147	26,332	507,654	794	1,586,036	1,264	935,269	13,713	82,234	9,159
156														
157	OPERATING EXPENSES													
158	Distribution / Transmission	580-599	1,602,629	.	816,716	9,707	88,835	663	404,861	1,362	273,360	1,801	3,819	1,505
159	Customer Acctg & Service	901-919	1,093,791	.	863,584	4,889	152,362	166	67,728	173	3,940	0	35	915
160	Admin & General	920-932	1,596,359	.	955,987	8,674	134,466	519	307,606	1,007	180,328	2,287	3,638	1,848
161	Total Operating Expenses		4,292,779	.	2,636,287	23,270	375,663	1,348	780,195	2,542	457,628	4,088	7,491	4,268
162														
163	Depreciation Expense	403	1,939,404	.	1,082,693	10,661	142,769	690	429,324	1,421	261,834	2,726	4,718	2,567
164	Taxes Other Than Income	408	419,926	.	222,424	1,683	32,105	56	99,103	94	58,061	887	4,940	574
165	INCOME BEFORE INCOME		44,493	.	(407,257)	(9,282)	(42,882)	(1,300)	277,414	(2,793)	157,745	6,012	65,085	1,751
166	Income Taxes	409-411	(121,031)	.	(66,861)	(669)	(8,691)	(44)	(27,309)	(91)	(16,617)	(247)	(378)	(124)
167	**NET INCOME**		165,524	.	(340,395)	(8,613)	(34,191)	(1,256)	304,723	(2,702)	174,363	6,259	65,463	1,874
168														
169	**RATE BASE**		25,974,028	.	14,389,602	144,196	1,873,193	9,464	5,741,037	19,230	3,524,195	111,670	138,695	22,745
170	Return on Rate Base		0.64%											
171														

Total
Class Allocations- Total
Tot
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Wellsboro Electric Company
Embedded Cost of Service Study (ECOSS) (R)
FPFTY Ending December 31, 2026
Class Allocations- Total

Line	Account	No.	Balance		RS	RSAE	NRS	NRH	CS	CSH	IS	MSL	POL	EX
172	**REVENUE REQUIREMENTS**													
173	Target Rate of Return		8.1800%		8.1800%	8.1800%	8.1800%	8.1800%	8.1800%	8.1800%	8.1800%	8.1800%	8.1800%	8.1800%
174														
175	Rate Base		25,974,028	.	14,389,602	144,196	1,873,193	9,464	5,741,037	19,230	3,524,195	111,670	138,695	22,745
176														
177	Operating expenses		4,119,386	.	2,533,909	22,291	364,270	1,291	744,956	2,427	436,051	3,428	6,637	4,126
178	Uncollectibles expense		20,000	.	17,398	128	331	1	1,334	1	764	0	35	8
179	Depreciation expense		1,939,404	.	1,082,693	10,661	142,769	690	429,324	1,421	261,834	2,726	4,718	2,567
180	Regulatory Commission Expenses		153,393	.	84,504	850	10,945	56	34,774	116	21,193	315	482	157
181	General taxes / Other		44,148	.	24,321	245	3,150	16	10,008	33	6,100	91	139	45
182	Subtotal- Operating Costs to recover		6,276,330	.	3,742,826	34,174	521,465	2,055	1,220,397	3,998	725,943	6,560	12,010	6,902
183														
184	Target Return on Rate Base- After tax		2,124,675		1,177,069	11,795	153,227	774	469,617	1,573	288,279	9,135	11,345	1,861
185														
186	Income taxes to recover		600,542	.	332,700	3,334	43,310	219	132,738	445	81,482	2,582	3,207	526
187														
188	Subtotal- Rev Req before GRT		9,001,548	.	5,252,595	49,303	718,002	3,048	1,822,752	6,016	1,095,704	18,277	26,562	9,289
189	GRT needed		543,858	.	318,269	2,969	43,959	184	109,523	362	65,278	1,132	1,611	570
190	**TOTAL REVENUE REQUIREMEN**		9,545,405	.	5,570,864	52,272	761,961	3,231	1,932,275	6,378	1,160,983	19,409	28,173	9,859
191														
192	Revenue at Present rates		6,696,602		3,534,147	26,332	507,654	794	1,586,036	1,264	935,269	13,713	82,234	9,159
193	Revenue Excess (Deficiency)		(2,848,804)		(2,036,717)	(25,940)	(254,307)	(2,437)	(346,238)	(5,114)	(225,714)	(5,696)	54,060	(700)
194														

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Revenue
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Wellsboro Electric Company
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FPFTY Ending December 31, 2026
TOTAL REVENUE REQUIREMENT

	Account Description	Total Dollars	RS	RSAE	NRS	NRH	CS	CSH	IS	MSL	POL	EX
1	**Demand-related**											
2	Primary	5,174,817	2,377,668	31,813	218,392	2,272	1,383,377	4,704	1,139,235	3,474	10,690	3,190
3	Secondary	624,118	318,783	4,265	29,281	402	267,323	940	(13)	769	2,367	(0)
4		5,798,935	2,696,452	36,078	247,673	2,674	1,650,699	5,645	1,139,222	4,244	13,057	3,190
5	NCP-Primary	20,036	9,206	123	846	9	5,356	18	4,411	13	41	12
6	Per kW / month-Demand	24.12	24.41	24.41	24.41	25.34	25.68	25.83	21.52	26.28	26.27	21.52
7												
8	kWh-Meter	105,165,077	44,639,052	394,372	4,657,346	6,256	28,611,970	7,216	26,746,293	0	0	102,572
9	Per kWh-Meter	$0.05514	$0.06041	$0.09148	$0.05318	$0.42750	$0.05769	$0.78226	$0.04259	#DIV/0!	#DIV/0!	$0.03110
10												
11	**Customer-related**											
12	Secondary	1,162,818	884,722	4,978	158,957	172	81,871	212	1,051	15,158	15,156	542
13	Billing	2,583,653	1,989,690	11,216	355,331	385	199,705	522	20,710	8	(40)	6,127
14		3,746,471	2,874,412	16,194	514,288	557	281,575	734	21,760	15,165	15,116	6,668
15	Number of Bills	77,969	61,670	347	11,080	12	4,632	12	168	0	0	48
16	Per bill	$48.05	$46.61	$46.67	$46.42	$46.41	$60.79	$61.14	$129.53	-	-	$138.92
17												
18	Total revenue requirement	9,545,405	5,570,864	52,272	761,961	3,231	1,932,275	6,378	1,160,983	19,409	28,173	9,859
19												
20	**Demand-related**											
21	Primary	$21.52	$21.52	$21.52	$21.52	$21.53	$21.52	$21.53	$21.52	$21.52	$21.51	$21.52
22	Secondary	$2.60	$2.89	$2.89	$2.89	$3.81	$4.16	$4.30	($0.00)	$4.76	$4.76	($0.00)
23		$24.12	$24.41	$24.41	$24.41	$25.34	$25.68	$25.83	$21.52	$26.28	$26.27	$21.52

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Tot
E-1C (R)

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FPFTY Ending December 31, 2026
TOTAL REVENUE REQUIREMENT

	Account Description		Total Dollars	RS	RSAE	NRS	NRH	CS	CSH	IS	MSL	POL	EX
1	Services, cost	Acct 369	2,486,089	1,843,433	10,372	331,202	359	289,474	750	10,499	0	0	0
2	Services, Acc Depr	Portion Acct 108	(1,472,321)	(1,091,724)	(6,143)	(196,146)	(212)	(171,433)	(444)	(6,218)	0	0	0
3	Meters, cost	Acct 370	1,041,481	626,404	3,525	112,544	122	225,632	585	56,521	0	0	16,149
4	Meters, Acc Depr	Portion Acct 108	(787,559)	(473,682)	(2,665)	(85,104)	(92)	(170,621)	(442)	(42,741)	0	0	(12,212)
5	ADIT- Service / Meter	Portion Acct 154	(4,063)	(2,873)	(15)	(537)	(1)	(546)	(1)	(70)	0	0	(19)
6	Service / Meter-Related Rate Base		1,263,627	901,557	5,073	161,958	175	172,506	447	17,991	0	0	3,918
7	Rate of return on rate base		8.18%	8.18%	8.18%	8.18%	8.18%	8.18%	8.18%	8.18%	8.18%	8.18%	8.18%
8	Return on Service / Meter rate base		103,365	73,747	415	13,248	14	14,111	37	1,472	0	0	321
9	Income tax gross-up		29,216	20,845	117	3,745	4	3,988	10	416	0	0	91
10	GRT gross-up		8,033	5,732	32	1,040	1	1,088	3	112	0	0	25
11	Customer-charge return component		140,614	100,324	564	18,033	20	19,187	50	2,000	0	0	436
12													
13	Meter expenses	Acct 586	39,903	24,000	135	4,312	5	8,645	22	2,166	0	0	619
14	Meter reading expenses	Acct 902	16,544	9,950	56	1,788	2	3,584	9	898	0	0	257
15	Service / Meter / EDI depr / amo	Portion Acct 403	175,156	118,701	668	21,327	23	28,392	74	4,734	0	0	1,237
16	Customer records and collection	Acct 903	1,047,510	828,534	4,662	148,859	161	62,231	161	2,257	0	0	645
17	Customer assistance	Acct 908	9,737	7,702	43	1,384	1	578	1	21	0	0	6
18	Employee benefits, taxes		0	0	0	0	0	0	0	0	0	0	0
19	Customer-charge expense component		1,288,851	988,887	5,564	177,669	192	103,430	268	10,075	0	0	2,764
20													
21	Customer-charge expense component		1,429,465	1,089,211	6,129	195,703	212	122,617	318	12,075	0	0	3,200
22													
23	Number of Bills		77,969	61,670	347	11,080	12	4,632	12	168	0	0	48
24													
25	**Customer-charge Components**		**$18.33**	**$17.66**	**$17.66**	**$17.66**	**$17.66**	**$26.47**	**$26.47**	**$71.88**	**-**	**-**	**$66.67**
26													
27	Distribution Plant in Service- Cost		34,485,748	18,338,822	192,479	2,283,478	13,216	8,284,030	27,771	5,107,173	82,218	122,912	33,650
28	Services / Meters % of Distribution Plant		10.2%	13.5%	7.2%	19.4%	3.6%	6.2%	4.8%	1.3%	0.0%	0.0%	48.0%
29	ADIT		(38,728)	(21,335)	(214)	(2,763)	(14)	(8,780)	(29)	(5,351)	(80)	(122)	(40)
30													
31	Income tax gross-up		28.27%	28.27%	28.27%	28.27%	28.27%	28.27%	28.27%	28.27%	28.27%	28.27%	28.27%
32	GRT gross-up		6.04%	6.06%	6.02%	6.12%	6.03%	6.01%	6.02%	5.96%	6.20%	6.07%	6.13%

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Line	Account	No.	Balance	Allocator	Primary	Secondary	Billing		Labor Cost	Labor %
					4	5	6			
1	**I. ELECTRIC PLANT IN SERVICE**									
2	INTANGIBLE PLANT									
3	EDI Software	303	284,588	Bill	0	0	284,588	-		
4	Total INTANGIBLE Plant		284,588		0	0	284,588	-		
5										
6	**C. TRANSMISSION PLANT**							-		
7	Transmission Plant	361	0	Tran	0	0	0	-		
8	Total TRANSMISSION Plant	350-359	0		0	0	0	-		
9										
10	**D. DISTRIBUTION PLANT**									
11	Land & Land Rights	360	178,334	Prim	178,334	0	0	-		
12	Structures and improvements	361	0	Prim	0	0	0	-		
13	Station Equipment	362	3,992,800	Prim	3,992,800	0	0	-		
14	Poles, Tower & Fixtures	364	14,933,172	OH_Cond	12,450,184	2,482,988	0	-		
15	OH Conductors & Devices	365	6,804,947	OH_Cond	5,673,466	1,131,481	0	-		
16	UG Conduits and Conductors	366	1,038,449	UG_Cond	595,569	442,880	0	-		
17	Line Transformers	368	3,365,587	Trans	0	3,365,587	0	-		
18	Services	369	2,486,089	Sec	0	2,486,089	0	-		
19	Meters	370	1,041,481	Bill	0	0	1,041,481	-		
20	Install. Customers' premises	371	519,618	Bill	0	0	519,618	-		
21	Street Lighting & Signal	373	125,272	Sec	0	125,272	0	-		
22	Total DISTRIBUTION Plant	360-373	34,485,748		22,890,353	10,034,297	1,561,098	-		
23										
24	**E. GENERAL PLANT**									
25	General Plant	389	9,778,618	Labor	4,463,905	1,224,546	4,090,167	-		
26	Communication Equip	398	117,901	Labor	53,821	14,764	49,315	-		
27	Total GENERAL Plant	389-399	9,896,519		4,517,727	1,239,311	4,139,482	-		
28										
29	**TOTAL UTILITY PLANT**		44,666,856		27,408,080	11,273,608	5,985,168	-		
30										

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Line	Account	No.	Balance	Allocator	Primary	Secondary	Billing		Labor Cost	Labor %
					4	5	6			
31	**II. DEPRECIATION RESERVE**									
32	Intangible Plant		284,588	IntanPt	0	0	284,588	-		
33	Transmission Plant		0	TranPt	0	0	0	-		
34	Structures and improvements		0	Prim	0	0	0	-		
35	Station Equipment		3,892,596	Prim	3,892,596	0	0	-		
36	Poles, Towers and Fixtures		5,102,743	OH_Cond	4,254,293	848,450	0	-		
37	OH Conductors and Devices		2,322,844	OH_Cond	1,936,617	386,227	0	-		
38	UG Conduits and Conductors		779,669	UG_Cond	447,154	332,515	0	-		
39	Line Transformers		1,697,284	Trans	0	1,697,284	0	-		
40	Services		1,472,321	Sec	0	1,472,321	0	-		
41	Meters		787,559	Bill	0	0	787,559	-		
42	Install. Customers' premises		115,728	Bill	0	0	115,728	-		
43	Street Lighting & Signal		(63,042)	Sec	0	(63,042)	0	-		
44	General Plant		2,928,774	GenPtxL	1,336,975	366,761	1,225,037	-		
45	Total DEPRECIATION RESE	108	19,321,064		11,867,635	5,040,516	2,412,913	-		
46										
47	**III. OTHER RATE BASE ITEMS**									
48	Cash Working Capital	131	512,714	OpExp_Dist	231,267	64,868	216,579	-		
49	CWIP	131	0	Plant	0	0	0	-		
50	Materials & Supplies	255	302,296	OpExp_Dist	136,355	38,246	127,695	-		
51	Customer Deposits		(120,033)	Bill	0	0	(120,033)	-		
52	ADIT	154	(38,728)	Plant	(23,916)	(9,837)	(4,974)	-		
53	Accrued Pension / OPEB	182	(28,013)	Labor	(12,788)	(3,508)	(11,717)	-		
54	Total OTHER RATE BASE	131-283	628,236		330,918	89,769	207,549	-		
55										
56	**TOTAL RATE BASE**		25,974,028		15,871,362	6,322,861	3,779,805	-		
57			25,974,028							

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Line	Account	No.	Balance	Allocator	Primary	Secondary	Billing		Labor Cost	Labor %
					4	5	6			
58	**I. OPERATING AND MAINTENANCE EXPENSES**									
59	**B. TRANSMISSION EXPENSE**									
60	Transmission Expense		0	Tran	0	0	0	-	0	0
61	Total TRANSMISSION Expense		0		0	0	0			
62										
63	**C. DISTRIBUTION EXPENSE**									
64	Ops Supv & Engineering	580	0	D-Labor-Op	0	0	0	-	0	0.0%
65	Station Expenses	582	0	Prim	0	0	0	-	0	0.0%
66	OH Line Expenses	583	6,020	OH_Cond	5,019	1,001	0	-	4,098	68.1%
67	Street Lighting Expenses	585	267	Sec	0	267	0	-	182	68.2%
68	Meter Expenses	586	39,903	Bill	0	0	39,903	-	26,981	67.6%
69	Customer Install. expense	587	267	Bill	0	0	267	-	182	68.2%
70	Misc. Distribution Expenses	588	285,688	OH_UG	204,569	81,120	0	-	140,466	49.2%
71	Rents	589	35,300	DistPt	23,431	10,271	1,598	-	0	0.0%
72	Maint Supv & Engineering	590	101,784	D-Labor-Mnt	81,926	19,398	459	-	42,663	41.9%
73	Maint of Station Equip	592	18,557	Prim	18,557	0	0	-	1,924	10.4%
74	Maint of OH Lines	593	985,327	OH_Cond	821,493	163,834	0	-	314,995	32.0%
75	Maint of UG Lines	594	40,313	UG_Cond	23,120	17,193	0	-	4,638	11.5%
76	Maint of Line Transformers	595	8,064	Trans	0	8,064	0	-	3,447	42.7%
77	Maint of Lighting	596	942	Sec	0	942	0	-	641	68.1%
78	Maint of Misc. Plant	599	80,194	DistPt	53,230	23,334	3,630	-	36,073	45.0%
79	Total DISTR. O&M EXP.	500-599	1,602,629		1,231,346	325,425	45,858	-	576,293	
80	Distribution Expense		1,602,629		1,231,346	325,425	45,858	-		
81	**D. CUSTOMER ACCOUNTS AND SERVICE**									
82	Supervision	901	0	None	0	0	0	-	0	0.0%
83	Meter Reading Exp	902	16,544	Bill	0	0	16,544	-	11,261	68.1%
84	Customer Records & Coll	903	1,047,510	Bill	0	0	1,047,510	-	353,116	33.7%
85	Uncollectible Accounts	904	20,000	Bill	0	0	20,000	-	0	0.0%
86	Subtotal - Cust. Accts. Exp.	901-905	1,084,054		0	0	1,084,054	-	364,377	
87										
88	Customer Assistance	908	9,737	Bill	0	0	9,737	-	161	1.7%
89	OPEN	916	0	None	0	0	0	-	0	0.0%
90	Subtotal - Cust. Svce. & Info.	908-916	9,737		0	0	9,737	-	161	
91	Total CUST. ACCT. & SERV.	901-919	1,093,791		0	0	1,093,791	-	364,538	
92									940,831	

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Line	Account	No.	Balance	Allocator	Primary	Secondary	Billing		Labor Cost	Labor %
					4	5	6			
93	**E. ADMINISTRATIVE AND GENERAL**									
94	Admin. & Gen'l. Salaries	920	911,229	Labor	415,973	114,110	381,146	-		
95	Office Supplies & Expenses	921	109,710	Labor	50,082	13,739	45,889	-		
96	Outside Services Employed	923	154,525	Labor_Pt	82,983	29,301	42,241	-		
97	Property Insurance	924	61,410	Plant	37,923	15,599	7,888	-		
98	Employee Pensions & Benefits	926	0	Labor	0	0	0	-		
99	Regulatory Comm. Expense	928	153,393	Bill	0	0	153,393	-		
100	Misc. General Expense	930	110,581	Labor_Pt	59,384	20,968	30,228	-		
101	Rents	931	2,200	Labor	1,004	275	920	-		
102	Maint General Property	932	93,311	Plant	57,624	23,702	11,985	-		
103	Total A&G Expense	920-932	1,596,359		704,974	217,695	673,690	-		
104										
105	TOTAL OPERATING EXPENSES		4,292,779		1,936,320	543,119	1,813,339	-		
106										
107	**II. DEPRECIATION EXPENSE**									
108	Intangible Plant		0	IntanPt	0	0	0	-		
109	Station Equipment		252,375	Prim	252,375	0	0	-		
110	Poles, Towers and Fixtures		509,675	OH_Cond	424,929	84,745	0	-		
111	OH Conductors and Devices		263,041	OH_Cond	219,304	43,737	0	-		
112	UG Conduits and Conductors		44,951	UG_Cond	25,780	19,171	0	-		
113	Line Transformers		116,555	Trans	0	116,555	0	-		
114	Services		95,347	Sec	0	95,347	0	-		
115	Meters		79,809	Bill	0	0	79,809	-		
116	Install. Customers' premises		53,884	Bill	0	0	53,884	-		
117	Street Lighting & Signal		2,971	Sec	0	2,971	0	-		
118	General Plant		520,797	GenPtxL	237,742	65,218	217,837	-		
119	Total DEPRECIATION Exp.	403	1,939,404		1,160,130	427,743	351,530	-		
120										
121	**III. TAXES and OTHER**									
122	**A. GENERAL TAXES**									
123	Payroll related	408.3	0	None	0	0	0	-		
124	PURTA, Real estate	408.16	43,311	Plant	26,747	11,001	5,563	-		
125	Capital stock		0	RateBase	0	0	0	-		
126	Other	408.1	837	Plant	517	213	108	-		
127	Subtotal - General Taxes		44,148		27,263	11,214	5,670	-		
128										
129	**B. GROSS RECEIPTS TAX**									
130	Gross Receipts tax		375,778	GRT_RevxT	198,083	68,948	108,747	-		
131	Subtotal- Gross Receipts tax		375,778		198,083	68,948	108,747	-		
132										

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Line	Account	No.	Balance	Allocator	Primary	Secondary	Billing		Labor Cost	Labor %
					a	c	b			
133	**B. FEDERAL / STATE INCOME TAXES**									
134	State Income Tax Expense		(64,035)	StaTax	(40,219)	(23,816)	0	-		
135	Federal Income Tax Expense		(56,996)	FedTax	(35,798)	(21,198)	0	-		
136	Subtotal - Fed / State Inc Tax	409-411	(121,031)		(76,017)	(45,015)	0	-		
137	Total TAXES	408-411	298,895		149,330	35,147	114,418	-		
138										
139	**TOTAL EXPENSES**		6,531,077		3,245,780	1,006,009	2,279,288	-		
140										
141	**IV. OPERATING REVENUES at Present Rates**									
142	Distribution Revenue		6,369,121	DistBill_RR-PF	3,373,660	1,174,288	1,821,174	-		
143	Forfeited Discounts		30,962	Bill	0	0	30,962	-		
144	Rent For Electric Property		273,619	OH_Cond	228,123	45,496	0	-		
145	Other Electric Revenues		22,899	DistBill_RR-PF	12,129	4,222	6,548	-		
146	Total REVENUES		6,696,602		3,613,913	1,224,005	1,858,684	-		
147										
148	TOTAL EXPENSES		6,531,077		3,245,780	1,006,009	2,279,288	-		
149	**V. NET INCOME at Present Rates**		165,524		368,132	217,996	(420,604)	-		
150			165,524							
151	**SUMMARY REPORT**									
152	OPERATING REVENUES									
153	Utility Revenues	440-446	6,400,084		3,373,660	1,174,288	1,852,136	-		
154	Other Operating Revenues	450-456	296,518		240,253	49,717	6,548	-		
155	Total Operating Revenues		6,696,602		3,613,913	1,224,005	1,858,684	-		
156										
157	OPERATING EXPENSES									
158	Distribution / Transmission	580-599	1,602,629		1,231,346	325,425	45,858	-		
159	Customer Acctg & Service	901-919	1,093,791		0	0	1,093,791	-		
160	Admin & General	920-932	1,596,359		704,974	217,695	673,690	-		
161	Total Operating Expenses		4,292,779		1,936,320	543,119	1,813,339	-		
162										
163	Depreciation Expense	403	1,939,404		1,160,130	427,743	351,530	-		
164	Taxes Other Than Income	408	419,926		225,346	80,162	114,418	-		
165	INCOME BEFORE INCOME TAXES		44,493		292,116	172,981	(420,604)	-		
166	Income Taxes	409-411	(121,031)		(76,017)	(45,015)	0	-		
167	**NET INCOME**		165,524		368,132	217,996	(420,604)	-		
168										
169	**RATE BASE**		25,974,028		15,871,362	6,322,861	3,779,805	-		
170	Return on Rate Base		0.6%		2.3%	3.4%	(11.1%)			
171										

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Line	Account	No.	Balance	Allocator	Primary	Secondary	Billing		Labor Cost	Labor %
					4	5	6			
172	**REVENUE REQUIREMENTS**									
173	Target Rate of Return		8.1800%		8.1800%	8.1800%	8.1800%			
174										
175	Rate Base		25,974,028		15,871,362	6,322,861	3,779,805	-		
176								-		
177	Operating expenses		4,119,386		1,936,320	543,119	1,639,947	-		
178	Uncollectibles expense		20,000	BILL	0	0	20,000	-		
179	Depreciation expense		1,939,404		1,160,130	427,743	351,530	-		
180	Regulatory Commission Expenses		153,393	Plant	94,727	38,963	19,702	-		
181	General taxes / Other		44,148		27,263	11,214	5,670	-		
182	Subtotal- Operating Costs to recover		6,276,330		3,218,441	1,021,040	2,036,850	-		
183										
184	Target Return on Rate Base- After tax		2,124,675		1,298,277	517,210	309,188	-		
185										
186	Income taxes to recover		600,542	28.27%	366,960	146,190	87,392	-		
187				22.04%						
188	Subtotal- Rev Req before GRT		9,001,548		4,883,678	1,684,440	2,433,430	-		
189	GRT needed		543,858	6.27%	291,139	102,496	150,222	-		
190	**TOTAL REVENUE REQUIREMENT**		9,545,405		5,174,817	1,786,936	2,583,653	-		
191										
192	Revenue at Present rates		6,696,602		3,613,913	1,224,005	1,858,684	-		
193	Revenue Excess (Deficiency)		(2,848,804)		(1,560,905)	(562,930)	(724,969)	-		
194										

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Line	Account	No.	Secondary	Allocator	Demand	Customer
1	**I. ELECTRIC PLANT IN SERVICE**					
2	INTANGIBLE PLANT					
3	EDI Software	303	0	None	0	0
4	Total INTANGIBLE Plant		0		0	0
5						
6	**C. TRANSMISSION PLANT**					
7	Transmission Plant	361	0	None	0	0
8	Total TRANSMISSION Plant	350-359	0		0	0
9						
10	**D. DISTRIBUTION PLANT**					
11	Land & Land Rights	360	0	None	0	0
12	Structures and improvements	361	0	None	0	0
13	Station Equipment	362	0	None	0	0
14	Poles, Tower & Fixtures	364	2,482,988	PTF-Sec-Z	917,711	1,565,277
15	OH Conductors & Devices	365	1,131,481	OH-Sec-Z	497,461	634,020
16	UG Conduits and Conductors	366	442,880	UG-Sec-Z	282,151	160,729
17	Line Transformers	368	3,365,587	Trans-Min	755,617	2,609,971
18	Services	369	2,486,089	Customer	0	2,486,089
19	Meters	370	0	None	0	0
20	Install. Customers' premises	371	0	None	0	0
21	Street Lighting & Signal	373	125,272	Customer	0	125,272
22	Total DISTRIBUTION Plant	360-373	10,034,297		2,452,940	7,581,357
23						
24	**E. GENERAL PLANT**					
25	General Plant	389	1,224,546	Sec-Lab	624,974	599,572
26	Communication Equip	398	14,764	Sec-Lab	7,535	7,229
27	Total GENERAL Plant	389-399	1,239,311		632,509	606,802
28						
29	**TOTAL UTILITY PLANT**		11,273,608		3,085,449	8,188,159
30						

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Line	Account	No.	Secondary	Allocator	Demand	Customer
31	**II. DEPRECIATION RESEI**					
32	Intangible Plant		0	None	0	0
33	Transmission Plant		0	None	0	0
34	Structures and improvements		0	None	0	0
35	Station Equipment		0	None	0	0
36	Poles, Towers and Fixtures		848,450	PTF-Sec-Z	313,587	534,863
37	OH Conductors and Devices		386,227	OH-Sec-Z	169,806	216,420
38	UG Conduits and Conductors		332,515	UG-Sec-Z	211,840	120,675
39	Line Transformers		1,697,284	Trans-Min	381,062	1,316,223
40	Services		1,472,321	Customer	0	1,472,321
41	Meters		0	None	0	0
42	Install. Customers' premises		0	None	0	0
43	Street Lighting & Signal		(63,042)	Customer	0	(63,042)
44	General Plant		366,761	Sec-GenPt	187,185	179,577
45	Total DEPRECIATION RESE	108	5,040,516		1,263,479	3,777,037
46						
47	**III. OTHER RATE BASE I**					
48	Cash Working Capital	131	64,868	Sec-OpExp	30,650	34,218
49	CWIP	131	0	Sec-Pt	0	0
50	Materials & Supplies	255	38,246	Sec-OpExp	18,071	20,175
51	Customer Deposits		0	None	0	0
52	ADIT	154	(9,837)	Sec-Pt	(2,692)	(7,145)
53	Accrued Pension / OPEB	182	(3,508)	Sec-Lab	(1,790)	(1,718)
54	Total OTHER RATE BASE	131-283	89,769		44,238	45,531
55						
56	**TOTAL RATE BASE**		6,322,861		1,866,208	4,456,653
57						

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Line	Account	No.	Secondary	Allocator	Demand	Customer
58	**I. OPERATING AND MAIN**					
59	**B. TRANSMISSION EXPEI**					
60	Transmission Expense		0	None	0	0
61	Total TRANSMISSION Expe		0		0	0
62						
63	**C. DISTRIBUTION EXPEN**					
64	Ops Supv & Engineering	580	0	Sec-Lab	0	0
65	Station Expenses	582	0	None	0	0
66	OH Line Expenses	583	1,001	OH-Sec-Z	440	561
67	Street Lighting Expenses	585	267	Customer	0	267
68	Meter Expenses	586	0	None	0	0
69	Customer Install. expense	587	0	None	0	0
70	Misc. Distribution Expenses	588	81,120	Sec-OH_UG	56,434	24,685
71	Rents	589	10,271	Sec-Pt	2,811	7,460
72	Maint Supv & Engineering	590	19,398	Sec-Lab	9,900	9,498
73	Maint of Station Equip	592	0	None	0	0
74	Maint of OH Lines	593	163,834	OH-Sec-Z	72,030	91,803
75	Maint of UG Lines	594	17,193	UG-Sec-Z	10,953	6,240
76	Maint of Line Transformers	595	8,064	Trans-Min	1,810	6,253
77	Maint of Lighting	596	942	Customer	0	942
78	Maint of Misc. Plant	599	23,334	Sec-Pt	6,386	16,948
79	Total DISTR. O&M EXP.	500-599	325,425		160,766	164,659
80	Distribution Expense		325,425		160,766	164,659
81	**D. CUSTOMER ACCOUNTS AND S**					
82	Supervision	901	0	None	0	0
83	Meter Reading Exp	902	0	None	0	0
84	Customer Records & Coll	903	0	None	0	0
85	Uncollectible Accounts	904	0	None	0	0
86	Subtotal - Cust. Accts. Exp.	901-905	0		0	0
87						
88	Customer Assistance	908	0	None	0	0
89	OPEN	916	0	None	0	0
90	Subtotal - Cust. Svce. & Info.	908-916	0		0	0
91	Total CUST. ACCT. & SERV	901-919	0		0	0
92						

Classify
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Wellsboro Electric Company
Embedded Cost of Service Study (ECOSS) (R)
FPFTY Ending December 31, 2026
Classification

Line	Account	No.	Secondary [1]	Allocator	Demand [1]	Customer [3]
93	**E. ADMINISTRATIVE AND GENEF**					
94	Admin. & Gen'l. Salaries	920	114,110	Sec-Lab	58,239	55,872
95	Office Supplies & Expenses	921	13,739	Sec-Lab	7,012	6,727
96	Outside Services Employed	923	29,301	Sec-LabPt	11,487	17,814
97	Property Insurance	924	15,599	Sec-Pt	4,269	11,330
98	Employee Pensions & Benefits	926	0	Sec-Lab	0	0
99	Regulatory Comm. Expense	928	0	Sec-Pt	0	0
100	Misc. General Expense	930	20,968	Sec-LabPt	8,220	12,748
101	Rents	931	275	Sec-Lab	141	135
102	Maint General Property	932	23,702	Sec-Pt	6,487	17,215
103	Total A&G Expense	920-932	217,695		95,854	121,840
104						
105	TOTAL OPERATING EXPE		543,119		256,620	286,499
106						
107	**II. DEPRECIATION EXPENSE**					
108	Intangible Plant		0	None	0	0
109	Station Equipment		0	None	0	0
110	Poles, Towers and Fixtures		84,745	PTF-Sec-Z	31,322	53,423
111	OH Conductors and Devices		43,737	OH-Sec-Z	19,229	24,508
112	UG Conduits and Conductors		19,171	UG-Sec-Z	12,213	6,957
113	Line Transformers		116,555	Trans-Min	26,168	90,387
114	Services		95,347	Customer	0	95,347
115	Meters		0	None	0	0
116	Install. Customers' premises		0	None	0	0
117	Street Lighting & Signal		2,971	Customer	0	2,971
118	General Plant		65,218	Sec-GenPt	33,285	31,932
119	Total DEPRECIATION Exp.	403	427,743		122,217	305,525
120						
121	**III. TAXES and OTHER**					
122	**A. GENERAL TAXES**					
123	Payroll related	408	0	None	0	0
124	PURTA, Real estate	408.16	11,001	Sec-Pt	3,011	7,991
125	Capital stock		0	Sec-RB	0	0
126	Other	408	213	Sec-Pt	58	154
127	Subtotal - General Taxes		11,214		3,069	8,145
128						
129	**B. GROSS RECEIPTS TAX**					
130	Gross Receipts tax		68,948	Sec-Rev	24,406	44,541
131	Subtotal- Gross Receipts tax		68,948		24,406	44,541
132						

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Wellsboro Electric Company
Embedded Cost of Service Study (ECOSS) (R)
FPFTY Ending December 31, 2026
Classification

Line	Account	No.	Secondary	Allocator	Demand	Customer
133	**B. FEDERAL / STATE INCOME TA**					
134	State Income Tax Expense		(23,816)	Sec-StaTax	(3,810)	(20,006)
135	Federal Income Tax Expense		(21,198)	Sec-FedTax	(3,392)	(17,807)
136	Subtotal - Fed / State Inc Tax	409-411	(45,015)		(7,202)	(37,813)
137	Total TAXES	408-411	35,147		20,274	14,874
138						
139	**TOTAL EXPENSES**		1,006,009		399,112	606,898
140						
141	**IV. OPERATING REVENUES at Pre**					
142	Distribution Revenue		1,174,288	Sec-RetRRPF	415,680	758,608
143	Forfeited Discounts		0	None	0	0
144	Rent For Electric Property		45,496	PTF-Sec-Z	16,815	28,680
145	Other Electric Revenues		4,222	Sec-RetRRPF	1,494	2,727
146	Total REVENUES		1,224,005		433,989	790,016
147						
148	TOTAL EXPENSES		1,006,009		399,112	606,898
149	**V. NET INCOME at Present Rates**		217,996		34,878	183,118
150						
151	**SUMMARY REPORT**					
152	OPERATING REVENUES					
153	Utility Revenues	440-446	1,174,288		415,680	758,608
154	Other Operating Revenues	450-456	49,717		18,310	31,408
155	Total Operating Revenues		1,224,005		433,989	790,016
156						
157	OPERATING EXPENSES					
158	Distribution / Transmission	580-599	325,425		160,766	164,659
159	Customer Acctg & Service	901-919	0		0	0
160	Admin & General	920-932	217,695		95,854	121,840
161	Total Operating Expenses		543,119		256,620	286,499
162						
163	Depreciation Expense	403	427,743		122,217	305,525
164	Taxes Other Than Income	408	80,162		27,476	52,686
165	INCOME BEFORE INCOME		172,981		27,676	145,306
166	Income Taxes	409-411	(45,015)		(7,202)	(37,813)
167	**NET INCOME**		217,996		34,878	183,118
168						
169	**RATE BASE**		6,322,861		1,866,208	4,456,653
170	Return on Rate Base					
171						

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Wellsboro Electric Company
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FPFTY Ending December 31, 2026
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Line	Account	No.	Secondary	Allocator	Demand	Customer
172	**REVENUE REQUIREMENTS**					
173	Target Rate of Return		8.1800%		8.1800%	8.1800%
174						
175	Rate Base		6,322,861		1,866,208	4,456,653
176						
177	Operating expenses		543,119		256,620	286,499
178	Uncollectibles expense		0	None	0	0
179	Depreciation expense		427,743		122,217	305,525
180	Regulatory Commission Expenses		38,963	Sec-Pt	10,664	28,300
181	General taxes / Other		11,214		3,069	8,145
182	Subtotal- Operating Costs to recover		1,021,040		392,571	628,469
183						
184	Target Return on Rate Base- After tax		517,210		152,656	364,554
185						
186	Income taxes to recover	28.27%	146,190		43,148	103,042
187						
188	Subtotal- Rev Req before GRT		1,684,440		588,375	1,096,065
189	GRT needed	6.27%	102,496		35,743	66,753
190	**TOTAL REVENUE REQUIREMEN**		1,786,936		624,118	1,162,818
191						
192	Revenue at Present rates					
193	Revenue Excess (Deficiency)					
194						

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Wellsboro Electric Company
Embedded Cost of Service Study (ECOSS) (R)
FPFTY Ending December 31, 2026
Class Allocation- Primary Demand

Line	Account	No.	Balance	Allocator	RS	RSAE	NRS	NRH	CS	CSH	IS	MSL	POL	EX
1	**I. ELECTRIC PLANT IN SERVICE**													
2	INTANGIBLE PLANT													
3	EDI Software	303	0	PriD-Lab	0	0	0	0	0	0	0	0	0	0
4	Total INTANGIBLE Plant		0		0	0	0	0	0	0	0	0	0	0
5														
6	**C. TRANSMISSION PLANT**													
7	Transmission Plant	361	0	None	0	0	0	0	0	0	0	0	0	0
8	Total TRANSMISSION Plant	350-359	0		0	0	0	0	0	0	0	0	0	0
9														
10	**D. DISTRIBUTION PLANT**													
11	Land & Land Rights	360	178,334	NCP-Prim	81,941	1,096	7,527	78	47,673	162	39,258	120	369	110
12	Structures and improvements	361	0	NCP-Prim	0	0	0	0	0	0	0	0	0	0
13	Station Equipment	362	3,992,800	NCP-Prim	1,834,608	24,545	168,528	1,753	1,067,372	3,629	878,966	2,682	8,255	2,462
14	Poles, Tower & Fixtures	364	12,450,184	NCP-Prim	5,720,598	76,535	525,497	5,466	3,328,236	11,317	2,740,757	8,362	25,740	7,677
15	OH Conductors & Devices	365	5,673,466	NCP-Prim	2,606,838	34,876	239,465	2,491	1,516,655	5,157	1,248,945	3,811	11,729	3,499
16	UG Conduits and Conductors	366	595,569	NCP-Prim	273,652	3,661	25,138	261	159,210	541	131,107	400	1,231	367
17	Line Transformers	368	0	None	0	0	0	0	0	0	0	0	0	0
18	Services	369	0	None	0	0	0	0	0	0	0	0	0	0
19	Meters	370	0	None	0	0	0	0	0	0	0	0	0	0
20	Install. Customers' premises	371	0	None	0	0	0	0	0	0	0	0	0	0
21	Street Lighting & Signal	373	0	None	0	0	0	0	0	0	0	0	0	0
22	Total DISTRIBUTION Plant	360-373	22,890,353		10,517,637	140,713	966,155	10,050	6,119,146	20,807	5,039,033	15,374	47,324	14,115
23														
24	**E. GENERAL PLANT**													
25	General Plant	389	4,463,905	PriD-Lab	2,051,071	27,441	188,412	1,960	1,193,310	4,058	982,675	2,998	9,229	2,753
26	Communication Equip	398	53,821	PriD-Lab	24,730	331	2,272	24	14,388	49	11,848	36	111	33
27	Total GENERAL Plant	389-399	4,517,727		2,075,801	27,772	190,684	1,983	1,207,698	4,106	994,523	3,034	9,340	2,786
28														
29	**TOTAL UTILITY PLANT**		27,408,080		12,593,437	168,485	1,156,839	12,033	7,326,843	24,913	6,033,556	18,408	56,664	16,901
30														

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Wellsboro Electric Company
Embedded Cost of Service Study (ECOSS) (R)
FPFTY Ending December 31, 2026
Class Allocation- Primary Demand

Line	Account	No.	Balance	Allocator	RS	RSAE	NRS	NRH	CS	CSH	IS	MSL	POL	EX
31	**II. DEPRECIATION RESERVE**													
32	Intangible Plant		0	None	0	0	0	0	0	0	0	0	0	0
33	Transmission Plant		0	None	0	0	0	0	0	0	0	0	0	0
34	Structures and improvements		0	NCP-Prim	0	0	0	0	0	0	0	0	0	0
35	Station Equipment		3,892,596	NCP-Prim	1,788,566	23,929	164,299	1,709	1,040,585	3,538	856,908	2,614	8,048	2,400
36	Poles, Towers and Fixtures		4,254,293	NCP-Prim	1,954,758	26,152	179,565	1,868	1,137,276	3,867	936,531	2,857	8,795	2,623
37	OH Conductors and Devices		1,936,617	NCP-Prim	889,835	11,905	81,741	850	517,705	1,760	426,323	1,301	4,004	1,194
38	UG Conduits and Conductors		447,154	NCP-Prim	205,458	2,749	18,873	196	119,535	406	98,436	300	924	276
39	Line Transformers		0	None	0	0	0	0	0	0	0	0	0	0
40	Services		0	None	0	0	0	0	0	0	0	0	0	0
41	Meters		0	None	0	0	0	0	0	0	0	0	0	0
42	Install. Customers' premises		0	None	0	0	0	0	0	0	0	0	0	0
43	Street Lighting & Signal		0	None	0	0	0	0	0	0	0	0	0	0
44	General Plant		1,336,975	PriD-Lab	614,312	8,219	56,431	587	357,406	1,215	294,319	898	2,764	824
45	Total DEPRECIATION RESE	108	11,867,635		5,452,929	72,953	500,909	5,210	3,172,506	10,787	2,612,516	7,971	24,535	7,318
46														
47	**III. OTHER RATE BASE ITEMS**													
48	Cash Working Capital	131	231,267	PriD-OpExp	106,262	1,422	9,761	102	61,823	210	50,911	155	478	143
49	CWIP	131	0	PriD-Pt	0	0	0	0	0	0	0	0	0	0
50	Materials & Supplies	255	136,355	PriD-Pt	62,652	838	5,755	60	36,451	124	30,017	92	282	84
51	Customer Deposits		0	None	0	0	0	0	0	0	0	0	0	0
52	ADIT	154	(23,916)	PriD-Pt	(10,989)	(147)	(1,009)	(11)	(6,393)	(22)	(5,265)	(16)	(49)	(15)
53	Accrued Pension / OPEB	182	(12,788)	PriD-Lab	(5,876)	(79)	(540)	(6)	(3,418)	(12)	(2,815)	(9)	(26)	(8)
54	Total OTHER RATE BASE	131-283	330,918		152,050	2,034	13,967	145	88,462	301	72,848	222	684	204
55														
56	**TOTAL RATE BASE**		15,871,362		7,292,558	97,565	669,898	6,968	4,242,799	14,427	3,493,888	10,660	32,813	9,787
57														

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Wellsboro Electric Company
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FPFTY Ending December 31, 2026
Class Allocation- Primary Demand

Line	Account	No.	Balance	Allocator	RS	RSAE	NRS	NRH	CS	CSH	IS	MSL	POL	EX
58	**I. OPERATING AND MAINTENANCE EXPENSES**													
59	**B. TRANSMISSION EXPENSE**													
60	Transmission Expense		0	None	0	0	0	0	0	0	0	0	0	0
61	Total TRANSMISSION Expense		0		0	0	0	0	0	0	0	0	0	0
62														
63	**C. DISTRIBUTION EXPENSE**													
64	Ops Supv & Engineering	580	0	PriD-Lab	0	0	0	0	0	0	0	0	0	0
65	Station Expenses	582	0	NCP-Prim	0	0	0	0	0	0	0	0	0	0
66	OH Line Expenses	583	5,019	NCP-Prim	2,306	31	212	2	1,342	5	1,105	3	10	3
67	Street Lighting Expenses	585	0	None	0	0	0	0	0	0	0	0	0	0
68	Meter Expenses	586	0	None	0	0	0	0	0	0	0	0	0	0
69	Customer Install. expense	587	0	None	0	0	0	0	0	0	0	0	0	0
70	Misc. Distribution Expenses	588	204,569	NCP-Prim	93,995	1,258	8,634	90	54,686	186	45,033	137	423	126
71	Rents	589	23,431	NCP-Prim	10,766	144	989	10	6,264	21	5,158	16	48	14
72	Maint Supv & Engineering	590	81,926	PriD-Lab	37,643	504	3,458	36	21,901	74	18,035	55	169	51
73	Maint of Station Equip	592	18,557	NCP-Prim	8,527	114	783	8	4,961	17	4,085	12	38	11
74	Maint of OH Lines	593	821,493	NCP-Prim	377,459	5,050	34,674	361	219,605	747	180,842	552	1,698	507
75	Maint of UG Lines	594	23,120	NCP-Prim	10,623	142	976	10	6,181	21	5,090	16	48	14
76	Maint of Line Transformers	595	0	None	0	0	0	0	0	0	0	0	0	0
77	Maint of Lighting	596	0	None	0	0	0	0	0	0	0	0	0	0
78	Maint of Misc. Plant	599	53,230	NCP-Prim	24,458	327	2,247	23	14,230	48	11,718	36	110	33
79	Total DISTR. O&M EXP.	500-599	1,231,346		565,777	7,569	51,973	541	329,168	1,119	271,066	827	2,546	759
80	Distribution Expense		1,231,346		565,777	7,569	51,973	541	329,168	1,119	271,066	827	2,546	759
81	**D. CUSTOMER ACCOUNTS AND SERVICE**													
82	Supervision	901	0	None	0	0	0	0	0	0	0	0	0	0
83	Meter Reading Exp	902	0	None	0	0	0	0	0	0	0	0	0	0
84	Customer Records & Coll	903	0	None	0	0	0	0	0	0	0	0	0	0
85	Uncollectible Accounts	904	0	None	0	0	0	0	0	0	0	0	0	0
86	Subtotal - Cust. Accts. Exp.	901-905	0		0	0	0	0	0	0	0	0	0	0
87														
88	Customer Assistance	908	0	None	0	0	0	0	0	0	0	0	0	0
89	OPEN	916	0	None	0	0	0	0	0	0	0	0	0	0
90	Subtotal - Cust. Svce. & Info.	908-916	0		0	0	0	0	0	0	0	0	0	0
91	Total CUST. ACCT. & SERV	901-919	0		0	0	0	0	0	0	0	0	0	0
92														

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Wellsboro Electric Company
Embedded Cost of Service Study (ECOSS) (R)
FPFTY Ending December 31, 2026
Class Allocation- Primary Demand

Line	Account	No.	Balance	Allocator	RS	RSAE	NRS	NRH	CS	CSH	IS	MSL	POL	EX
93	**E. ADMINISTRATIVE AND GENERAL**													
94	Admin. & Gen'l. Salaries	920	415,973	PriD-Lab	191,131	2,557	17,557	183	111,200	378	91,571	279	860	257
95	Office Supplies & Expenses	921	50,082	PriD-Lab	23,012	308	2,114	22	13,388	46	11,025	34	104	31
96	Outside Services Employed	923	82,983	PriD-LabPt	38,129	510	3,503	36	22,183	75	18,268	56	172	51
97	Property Insurance	924	37,923	PriD-Pt	17,425	233	1,601	17	10,138	34	8,348	25	78	23
98	Employee Pensions & Benefits	926	0	PriD-Lab	0	0	0	0	0	0	0	0	0	0
99	Regulatory Comm. Expense	928	0	PriD-Pt	0	0	0	0	0	0	0	0	0	0
100	Misc. General Expense	930	59,384	PriD-LabPt	27,286	365	2,506	26	15,875	54	13,073	40	123	37
101	Rents	931	1,004	PriD-Lab	461	6	42	0	268	1	221	1	2	1
102	Maint General Property	932	57,624	PriD-Pt	26,477	354	2,432	25	15,404	52	12,685	39	119	36
103	Total A&G Expense	920-932	704,974		323,921	4,334	29,756	310	188,457	641	155,192	473	1,457	435
104														
105	TOTAL OPERATING EXPENSES		1,936,320		889,698	11,903	81,728	850	517,625	1,760	426,257	1,301	4,003	1,194
106														
107	**II. DEPRECIATION EXPENSE**													
108	Intangible Plant		0	None	0	0	0	0	0	0	0	0	0	0
109	Station Equipment		252,375	NCP-Prim	115,961	1,551	10,652	111	67,466	229	55,557	170	522	156
110	Poles, Towers and Fixtures		424,929	NCP-Prim	195,246	2,612	17,935	187	113,594	386	93,543	285	879	262
111	OH Conductors and Devices		219,304	NCP-Prim	100,766	1,348	9,256	96	58,625	199	48,277	147	453	135
112	UG Conduits and Conductors		25,780	NCP-Prim	11,845	158	1,088	11	6,892	23	5,675	17	53	16
113	Line Transformers		0	None	0	0	0	0	0	0	0	0	0	0
114	Services		0	None	0	0	0	0	0	0	0	0	0	0
115	Meters		0	None	0	0	0	0	0	0	0	0	0	0
116	Install. Customers' premises		0	None	0	0	0	0	0	0	0	0	0	0
117	Street Lighting & Signal		0	None	0	0	0	0	0	0	0	0	0	0
118	General Plant		237,742	PriD-Lab	109,237	1,461	10,035	104	63,554	216	52,336	160	492	147
119	Total DEPRECIATION Exp.	403	1,160,130		533,056	7,132	48,967	509	310,131	1,055	255,389	779	2,398	715
120														
121	**III. TAXES and OTHER**													
122	**A. GENERAL TAXES**													
123	Payroll related	408	0	None	0	0	0	0	0	0	0	0	0	0
124	PURTA, Real estate	408.16	26,747	PriD-Pt	12,289	164	1,129	12	7,150	24	5,888	18	55	16
125	Capital stock		0	RateBase	0	0	0	0	0	0	0	0	0	0
126	Other	408	517	PriD-Pt	237	3	22	0	138	0	114	0	1	0
127	Subtotal - General Taxes		27,263		12,527	168	1,151	12	7,288	25	6,002	18	56	17
128														
129	**B. GROSS RECEIPTS TAX**													
130	Gross Receipts tax		198,083	Dist_Rev	104,425	758	15,263	21	46,964	32	27,390	420	2,531	279
131	Subtotal- Gross Receipts tax		198,083		104,425	758	15,263	21	46,964	32	27,390	420	2,531	279
132														

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Wellsboro Electric Company
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Line	Account	No.	Balance	Allocator	RS	RSAE	NRS	NRH	CS	CSH	IS	MSL	POL	EX
133	**B. FEDERAL / STATE INCOME TAXES**													
134	State Income Tax Expense		(40,219)	PreStaTax	(22,218)	(222)	(2,888)	(15)	(9,075)	(30)	(5,522)	(82)	(125)	(41)
135	Federal Income Tax Expense		(35,798)	PreFedTax	(19,776)	(198)	(2,571)	(13)	(8,077)	(27)	(4,915)	(73)	(112)	(37)
136	Subtotal - Fed / State Inc Tax	409-411	(76,017)		(41,994)	(420)	(5,459)	(28)	(17,152)	(57)	(10,437)	(155)	(237)	(78)
137	Total TAXES	408-411	149,330		74,958	505	10,955	5	37,101	(0)	22,955	283	2,350	218
138														
139	**TOTAL EXPENSES**		3,245,780		1,497,712	19,540	141,650	1,365	864,857	2,814	704,601	2,363	8,751	2,127
140														
141	**IV. OPERATING REVENUES at Present Rates**													
142	Distribution Revenue		3,373,660	Dist_Rev	1,778,526	12,916	259,947	358	799,876	545	466,498	7,149	43,101	4,744
143	Forfeited Discounts		0	None	0	0	0	0	0	0	0	0	0	0
144	Rent For Electric Property		228,123	NCP-Prim	104,818	1,402	9,629	100	60,983	207	50,219	153	472	141
145	Other Electric Revenues		12,129	Dist_Rev	6,394	46	935	1	2,876	2	1,677	26	155	17
146	Total REVENUES		3,613,913		1,889,739	14,364	270,510	460	863,734	754	518,394	7,328	43,728	4,902
147														
148	TOTAL EXPENSES		3,245,780		1,497,712	19,540	141,650	1,365	864,857	2,814	704,601	2,363	8,751	2,127
149	**V. NET INCOME at Present Rates**		368,132		392,026	(5,176)	128,860	(905)	(1,123)	(2,060)	(186,207)	4,965	34,976	2,775
150														
151	**SUMMARY REPORT**													
152	OPERATING REVENUES													
153	Utility Revenues	440-446	3,373,660		1,778,526	12,916	259,947	358	799,876	545	466,498	7,149	43,101	4,744
154	Other Operating Revenues	450-456	240,253		111,212	1,449	10,563	101	63,859	209	51,896	179	627	158
155	Total Operating Revenues		3,613,913		1,889,739	14,364	270,510	460	863,734	754	518,394	7,328	43,728	4,902
156														
157	OPERATING EXPENSES													
158	Distribution / Transmission	580-599	1,231,346		565,777	7,569	51,973	541	329,168	1,119	271,066	827	2,546	759
159	Customer Acctg & Service	901-919	0		0	0	0	0	0	0	0	0	0	0
160	Admin & General	920-932	704,974		323,921	4,334	29,756	310	188,457	641	155,192	473	1,457	435
161	Total Operating Expenses		1,936,320		889,698	11,903	81,728	850	517,625	1,760	426,257	1,301	4,003	1,194
162														
163	Depreciation Expense	403	1,160,130		533,056	7,132	48,967	509	310,131	1,055	255,389	779	2,398	715
164	Taxes Other Than Income	408	225,346		116,952	926	16,413	33	54,253	57	33,392	438	2,587	295
165	INCOME BEFORE INCOME		292,116		350,032	(5,596)	123,402	(933)	(18,274)	(2,117)	(196,644)	4,810	34,739	2,697
166	Income Taxes	409-411	(76,017)		(41,994)	(420)	(5,459)	(28)	(17,152)	(57)	(10,437)	(155)	(237)	(78)
167	**NET INCOME**		368,132		392,026	(5,176)	128,860	(905)	(1,123)	(2,060)	(186,207)	4,965	34,976	2,775
168														
169	**RATE BASE**		15,871,362		7,292,558	97,565	669,898	6,968	4,242,799	14,427	3,493,888	10,660	32,813	9,787
170	Return on Rate Base		2.32%											
171														

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Line	Account	No.	Balance	Allocator	RS	RSAE	NRS	NRH	CS	CSH	IS	MSL	POL	EX
172	**REVENUE REQUIREMENTS**													
173	Target Rate of Return		8.1800%		8.1800%	8.1800%	8.1800%	8.1800%	8.1800%	8.1800%	8.1800%	8.1800%	8.1800%	8.1800%
174														
175	Rate Base		15,871,362		7,292,558	97,565	669,898	6,968	4,242,799	14,427	3,493,888	10,660	32,813	9,787
176														
177	Operating expenses		1,936,320		889,698	11,903	81,728	850	517,625	1,760	426,257	1,301	4,003	1,194
178	Uncollectibles expense		0	None	0	0	0	0	0	0	0	0	0	0
179	Depreciation expense		1,160,130		533,056	7,132	48,967	509	310,131	1,055	255,389	779	2,398	715
180	Regulatory Commission Expenses		94,727	PriD-Pt	43,525	582	3,998	42	25,323	86	20,853	64	196	58
181	General taxes / Other		27,263		12,527	168	1,151	12	7,288	25	6,002	18	56	17
182	Subtotal- Operating Costs to recover		3,218,441		1,478,806	19,785	135,844	1,413	860,367	2,925	708,501	2,162	6,654	1,985
183														
184	Target Return on Rate Base- After tax		1,298,277		596,531	7,981	54,798	570	347,061	1,180	285,800	872	2,684	801
185														
186	Income taxes to recover		366,960	28.27%	168,610	2,256	15,489	161	98,097	334	80,782	246	759	226
187														
188	Subtotal- Rev Req before GRT		4,883,678		2,243,947	30,021	206,130	2,144	1,305,525	4,439	1,075,082	3,280	10,097	3,012
189	GRT needed		291,139	6.27%	133,721	1,791	12,262	128	77,852	265	64,153	194	594	179
190	**TOTAL REVENUE REQUIREMEN**		5,174,817		2,377,668	31,813	218,392	2,272	1,383,377	4,704	1,139,235	3,474	10,690	3,190
191														
192	Revenue at Present rates		3,613,913		1,889,739	14,364	270,510	460	863,734	754	518,394	7,328	43,728	4,902
193	Revenue Excess (Deficiency)		(1,560,905)		(487,930)	(17,448)	52,118	(1,812)	(519,643)	(3,950)	(620,842)	3,853	33,037	1,712
194														

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Class Allocation- Secondary Demand

Line	Account	No.	Balance	Allocator	RS	RSAE	NRS	NRH	CS	CSH	IS	MSL	POL	EX
1	**I. ELECTRIC PLANT IN SERVICE**													
2	INTANGIBLE PLANT													
3	EDI Software	303	0	SecD-Lab	0	0	0	0	0	0	0	0	0	0
4	Total INTANGIBLE Plant		0		0	0	0	0	0	0	0	0	0	0
5														
6	**C. TRANSMISSION PLANT**													
7	Transmission Plant	361	0	None	0	0	0	0	0	0	0	0	0	0
8	Total TRANSMISSION Plant	350-359	0		0	0	0	0	0	0	0	0	0	0
9														
10	**D. DISTRIBUTION PLANT**													
11	Land & Land Rights	360	0	None	0	0	0	0	0	0	0	0	0	0
12	Structures and improvements	361	0	None	0	0	0	0	0	0	0	0	0	0
13	Station Equipment	362	0	None	0	0	0	0	0	0	0	0	0	0
14	Poles, Tower & Fixtures	364	917,711	NCP-Sec	541,125	7,240	49,708	517	314,826	1,070	0	791	2,435	0
15	OH Conductors & Devices	365	497,461	NCP-Sec	293,326	3,924	26,945	280	170,657	580	0	429	1,320	0
16	UG Conduits and Conductors	366	282,151	NCP-Sec	166,369	2,226	15,283	159	96,793	329	0	243	749	0
17	Line Transformers	368	755,617	NCP-Ltr	0	0	0	883	740,737	2,803	0	2,745	8,448	0
18	Services	369	0	None	0	0	0	0	0	0	0	0	0	0
19	Meters	370	0	None	0	0	0	0	0	0	0	0	0	0
20	Install. Customers' premises	371	0	None	0	0	0	0	0	0	0	0	0	0
21	Street Lighting & Signal	373	0	None	0	0	0	0	0	0	0	0	0	0
22	Total DISTRIBUTION Plant	360-373	2,452,940		1,000,820	13,390	91,936	1,839	1,323,013	4,783	0	4,208	12,952	0
23														
24	**E. GENERAL PLANT**													
25	General Plant	389	624,974	SecD-Lab	363,419	4,862	33,384	357	219,906	751	0	563	1,732	0
26	Communication Equip	398	7,535	SecD-Lab	4,382	59	403	4	2,651	9	0	7	21	0
27	Total GENERAL Plant	389-399	632,509		367,801	4,921	33,786	362	222,557	760	0	569	1,753	0
28														
29	**TOTAL UTILITY PLANT**		3,085,449		1,368,621	18,310	125,722	2,201	1,545,570	5,543	0	4,777	14,704	0
30														

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Line	Account	No.	Balance	Allocator	RS	RSAE	NRS	NRH	CS	CSH	IS	MSL	POL	EX
31	**II. DEPRECIATION RESERVE**													
32	Intangible Plant		0	None	0	0	0	0	0	0	0	0	0	0
33	Transmission Plant		0	None	0	0	0	0	0	0	0	0	0	0
34	Structures and improvements		0	None	0	0	0	0	0	0	0	0	0	0
35	Station Equipment		0	None	0	0	0	0	0	0	0	0	0	0
36	Poles, Towers and Fixtures		313,587	NCP-Sec	184,905	2,474	16,985	177	107,578	366	0	270	832	0
37	OH Conductors and Devices		169,806	NCP-Sec	100,126	1,340	9,198	96	58,253	198	0	146	451	0
38	UG Conduits and Conductors		211,840	NCP-Sec	124,910	1,671	11,474	119	72,673	247	0	183	562	0
39	Line Transformers		381,062	NCP-Ltr	0	0	0	445	373,558	1,414	0	1,384	4,261	0
40	Services		0	None	0	0	0	0	0	0	0	0	0	0
41	Meters		0	None	0	0	0	0	0	0	0	0	0	0
42	Install. Customers' premises		0	None	0	0	0	0	0	0	0	0	0	0
43	Street Lighting & Signal		0	None	0	0	0	0	0	0	0	0	0	0
44	General Plant		187,185	SecD-Lab	108,847	1,456	9,999	107	65,864	225	0	169	519	0
45	Total DEPRECIATION RESE	108	1,263,479		518,788	6,941	47,656	944	677,925	2,450	0	2,152	6,624	0
46														
47	**III. OTHER RATE BASE I**													
48	Cash Working Capital	131	30,650	SecD-OpExp	17,503	234	1,608	18	11,131	38	0	29	90	0
49	CWIP	131	0	SecD-Pt	0	0	0	0	0	0	0	0	0	0
50	Materials & Supplies	255	18,071	SecD-Pt	8,016	107	736	13	9,052	32	0	28	86	0
51	Customer Deposits		0	None	0	0	0	0	0	0	0	0	0	0
52	ADIT	154	(2,692)	SecD-Pt	(1,194)	(16)	(110)	(2)	(1,349)	(5)	0	(4)	(13)	0
53	Accrued Pension / OPEB	182	(1,790)	SecD-Lab	(1,041)	(14)	(96)	(1)	(630)	(2)	0	(2)	(5)	0
54	Total OTHER RATE BASE	131-283	44,238		23,283	311	2,139	28	18,204	64	0	51	158	0
55														
56	**TOTAL RATE BASE**		1,866,208		873,116	11,681	80,205	1,285	885,850	3,157	0	2,676	8,238	0
57														

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Line	Account	No.	Balance	Allocator	RS	RSAE	NRS	NRH	CS	CSH	IS	MSL	POL	EX
58	**I. OPERATING AND MAINTENANCE EXPENSES**													
59	**B. TRANSMISSION EXPENSE**													
60	Transmission Expense		0	None	0	0	0	0	0	0	0	0	0	0
61	Total TRANSMISSION Expe		0		0	0	0	0	0	0	0	0	0	0
62														
63	**C. DISTRIBUTION EXPENSE**													
64	Ops Supv & Engineering	580	0	SecD-Lab	0	0	0	0	0	0	0	0	0	0
65	Station Expenses	582	0	None	0	0	0	0	0	0	0	0	0	0
66	OH Line Expenses	583	440	NCP-Sec	259	3	24	0	151	1	0	0	1	0
67	Street Lighting Expenses	585	0	None	0	0	0	0	0	0	0	0	0	0
68	Meter Expenses	586	0	None	0	0	0	0	0	0	0	0	0	0
69	Customer Install. expense	587	0	None	0	0	0	0	0	0	0	0	0	0
70	Misc. Distribution Expenses	588	56,434	NCP-Sec	33,276	445	3,057	32	19,360	66	0	49	150	0
71	Rents	589	2,811	NCP-Sec	1,658	22	152	2	964	3	0	2	7	0
72	Maint Supv & Engineering	590	9,900	SecD-Lab	5,757	77	529	6	3,484	12	0	9	27	0
73	Maint of Station Equip	592	0	None	0	0	0	0	0	0	0	0	0	0
74	Maint of OH Lines	593	72,030	NCP-Sec	42,472	568	3,902	41	24,710	84	0	62	191	0
75	Maint of UG Lines	594	10,953	NCP-Sec	6,459	86	593	6	3,758	13	0	9	29	0
76	Maint of Line Transformers	595	1,810	NCP-Ltr	0	0	0	2	1,775	7	0	7	20	0
77	Maint of Lighting	596	0	None	0	0	0	0	0	0	0	0	0	0
78	Maint of Misc. Plant	599	6,386	NCP-Sec	3,766	50	346	4	2,191	7	0	6	17	0
79	Total DISTR. O&M EXP.	500-599	160,766		93,647	1,253	8,602	92	56,393	192	0	144	443	0
80	Distribution Expense		160,766		93,647	1,253	8,602	92	56,393	192	0	144	443	0
81	**D. CUSTOMER ACCOUNTS AND SERVICE**													
82	Supervision	901	0	None	0	0	0	0	0	0	0	0	0	0
83	Meter Reading Exp	902	0	None	0	0	0	0	0	0	0	0	0	0
84	Customer Records & Coll	903	0	None	0	0	0	0	0	0	0	0	0	0
85	Uncollectible Accounts	904	0	None	0	0	0	0	0	0	0	0	0	0
86	Subtotal - Cust. Accts. Exp.	901-905	0		0	0	0	0	0	0	0	0	0	0
87														
88	Customer Assistance	908	0	None	0	0	0	0	0	0	0	0	0	0
89	OPEN	916	0	None	0	0	0	0	0	0	0	0	0	0
90	Subtotal - Cust. Svce. & Info.	908-916	0		0	0	0	0	0	0	0	0	0	0
91	Total CUST. ACCT. & SERV	901-919	0		0	0	0	0	0	0	0	0	0	0
92														

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Line	Account	No.	Balance	Allocator	RS	RSAE	NRS	NRH	CS	CSH	IS	MSL	POL	EX
93	**E. ADMINISTRATIVE AND GENERAL**													
94	Admin. & Gen'l. Salaries	920	58,239	SecD-Lab	33,866	453	3,111	33	20,492	70	0	52	161	0
95	Office Supplies & Expenses	921	7,012	SecD-Lab	4,077	55	375	4	2,467	8	0	6	19	0
96	Outside Services Employed	923	11,487	SecD-LabPt	5,887	79	541	7	4,898	17	0	14	43	0
97	Property Insurance	924	4,269	SecD-Pt	1,894	25	174	3	2,139	8	0	7	20	0
98	Employee Pensions & Benefits	926	0	SecD-Lab	0	0	0	0	0	0	0	0	0	0
99	Regulatory Comm. Expense	928	0	SecD-Pt	0	0	0	0	0	0	0	0	0	0
100	Misc. General Expense	930	8,220	SecD-LabPt	4,213	56	387	5	3,505	12	0	10	31	0
101	Rents	931	141	SecD-Lab	82	1	8	0	49	0	0	0	0	0
102	Maint General Property	932	6,487	SecD-Pt	2,877	38	264	5	3,249	12	0	10	31	0
103	Total A&G Expense	920-932	95,854		52,896	708	4,859	58	36,800	127	0	100	307	0
104														
105	TOTAL OPERATING EXPENSES		256,620		146,543	1,961	13,462	149	93,192	320	0	244	750	0
106														
107	**II. DEPRECIATION EXPENSE**													
108	Intangible Plant		0	None	0	0	0	0	0	0	0	0	0	0
109	Station Equipment		0	None	0	0	0	0	0	0	0	0	0	0
110	Poles, Towers and Fixtures		31,322	NCP-Sec	18,469	247	1,697	18	10,745	37	0	27	83	0
111	OH Conductors and Devices		19,229	NCP-Sec	11,338	152	1,042	11	6,597	22	0	17	51	0
112	UG Conduits and Conductors		12,213	NCP-Sec	7,202	96	662	7	4,190	14	0	11	32	0
113	Line Transformers		26,168	NCP-Ltr	0	0	0	31	25,653	97	0	95	293	0
114	Services		0	None	0	0	0	0	0	0	0	0	0	0
115	Meters		0	None	0	0	0	0	0	0	0	0	0	0
116	Install. Customers' premises		0	None	0	0	0	0	0	0	0	0	0	0
117	Street Lighting & Signal		0	None	0	0	0	0	0	0	0	0	0	0
118	General Plant		33,285	SecD-Lab	19,355	259	1,778	19	11,712	40	0	30	92	0
119	Total DEPRECIATION Exp.	403	122,217		56,364	754	5,178	85	58,896	210	0	179	551	0
120														
121	**III. TAXES and OTHER**													
122	**A. GENERAL TAXES**													
123	Payroll related	408	0	SecD-Lab	0	0	0	0	0	0	0	0	0	0
124	PURTA, Real estate	408.16	3,011	SecD-Pt	1,336	18	123	2	1,508	5	0	5	14	0
125	Capital stock		0	RateBase	0	0	0	0	0	0	0	0	0	0
126	Other	408	58	SecD-Pt	26	0	2	0	29	0	0	0	0	0
127	Subtotal - General Taxes		3,069		1,361	18	125	2	1,537	6	0	5	15	0
128														
129	**B. GROSS RECEIPTS TAX**													
130	Gross Receipts tax		24,406	Dist_Rev	12,867	93	1,881	3	5,787	4	3,375	52	312	34
131	Subtotal- Gross Receipts tax		24,406		12,867	93	1,881	3	5,787	4	3,375	52	312	34
132														

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Line	Account	No.	Balance	Allocator	RS	RSAE	NRS	NRH	CS	CSH	IS	MSL	POL	EX
133	**B. FEDERAL / STATE INCOME TAXES**													
134	State Income Tax Expense		(3,810)	PreStaTax	(2,105)	(21)	(274)	(1)	(860)	(3)	(523)	(8)	(12)	(4)
135	Federal Income Tax Expense		(3,392)	PreFedTax	(1,874)	(19)	(244)	(1)	(765)	(3)	(466)	(7)	(11)	(3)
136	Subtotal - Fed / State Inc Tax	409-411	(7,202)		(3,979)	(40)	(517)	(3)	(1,625)	(5)	(989)	(15)	(22)	(7)
137	Total TAXES	408-411	20,274		10,249	72	1,488	2	5,699	4	2,386	42	304	27
138														
139	**TOTAL EXPENSES**		399,112		213,156	2,786	20,128	237	157,788	534	2,386	464	1,605	27
140														
141	**IV. OPERATING REVENUES at Present Rates**													
142	Distribution Revenue		415,680	Dist_Rev	219,138	1,591	32,029	44	98,555	67	57,479	881	5,311	585
143	Forfeited Discounts		0	None	0	0	0	0	0	0	0	0	0	0
144	Rent For Electric Property		16,815	NCP-Sec	9,915	133	911	9	5,769	20	0	14	45	0
145	Other Electric Revenues		1,494	Dist_Rev	788	6	115	0	354	0	207	3	19	2
146	Total REVENUES		433,989		229,841	1,730	33,055	54	104,678	87	57,685	898	5,374	587
147														
148	TOTAL EXPENSES		399,112		213,156	2,786	20,128	237	157,788	534	2,386	464	1,605	27
149	**V. NET INCOME at Present Rates**		34,878		16,684	(1,057)	12,927	(183)	(53,109)	(447)	55,299	434	3,769	560
150														
151	**SUMMARY REPORT**													
152	OPERATING REVENUES													
153	Utility Revenues	440-446	415,680		219,138	1,591	32,029	44	98,555	67	57,479	881	5,311	585
154	Other Operating Revenues	450-456	18,310		10,703	138	1,026	10	6,123	20	207	18	64	2
155	Total Operating Revenues		433,989		229,841	1,730	33,055	54	104,678	87	57,685	898	5,374	587
156														
157	OPERATING EXPENSES													
158	Distribution / Transmission	580-599	160,766		93,647	1,253	8,602	92	56,393	192	0	144	443	0
159	Customer Acctg & Service	901-919	0		0	0	0	0	0	0	0	0	0	0
160	Admin & General	920-932	95,854		52,896	708	4,859	58	36,800	127	0	100	307	0
161	Total Operating Expenses		256,620		146,543	1,961	13,462	149	93,192	320	0	244	750	0
162														
163	Depreciation Expense	403	122,217		56,364	754	5,178	85	58,896	210	0	179	551	0
164	Taxes Other Than Income	408	27,476		14,228	112	2,006	5	7,324	9	3,375	56	326	34
165	INCOME BEFORE INCOME		27,676		12,706	(1,097)	12,410	(185)	(54,734)	(453)	54,311	419	3,747	552
166	Income Taxes	409-411	(7,202)		(3,979)	(40)	(517)	(3)	(1,625)	(5)	(989)	(15)	(22)	(7)
167	**NET INCOME**		34,878		16,684	(1,057)	12,927	(183)	(53,109)	(447)	55,299	434	3,769	560
168														
169	**RATE BASE**		1,866,208		873,116	11,681	80,205	1,285	885,850	3,157	0	2,676	8,238	0
170	Return on Rate Base		1.87%											
171														

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Wellsboro Electric Company
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FPFTY Ending December 31, 2026
Class Allocation- Secondary Demand

Line	Account	No.	Balance	Allocator	RS	RSAE	NRS	NRH	CS	CSH	IS	MSL	POL	EX
172	**REVENUE REQUIREMENTS**													
173	Target Rate of Return		8.1800%		8.1800%	8.1800%	8.1800%	8.1800%	8.1800%	8.1800%	8.1800%	8.1800%	8.1800%	8.1800%
174														
175	Rate Base		1,866,208		873,116	11,681	80,205	1,285	885,850	3,157	0	2,676	8,238	0
176														
177	Operating expenses		256,620		146,543	1,961	13,462	149	93,192	320	0	244	750	0
178	Uncollectibles expense		0	None	0	0	0	0	0	0	0	0	0	0
179	Depreciation expense		122,217		56,364	754	5,178	85	58,896	210	0	179	551	0
180	Regulatory Commission Expenses		10,664	SecD-Pt	4,730	63	435	8	5,342	19	0	17	51	0
181	General taxes / Other		3,069		1,361	18	125	2	1,537	6	0	5	15	0
182	Subtotal- Operating Costs to recover		392,571		208,999	2,796	19,199	244	158,968	555	0	444	1,367	0
183														
184	Target Return on Rate Base- After tax		152,656		71,421	956	6,561	105	72,462	258	0	219	674	0
185														
186	Income taxes to recover		43,148	28.27%	20,187	270	1,854	30	20,482	73	0	62	190	0
187														
188	Subtotal- Rev Req before GRT		588,375		300,607	4,022	27,614	379	251,912	886	0	725	2,231	0
189	GRT needed		35,743	6.27%	18,177	243	1,667	23	15,411	54	(13)	44	136	(0)
190	**TOTAL REVENUE REQUIREMEN**		624,118		318,783	4,265	29,281	402	267,323	940	(13)	769	2,367	(0)
191														
192	Revenue at Present rates		433,989		229,841	1,730	33,055	54	104,678	87	57,685	898	5,374	587
193	Revenue Excess (Deficiency)		(190,129)		(88,943)	(2,535)	3,774	(348)	(162,644)	(854)	57,698	129	3,007	587
194														

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Wellsboro Electric Company
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Class Allocation- Secondary Customer

Line	Account	No.	Balance	Allocator	RS	RSAE	NRS	NRH	CS	CSH	IS	MSL	POL	EX
1	**I. ELECTRIC PLANT IN SERVICE**													
2	INTANGIBLE PLANT													
3	EDI Software	303	0	None	0	0	0	0	0	0	0	0	0	0
4	Total INTANGIBLE Plant		0		0	0	0	0	0	0	0	0	0	0
5														
6	**C. TRANSMISSION PLANT**													
7	Transmission Plant	361	0	None	0	0	0	0	0	0	0	0	0	0
8	Total TRANSMISSION Plant	350-359	0		0	0	0	0	0	0	0	0	0	0
9														
10	**D. DISTRIBUTION PLANT**													
11	Land & Land Rights	360	0	None	0	0	0	0	0	0	0	0	0	0
12	Structures and improvements	361	0	None	0	0	0	0	0	0	0	0	0	0
13	Station Equipment	362	0	None	0	0	0	0	0	0	0	0	0	0
14	Poles, Tower & Fixtures	364	1,565,277	Avg-Cust-Sec	1,240,737	6,981	222,918	241	93,191	241	0	0	0	966
15	OH Conductors & Devices	365	634,020	Avg-Cust-Sec	502,565	2,828	90,294	98	37,747	98	0	0	0	391
16	UG Conduits and Conductors	366	160,729	Avg-Cust-Sec	127,404	717	22,890	25	9,569	25	0	0	0	99
17	Line Transformers	368	2,609,971	Avg-Cust-Sec	2,068,828	11,641	371,698	403	155,389	403	0	0	0	1,610
18	Services	369	2,486,089	Services_Cost	1,843,433	10,372	331,202	359	289,474	750	10,499	0	0	0
19	Meters	370	0	None	0	0	0	0	0	0	0	0	0	0
20	Install. Customers' premises	371	0	None	0	0	0	0	0	0	0	0	0	0
21	Street Lighting & Signal	373	125,272	StLgt-Lamps	0	0	0	0	0	0	0	62,636	62,636	0
22	Total DISTRIBUTION Plant	360-373	7,581,357		5,782,967	32,539	1,039,002	1,125	585,370	1,517	10,499	62,636	62,636	3,066
23														
24	**E. GENERAL PLANT**													
25	General Plant	389	599,572	SecC-Lab	465,512	2,619	83,637	91	36,551	95	110	5,305	5,305	347
26	Communication Equip	398	7,229	SecC-Lab	5,613	32	1,008	1	441	1	1	64	64	4
27	Total GENERAL Plant	389-399	606,802		471,125	2,651	84,645	92	36,991	96	112	5,369	5,369	351
28														
29	**TOTAL UTILITY PLANT**		8,188,159		6,254,091	35,190	1,123,647	1,217	622,361	1,612	10,611	68,006	68,006	3,418
30														

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Line	Account	No.	Balance	Allocator	RS	RSAE	NRS	NRH	CS	CSH	IS	MSL	POL	EX
31	**II. DEPRECIATION RESERVE**													
32	Intangible Plant		0	None	0	0	0	0	0	0	0	0	0	0
33	Transmission Plant		0	None	0	0	0	0	0	0	0	0	0	0
34	Structures and improvements		0	None	0	0	0	0	0	0	0	0	0	0
35	Station Equipment		0	None	0	0	0	0	0	0	0	0	0	0
36	Poles, Towers and Fixtures		534,863	Avg-Cust-Sec	423,966	2,386	76,172	82	31,844	82	0	0	0	330
37	OH Conductors and Devices		216,420	Avg-Cust-Sec	171,549	965	30,821	33	12,885	33	0	0	0	134
38	UG Conduits and Conductors		120,675	Avg-Cust-Sec	95,655	538	17,186	19	7,185	19	0	0	0	74
39	Line Transformers		1,316,223	Avg-Cust-Sec	1,043,322	5,870	187,449	203	78,363	203	0	0	0	812
40	Services		1,472,321	Services_Cost	1,091,724	6,143	196,146	212	171,433	444	6,218	0	0	0
41	Meters		0	None	0	0	0	0	0	0	0	0	0	0
42	Install. Customers' premises		0	None	0	0	0	0	0	0	0	0	0	0
43	Street Lighting & Signal		(63,042)	StLgt-Lamps	0	0	0	0	0	0	0	(31,521)	(31,521)	0
44	General Plant		179,577	SecC-Lab	139,425	785	25,050	27	10,947	28	33	1,589	1,589	104
45	Total DEPRECIATION RESE	108	3,777,037		2,965,641	16,687	532,825	577	312,657	810	6,251	(29,932)	(29,932)	1,454
46														
47	**III. OTHER RATE BASE I**													
48	Cash Working Capital	131	34,218	SecC-OpExp	26,630	150	4,784	5	2,163	6	11	225	225	19
49	CWIP	131	0	SecC-Pt	0	0	0	0	0	0	0	0	0	0
50	Materials & Supplies	255	20,175	SecC-Pt	15,410	87	2,769	3	1,533	4	26	168	168	8
51	Customer Deposits		0	CustDeposits	0	0	0	0	0	0	0	0	0	0
52	ADIT	154	(7,145)	SecC-Pt	(5,457)	(31)	(980)	(1)	(543)	(1)	(9)	(59)	(59)	(3)
53	Accrued Pension / OPEB	182	(1,718)	SecC-Lab	(1,334)	(8)	(240)	(0)	(105)	(0)	(0)	(15)	(15)	(1)
54	Total OTHER RATE BASE	131-283	45,531		35,249	198	6,333	7	3,049	8	28	318	318	24
55														
56	**TOTAL RATE BASE**		4,456,653		3,323,699	18,702	597,156	647	312,753	810	4,388	98,256	98,256	1,987
57														

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Line	Account	No.	Balance	Allocator	RS	RSAE	NRS	NRH	CS	CSH	IS	MSL	POL	EX
58	**I. OPERATING AND MAINTENANCE EXPENSES**													
59	**B. TRANSMISSION EXPENSE**													
60	Transmission Expense		0	None	0	0	0	0	0	0	0	0	0	0
61	Total TRANSMISSION Expe		0		0	0	0	0	0	0	0	0	0	0
62														
63	**C. DISTRIBUTION EXPENSE**													
64	Ops Supv & Engineering	580	0	SecC-Lab	0	0	0	0	0	0	0	0	0	0
65	Station Expenses	582	0	None	0	0	0	0	0	0	0	0	0	0
66	OH Line Expenses	583	561	Avg-Cust-Sec	445	3	80	0	33	0	0	0	0	0
67	Street Lighting Expenses	585	267	StLgt-Lamps	0	0	0	0	0	0	0	134	134	0
68	Meter Expenses	586	0	None	0	0	0	0	0	0	0	0	0	0
69	Customer Install. expense	587	0	None	0	0	0	0	0	0	0	0	0	0
70	Misc. Distribution Expenses	588	24,685	Avg-Cust-Sec	19,567	110	3,516	4	1,470	4	0	0	0	15
71	Rents	589	7,460	Avg-Cust-Sec	5,913	33	1,062	1	444	1	0	0	0	5
72	Maint Supv & Engineering	590	9,498	SecC-Lab	7,374	41	1,325	1	579	2	2	84	84	6
73	Maint of Station Equip	592	0	None	0	0	0	0	0	0	0	0	0	0
74	Maint of OH Lines	593	91,803	Avg-Cust-Sec	72,769	409	13,074	14	5,466	14	0	0	0	57
75	Maint of UG Lines	594	6,240	Avg-Cust-Sec	4,946	28	889	1	371	1	0	0	0	4
76	Maint of Line Transformers	595	6,253	Avg-Cust-Sec	4,957	28	891	1	372	1	0	0	0	4
77	Maint of Lighting	596	942	StLgt-Lamps	0	0	0	0	0	0	0	471	471	0
78	Maint of Misc. Plant	599	16,948	SecC-Pt	12,945	73	2,326	3	1,288	3	22	141	141	7
79	Total DISTR. O&M EXP.	500-599	164,659		128,916	725	23,162	25	10,024	26	24	830	830	97
80	Distribution Expense		164,659		128,916	725	23,162	25	10,024	26	24	830	830	97
81	**D. CUSTOMER ACCOUNTS AND SERVICE**													
82	Supervision	901	0	None	0	0	0	0	0	0	0	0	0	0
83	Meter Reading Exp	902	0	None	0	0	0	0	0	0	0	0	0	0
84	Customer Records & Coll	903	0	None	0	0	0	0	0	0	0	0	0	0
85	Uncollectible Accounts	904	0	None	0	0	0	0	0	0	0	0	0	0
86	Subtotal - Cust. Accts. Exp.	901-905	0		0	0	0	0	0	0	0	0	0	0
87														
88	Customer Assistance	908	0	None	0	0	0	0	0	0	0	0	0	0
89	OPEN	916	0	None	0	0	0	0	0	0	0	0	0	0
90	Subtotal - Cust. Svce. & Info.	908-916	0		0	0	0	0	0	0	0	0	0	0
91	Total CUST. ACCT. & SERV	901-919	0		0	0	0	0	0	0	0	0	0	0
92														

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Wellsboro Electric Company
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Class Allocation- Secondary Customer

Line	Account	No.	Balance	Allocator	RS	RSAE	NRS	NRH	CS	CSH	IS	MSL	POL	EX
93	**E. ADMINISTRATIVE AND GENERAL**													
94	Admin. & Gen'l. Salaries	920	55,872	SecC-Lab	43,379	244	7,794	8	3,406	9	10	494	494	32
95	Office Supplies & Expenses	921	6,727	SecC-Lab	5,223	29	938	1	410	1	1	60	60	4
96	Outside Services Employed	923	17,814	SecC-LabPt	13,719	77	2,465	3	1,220	3	13	153	153	9
97	Property Insurance	924	11,330	SecC-Pt	8,654	49	1,555	2	861	2	15	94	94	5
98	Employee Pensions & Benefits	926	0	SecC-Lab	0	0	0	0	0	0	0	0	0	0
99	Regulatory Comm. Expense	928	0	SecC-Pt	0	0	0	0	0	0	0	0	0	0
100	Misc. General Expense	930	12,748	SecC-LabPt	9,817	55	1,764	2	873	2	9	109	109	6
101	Rents	931	135	SecC-Lab	105	1	19	0	8	0	0	1	1	0
102	Maint General Property	932	17,215	SecC-Pt	13,149	74	2,362	3	1,308	3	22	143	143	7
103	Total A&G Expense	920-932	121,840		94,045	529	16,897	18	8,087	21	71	1,054	1,054	63
104														
105	TOTAL OPERATING EXPENSES		286,499		222,961	1,255	40,059	43	18,111	47	95	1,884	1,884	161
106														
107	**II. DEPRECIATION EXPENSE**													
108	Intangible Plant		0	None	0	0	0	0	0	0	0	0	0	0
109	Station Equipment		0	None	0	0	0	0	0	0	0	0	0	0
110	Poles, Towers and Fixtures		53,423	Avg-Cust-Sec	42,347	238	7,608	8	3,181	8	0	0	0	33
111	OH Conductors and Devices		24,508	Avg-Cust-Sec	19,426	109	3,490	4	1,459	4	0	0	0	15
112	UG Conduits and Conductors		6,957	Avg-Cust-Sec	5,515	31	991	1	414	1	0	0	0	4
113	Line Transformers		90,387	Avg-Cust-Sec	71,646	403	12,872	14	5,381	14	0	0	0	56
114	Services		95,347	Services_Cost	70,700	398	12,702	14	11,102	29	403	0	0	0
115	Meters		0	None	0	0	0	0	0	0	0	0	0	0
116	Install. Customers' premises		0	None	0	0	0	0	0	0	0	0	0	0
117	Street Lighting & Signal		2,971	StLgt-Lamps	0	0	0	0	0	0	0	1,485	1,485	0
118	General Plant		31,932	SecC-Lab	24,793	140	4,454	5	1,947	5	6	283	283	18
119	Total DEPRECIATION Exp.	403	305,525		234,427	1,319	42,118	46	23,484	61	409	1,768	1,768	127
120														
121	**III. TAXES and OTHER**													
122	**A. GENERAL TAXES**													
123	Payroll related	408	0	SecC-Lab	0	0	0	0	0	0	0	0	0	0
124	PURTA, Real estate	408.16	7,991	SecC-Pt	6,103	34	1,097	1	607	2	10	66	66	3
125	Capital stock		0	RateBase	0	0	0	0	0	0	0	0	0	0
126	Other	408	154	SecC-Pt	118	1	21	0	12	0	0	1	1	0
127	Subtotal - General Taxes		8,145		6,221	35	1,118	1	619	2	11	68	68	3
128														
129	**B. GROSS RECEIPTS TAX**													
130	Gross Receipts tax		44,541	Dist_Rev	23,481	171	3,432	5	10,561	7	6,159	94	569	63
131	Subtotal- Gross Receipts tax		44,541		23,481	171	3,432	5	10,561	7	6,159	94	569	63
132														

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Wellsboro Electric Company
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Line	Account	No.	Balance	Allocator	RS	RSAE	NRS	NRH	CS	CSH	IS	MSL	POL	EX
133	**B. FEDERAL / STATE INCOME TAXES**													
134	State Income Tax Expense		(20,006)	PreStaTax	(11,052)	(111)	(1,437)	(7)	(4,514)	(15)	(2,747)	(41)	(62)	(20)
135	Federal Income Tax Expense		(17,807)	PreFedTax	(9,837)	(98)	(1,279)	(7)	(4,018)	(13)	(2,445)	(36)	(56)	(18)
136	Subtotal - Fed / State Inc Tax	409-411	(37,813)		(20,889)	(209)	(2,715)	(14)	(8,532)	(28)	(5,192)	(77)	(118)	(39)
137	Total TAXES	408-411	14,874		8,814	(4)	1,835	(8)	2,648	(20)	978	85	519	27
138														
139	**TOTAL EXPENSES**		606,898		466,201	2,570	84,012	81	44,242	88	1,481	3,737	4,171	315
140														
141	**IV. OPERATING REVENUES at Present Rates**													
142	Distribution Revenue		758,608	Dist_Rev	399,923	2,904	58,452	81	179,862	122	104,898	1,608	9,692	1,067
143	Forfeited Discounts		0	None	0	0	0	0	0	0	0	0	0	0
144	Rent For Electric Property		28,680	Avg-Cust-Sec	22,734	128	4,085	4	1,708	4	0	0	0	18
145	Other Electric Revenues		2,727	Dist_Rev	1,438	10	210	0	647	0	377	6	35	4
146	Total REVENUES		790,016		424,095	3,043	62,747	85	182,216	127	105,275	1,613	9,727	1,088
147														
148	TOTAL EXPENSES		606,898		466,201	2,570	84,012	81	44,242	88	1,481	3,737	4,171	315
149	**V. NET INCOME at Present Rates**		183,118		(42,106)	473	(21,265)	4	137,973	39	103,793	(2,123)	5,556	774
150														
151	**SUMMARY REPORT**													
152	OPERATING REVENUES													
153	Utility Revenues	440-446	758,608		399,923	2,904	58,452	81	179,862	122	104,898	1,608	9,692	1,067
154	Other Operating Revenues	450-456	31,408		24,172	138	4,295	5	2,354	5	377	6	35	22
155	Total Operating Revenues		790,016		424,095	3,043	62,747	85	182,216	127	105,275	1,613	9,727	1,088
156														
157	OPERATING EXPENSES													
158	Distribution / Transmission	580-599	164,659		128,916	725	23,162	25	10,024	26	24	830	830	97
159	Customer Acctg & Service	901-919	0		0	0	0	0	0	0	0	0	0	0
160	Admin & General	920-932	121,840		94,045	529	16,897	18	8,087	21	71	1,054	1,054	63
161	Total Operating Expenses		286,499		222,961	1,255	40,059	43	18,111	47	95	1,884	1,884	161
162														
163	Depreciation Expense	403	305,525		234,427	1,319	42,118	46	23,484	61	409	1,768	1,768	127
164	Taxes Other Than Income	408	52,686		29,702	206	4,550	6	11,180	9	6,170	162	637	66
165	INCOME BEFORE INCOME		145,306		(62,995)	263	(23,980)	(10)	129,442	11	98,602	(2,201)	5,438	735
166	Income Taxes	409-411	(37,813)		(20,889)	(209)	(2,715)	(14)	(8,532)	(28)	(5,192)	(77)	(118)	(39)
167	**NET INCOME**		183,118		(42,106)	473	(21,265)	4	137,973	39	103,793	(2,123)	5,556	774
168														
169	**RATE BASE**		4,456,653		3,323,699	18,702	597,156	647	312,753	810	4,388	98,256	98,256	1,987
170	Return on Rate Base		4.11%											
171														

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Wellsboro Electric Company
Embedded Cost of Service Study (ECOSS) (R)
FPFTY Ending December 31, 2026
Class Allocation- Secondary Customer

Line	Account	No.	Balance	Allocator	RS	RSAE	NRS	NRH	CS	CSH	IS	MSL	POL	EX
172	**REVENUE REQUIREMENTS**													
173	Target Rate of Return		8.1800%		8.1800%	8.1800%	8.1800%	8.1800%	8.1800%	8.1800%	8.1800%	8.1800%	8.1800%	8.1800%
174														
175	Rate Base		4,456,653		3,323,699	18,702	597,156	647	312,753	810	4,388	98,256	98,256	1,987
176														
177	Operating expenses		286,499		222,961	1,255	40,059	43	18,111	47	95	1,884	1,884	161
178	Uncollectibles expense		0	None	0	0	0	0	0	0	0	0	0	0
179	Depreciation expense		305,525		234,427	1,319	42,118	46	23,484	61	409	1,768	1,768	127
180	Regulatory Commission Expenses		28,300	SecC-Pt	21,615	122	3,884	4	2,151	6	37	235	235	12
181	General taxes / Other		8,145		6,221	35	1,118	1	619	2	11	68	68	3
182	Subtotal- Operating Costs to recover		628,469		485,224	2,730	87,178	94	44,365	115	551	3,955	3,955	302
183														
184	Target Return on Rate Base- After tax		364,554		271,879	1,530	48,847	53	25,583	66	359	8,037	8,037	163
185														
186	Income taxes to recover		103,042	28.27%	76,847	432	13,807	15	7,231	19	101	2,272	2,272	46
187														
188	Subtotal- Rev Req before GRT		1,096,065		833,949	4,692	149,832	162	77,179	200	1,011	14,264	14,264	511
189	GRT needed		66,753	6.27%	50,772	286	9,125	10	4,691	12	40	894	892	31
190	**TOTAL REVENUE REQUIREMEN**		1,162,818		884,722	4,978	158,957	172	81,871	212	1,051	15,158	15,156	542
191														
192	Revenue at Present rates		790,016		424,095	3,043	62,747	85	182,216	127	105,275	1,613	9,727	1,088
193	Revenue Excess (Deficiency)		(372,802)		(460,627)	(1,935)	(96,211)	(87)	100,345	(85)	104,224	(13,544)	(5,429)	547
194														

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Wellsboro Electric Company
Embedded Cost of Service Study (ECOSS) (R)
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Class Allocation- Billing Customer

Line	Account	No.	Balance	Allocator	RS	RSAE	NRS	NRH	CS	CSH	IS	MSL	POL	EX
1	**I. ELECTRIC PLANT IN SERVICE**													
2	INTANGIBLE PLANT													
3	EDI Software	303	284,588	Avg-Cust	225,096	1,267	40,442	44	16,907	44	613	0	0	175
4	Total INTANGIBLE Plant		284,588		225,096	1,267	40,442	44	16,907	44	613	0	0	175
5														
6	**C. TRANSMISSION PLANT**													
7	Transmission Plant	361	0	None	0	0	0	0	0	0	0	0	0	0
8	Total TRANSMISSION Plant	350-359	0		0	0	0	0	0	0	0	0	0	0
9														
10	**D. DISTRIBUTION PLANT**													
11	Land & Land Rights	360	0	None	0	0	0	0	0	0	0	0	0	0
12	Structures and improvements	361	0	None	0	0	0	0	0	0	0	0	0	0
13	Station Equipment	362	0	None	0	0	0	0	0	0	0	0	0	0
14	Poles, Tower & Fixtures	364	0	None	0	0	0	0	0	0	0	0	0	0
15	OH Conductors & Devices	365	0	None	0	0	0	0	0	0	0	0	0	0
16	UG Conduits and Conductors	366	0	None	0	0	0	0	0	0	0	0	0	0
17	Line Transformers	368	0	None	0	0	0	0	0	0	0	0	0	0
18	Services	369	0	None	0	0	0	0	0	0	0	0	0	0
19	Meters	370	1,041,481	Meter_Cost	626,404	3,525	112,544	122	225,632	585	56,521	0	0	16,149
20	Install. Customers' premises	371	519,618	Avg-Cust	410,994	2,313	73,842	80	30,870	80	1,120	0	0	320
21	Street Lighting & Signal	373	0	StLgt-Lamps	0	0	0	0	0	0	0	0	0	0
22	Total DISTRIBUTION Plant	360-373	1,561,098		1,037,398	5,837	186,385	202	256,502	665	57,641	0	0	16,469
23														
24	**E. GENERAL PLANT**													
25	General Plant	389	4,090,167	Bill-Lab	3,158,639	17,773	567,500	615	306,466	794	29,852	0	0	8,529
26	Communication Equip	398	49,315	Bill-Lab	38,084	214	6,842	7	3,695	10	360	0	0	103
27	Total GENERAL Plant	389-399	4,139,482		3,196,723	17,987	574,342	622	310,161	804	30,212	0	0	8,632
28														
29	**TOTAL UTILITY PLANT**		5,985,168		4,459,218	25,091	801,170	868	583,569	1,512	88,465	0	0	25,276
30														

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Embedded Cost of Service Study (ECOSS) (R)
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Line	Account	No.	Balance	Allocator	RS	RSAE	NRS	NRH	CS	CSH	IS	MSL	POL	EX
31	**II. DEPRECIATION RESERVE**													
32	Intangible Plant		284,588	Avg-Cust	225,096	1,267	40,442	44	16,907	44	613	0	0	175
33	Transmission Plant		0	None	0	0	0	0	0	0	0	0	0	0
34	Structures and improvements		0	None	0	0	0	0	0	0	0	0	0	0
35	Station Equipment		0	None	0	0	0	0	0	0	0	0	0	0
36	Poles, Towers and Fixtures		0	None	0	0	0	0	0	0	0	0	0	0
37	OH Conductors and Devices		0	None	0	0	0	0	0	0	0	0	0	0
38	UG Conduits and Conductors		0	None	0	0	0	0	0	0	0	0	0	0
39	Line Transformers		0	None	0	0	0	0	0	0	0	0	0	0
40	Services		0	None	0	0	0	0	0	0	0	0	0	0
41	Meters		787,559	Meter_Cost	473,682	2,665	85,104	92	170,621	442	42,741	0	0	12,212
42	Install. Customers' premises		115,728	Avg-Cust	91,536	515	16,446	18	6,875	18	249	0	0	71
43	Street Lighting & Signal		0	StLgt-Lamps	0	0	0	0	0	0	0	0	0	0
44	General Plant		1,225,037	Bill-Lab	946,037	5,323	169,971	184	91,789	238	8,941	0	0	2,555
45	Total DEPRECIATION RESE	108	2,412,913		1,736,351	9,770	311,963	338	286,192	741	52,544	0	0	15,013
46														
47	**III. OTHER RATE BASE I**													
48	Cash Working Capital	131	216,579	Bill-OpExp	164,474	974	28,714	36	18,067	50	3,735	79	102	348
49	CWIP	131	0	Bill-Pt	0	0	0	0	0	0	0	0	0	0
50	Materials & Supplies	255	127,695	Bill-Pt	94,846	534	17,041	18	12,693	33	1,968	0	0	562
51	Customer Deposits		(120,033)	CustDeposits	(69,214)	(508)	(6,737)	(18)	(27,130)	(13)	(15,543)	0	(714)	(156)
52	ADIT	154	(4,974)	Bill-Pt	(3,695)	(21)	(664)	(1)	(494)	(1)	(77)	0	0	(22)
53	Accrued Pension / OPEB	182	(11,717)	Bill-Lab	(9,049)	(51)	(1,626)	(2)	(878)	(2)	(86)	0	0	(24)
54	Total OTHER RATE BASE	131-283	207,549		177,363	927	36,728	34	2,257	65	(10,001)	79	(612)	708
55														
56	**TOTAL RATE BASE**		3,779,805		2,900,229	16,248	525,935	564	299,635	836	25,920	79	(612)	10,971
57														

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FPFTY Ending December 31, 2026
Class Allocation- Billing Customer

Line	Account	No.	Balance	Allocator	RS	RSAE	NRS	NRH	CS	CSH	IS	MSL	POL	EX
58	**I. OPERATING AND MAINTENANCE EXPENSES**													
59	**B. TRANSMISSION EXPENSE**													
60	Transmission Expense		0	None	0	0	0	0	0	0	0	0	0	0
61	Total TRANSMISSION Expe		0		0	0	0	0	0	0	0	0	0	0
62														
63	**C. DISTRIBUTION EXPENSE**													
64	Ops Supv & Engineering	580	0	Bill-DxLab	0	0	0	0	0	0	0	0	0	0
65	Station Expenses	582	0	None	0	0	0	0	0	0	0	0	0	0
66	OH Line Expenses	583	0	None	0	0	0	0	0	0	0	0	0	0
67	Street Lighting Expenses	585	0	StLgt-Lamps	0	0	0	0	0	0	0	0	0	0
68	Meter Expenses	586	39,903	Meter_Cost	24,000	135	4,312	5	8,645	22	2,166	0	0	619
69	Customer Install. expense	587	267	Avg-Cust	212	1	38	0	16	0	1	0	0	0
70	Misc. Distribution Expenses	588	0	Avg-Cust	0	0	0	0	0	0	0	0	0	0
71	Rents	589	1,598	Bill-Pt	1,187	7	213	0	159	0	25	0	0	7
72	Maint Supv & Engineering	590	459	Bill-DxLab	281	2	50	0	96	0	24	0	0	7
73	Maint of Station Equip	592	0	None	0	0	0	0	0	0	0	0	0	0
74	Maint of OH Lines	593	0	None	0	0	0	0	0	0	0	0	0	0
75	Maint of UG Lines	594	0	None	0	0	0	0	0	0	0	0	0	0
76	Maint of Line Transformers	595	0	None	0	0	0	0	0	0	0	0	0	0
77	Maint of Lighting	596	0	StLgt-Lamps	0	0	0	0	0	0	0	0	0	0
78	Maint of Misc. Plant	599	3,630	Bill-Pt	2,696	15	484	1	361	1	56	0	0	16
79	Total DISTR. O&M EXP.	500-599	45,858		28,375	160	5,098	6	9,277	24	2,270	0	0	649
80	Distribution Expense		45,858		28,375	160	5,098	6	9,277	24	2,270	0	0	649
81	**D. CUSTOMER ACCOUNTS AND SERVICE**													
82	Supervision	901	0	Avg-Cust	0	0	0	0	0	0	0	0	0	0
83	Meter Reading Exp	902	16,544	Meter_Cost	9,950	56	1,788	2	3,584	9	898	0	0	257
84	Customer Records & Coll	903	1,047,510	Avg-Cust	828,534	4,662	148,859	161	62,231	161	2,257	0	0	645
85	Uncollectible Accounts	904	20,000	Write-Offs	17,398	128	331	1	1,334	1	764	0	35	8
86	Subtotal - Cust. Accts. Exp.	901-905	1,084,054		855,882	4,846	150,978	164	67,149	171	3,919	0	35	909
87														
88	Customer Assistance	908	9,737	Avg-Cust	7,702	43	1,384	1	578	1	21	0	0	6
89	OPEN	916	0	None	0	0	0	0	0	0	0	0	0	0
90	Subtotal - Cust. Svce. & Info.	908-916	9,737		7,702	43	1,384	1	578	1	21	0	0	6
91	Total CUST. ACCT. & SERV	901-919	1,093,791		863,584	4,889	152,362	166	67,728	173	3,940	0	35	915
92														

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Wellsboro Electric Company
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Line	Account	No.	Balance	Allocator	RS	RSAE	NRS	NRH	CS	CSH	IS	MSL	POL	EX
93	**E. ADMINISTRATIVE AND GENERAL**													
94	Admin. & Gen'l. Salaries	920	381,146	Bill-Lab	294,341	1,656	52,883	57	28,558	74	2,782	0	0	795
95	Office Supplies & Expenses	921	45,889	Bill-Lab	35,438	199	6,367	7	3,438	9	335	0	0	96
96	Outside Services Employed	923	42,241	Bill-LabPt	31,998	180	5,749	6	3,682	10	480	0	0	137
97	Property Insurance	924	7,888	Bill-Pt	5,859	33	1,053	1	784	2	122	0	0	35
98	Employee Pensions & Benefits	926	0	Bill-Lab	0	0	0	0	0	0	0	0	0	0
99	Regulatory Comm. Expense	928	153,393	RateBase	84,979	852	11,062	56	33,904	114	20,813	659	819	134
100	Misc. General Expense	930	30,228	Bill-LabPt	22,898	129	4,114	4	2,635	7	343	0	0	98
101	Rents	931	920	Bill-Lab	711	4	128	0	69	0	7	0	0	2
102	Maint General Property	932	11,985	Bill-Pt	8,902	50	1,599	2	1,191	3	185	0	0	53
103	Total A&G Expense	920-932	673,690		485,125	3,103	82,955	134	74,262	218	25,065	659	819	1,349
104														
105	TOTAL OPERATING EXPENSES		1,813,339		1,377,084	8,152	240,415	305	151,266	415	31,276	659	854	2,913
106														
107	**II. DEPRECIATION EXPENSE**													
108	Intangible Plant		0	Avg-Cust	0	0	0	0	0	0	0	0	0	0
109	Station Equipment		0	None	0	0	0	0	0	0	0	0	0	0
110	Poles, Towers and Fixtures		0	None	0	0	0	0	0	0	0	0	0	0
111	OH Conductors and Devices		0	None	0	0	0	0	0	0	0	0	0	0
112	UG Conduits and Conductors		0	None	0	0	0	0	0	0	0	0	0	0
113	Line Transformers		0	None	0	0	0	0	0	0	0	0	0	0
114	Services		0	None	0	0	0	0	0	0	0	0	0	0
115	Meters		79,809	Meter_Cost	48,002	270	8,624	9	17,290	45	4,331	0	0	1,237
116	Install. Customers' premises		53,884	Avg-Cust	42,620	240	7,657	8	3,201	8	116	0	0	33
117	Street Lighting & Signal		0	StLgt-Lamps	0	0	0	0	0	0	0	0	0	0
118	General Plant		217,837	Bill-Lab	168,225	947	30,224	33	16,322	42	1,590	0	0	454
119	Total DEPRECIATION Exp.	403	351,530		258,847	1,456	46,506	50	36,813	95	6,037	0	0	1,725
120														
121	**III. TAXES and OTHER**													
122	**A. GENERAL TAXES**													
123	Payroll related	408	0	None	0	0	0	0	0	0	0	0	0	0
124	PURTA, Real estate	408.16	5,563	Bill-Pt	4,132	23	742	1	553	1	86	0	0	24
125	Capital stock		0	RateBase	0	0	0	0	0	0	0	0	0	0
126	Other	408	108	Bill-Pt	80	0	14	0	11	0	2	0	0	0
127	Subtotal - General Taxes		5,670		4,212	24	757	1	564	1	87	0	0	25
128														
129	**B. GROSS RECEIPTS TAX**													
130	Gross Receipts tax		108,747	Dist_Rev	57,329	416	8,379	12	25,783	18	15,037	230	1,389	153
131	Subtotal- Gross Receipts tax		108,747		57,329	416	8,379	12	25,783	18	15,037	230	1,389	153
132														

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Line	Account	No.	Balance	Allocator	RS	RSAE	NRS	NRH	CS	CSH	IS	MSL	POL	EX
133	**B. FEDERAL / STATE INCOME TAXES**													
134	State Income Tax Expense		0	PreStaTax	0	0	0	0	0	0	0	0	0	0
135	Federal Income Tax Expense		0	PreFedTax	0	0	0	0	0	0	0	0	0	0
136	Subtotal - Fed / State Inc Tax	409-411	0		0	0	0	0	0	0	0	0	0	0
137	Total TAXES	408-411	114,418		61,541	440	9,136	12	26,347	19	15,125	230	1,389	178
138														
139	**TOTAL EXPENSES**		2,279,288		1,697,472	10,048	296,057	368	214,427	529	52,438	890	2,244	4,816
140														
141	**IV. OPERATING REVENUES at Present Rates**													
142	Distribution Revenue		1,821,174	Dist_Rev	960,087	6,972	140,325	193	431,790	294	251,826	3,859	23,267	2,561
143	Forfeited Discounts		30,962	Write-Offs	26,934	198	513	1	2,066	1	1,183	0	54	12
144	Rent For Electric Property		0	None	0	0	0	0	0	0	0	0	0	0
145	Other Electric Revenues		6,548	Dist_Rev	3,452	25	505	1	1,552	1	905	14	84	9
146	Total REVENUES		1,858,684		990,473	7,195	141,342	195	435,408	296	253,914	3,873	23,405	2,582
147														
148	TOTAL EXPENSES		2,279,288		1,697,472	10,048	296,057	368	214,427	529	52,438	890	2,244	4,816
149	**V. NET INCOME at Present Rates**		(420,604)		(706,999)	(2,853)	(154,715)	(172)	220,981	(233)	201,477	2,983	21,161	(2,234)
150														
151	**SUMMARY REPORT**													
152	OPERATING REVENUES													
153	Utility Revenues	440-446	1,852,136		987,021	7,170	140,838	195	433,856	295	253,009	3,859	23,321	2,573
154	Other Operating Revenues	450-456	6,548		3,452	25	505	1	1,552	1	905	14	84	9
155	Total Operating Revenues		1,858,684		990,473	7,195	141,342	195	435,408	296	253,914	3,873	23,405	2,582
156														
157	OPERATING EXPENSES													
158	Distribution / Transmission	580-599	45,858		28,375	160	5,098	6	9,277	24	2,270	0	0	649
159	Customer Acctg & Service	901-919	1,093,791		863,584	4,889	152,362	166	67,728	173	3,940	0	35	915
160	Admin & General	920-932	673,690		485,125	3,103	82,955	134	74,262	218	25,065	659	819	1,349
161	Total Operating Expenses		1,813,339		1,377,084	8,152	240,415	305	151,266	415	31,276	659	854	2,913
162														
163	Depreciation Expense	403	351,530		258,847	1,456	46,506	50	36,813	95	6,037	0	0	1,725
164	Taxes Other Than Income	408	114,418		61,541	440	9,136	12	26,347	19	15,125	230	1,389	178
165	INCOME BEFORE INCOME		(420,604)		(706,999)	(2,853)	(154,715)	(172)	220,981	(233)	201,477	2,983	21,161	(2,234)
166	Income Taxes	409-411	0		0	0	0	0	0	0	0	0	0	0
167	**NET INCOME**		(420,604)		(706,999)	(2,853)	(154,715)	(172)	220,981	(233)	201,477	2,983	21,161	(2,234)
168														
169	**RATE BASE**		3,779,805		2,900,229	16,248	525,935	564	299,635	836	25,920	79	(612)	10,971
170	Return on Rate Base		-11.13%											
171														

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Class Allocation- Billing Customer

Line	Account	No.	Balance	Allocator	RS	RSAE	NRS	NRH	CS	CSH	IS	MSL	POL	EX
172	**REVENUE REQUIREMENTS**													
173	Target Rate of Return		8.1800%		8.1800%	8.1800%	8.1800%	8.1800%	8.1800%	8.1800%	8.1800%	8.1800%	8.1800%	8.1800%
174														
175	Rate Base		3,779,805		2,900,229	16,248	525,935	564	299,635	836	25,920	79	(612)	10,971
176														
177	Operating expenses		1,639,947		1,274,707	7,172	229,021	248	116,028	301	9,699	0	0	2,771
178	Uncollectibles expense		20,000	Write-Offs	17,398	128	331	1	1,334	1	764	0	35	8
179	Depreciation expense		351,530		258,847	1,456	46,506	50	36,813	95	6,037	0	0	1,725
180	Regulatory Commission Expenses		19,702	Bill-Pt	14,634	82	2,629	3	1,958	5	304	0	0	87
181	General taxes / Other		5,670		4,212	24	757	1	564	1	87	0	0	25
182	Subtotal- Operating Costs to recover		2,036,850		1,569,797	8,863	279,245	303	156,698	403	16,891	0	35	4,615
183														
184	Target Return on Rate Base- After tax		309,188		237,239	1,329	43,021	46	24,510	68	2,120	6	(50)	897
185														
186	Income taxes to recover		87,392	28.27%	67,056	376	12,160	13	6,928	19	599	2	(14)	254
187														
188	Subtotal- Rev Req before GRT		2,433,430		1,874,092	10,567	334,426	362	188,135	491	19,611	8	(29)	5,767
189	GRT needed		150,222	6.27%	115,599	649	20,904	23	11,569	31	1,099	(0)	(10)	360
190	**TOTAL REVENUE REQUIREMEN**		2,583,653		1,989,690	11,216	355,331	385	199,705	522	20,710	8	(40)	6,127
191														
192	Revenue at Present rates		1,858,684		990,473	7,195	141,342	195	435,408	296	253,914	3,873	23,405	2,582
193	Revenue Excess (Deficiency)		(724,969)		(999,218)	(4,021)	(213,988)	(189)	235,703	(225)	233,205	3,865	23,445	(3,545)
194														

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Wellsboro Electric Company
Embedded Cost of Service Study (ECOSS) (R)
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Line	Account	No.	Balance	Function Allocator	Classify Secondary	Class Allocation PrimDem	SecnDem	SecnCus	BillCus ×
1	**I. ELECTRIC PLANT IN SERVICE**								
2	INTANGIBLE PLANT								
3	EDI Software	303	284,588	Bill	-	-	-	-	Avg-Cust
4	Total INTANGIBLE Plant		284,588						
5									
6	**C. TRANSMISSION PLANT**								
7	Transmission Plant	361	0	-	-	-	-	-	-
8	Total TRANSMISSION Plant	350-359	0						
9									
10	**D. DISTRIBUTION PLANT**								
11	Land & Land Rights	360	178,334	Prim	-	NCP-Prim	-	-	-
12	Structures and improvements	361	0	-	-	-	-	-	-
13	Station Equipment	362	3,992,800	Prim	-	NCP-Prim	-	-	-
14	Poles, Tower & Fixtures	364	14,933,172	OH_Cond	PTF-Sec-Z	NCP-Prim	NCP-Sec	Avg-Cust-Sec	-
15	OH Conductors & Devices	365	6,804,947	OH_Cond	OH-Sec-Z	NCP-Prim	NCP-Sec	Avg-Cust-Sec	-
16	UG Conduits and Conductors	366	1,038,449	UG_Cond	UG-Sec-Z	NCP-Prim	NCP-Sec	Avg-Cust-Sec	-
17	Line Transformers	368	3,365,587	Trans	Trans-Min	-	NCP-Ltr	Avg-Cust-Sec	-
18	Services	369	2,486,089	Sec	Customer	-	-	Services_Cost	-
19	Meters	370	1,041,481	Bill	-	-	-	-	Meter_Cost
20	Install. Customers' premises	371	519,618	Bill	-	-	-	-	Avg-Cust
21	Street Lighting & Signal	373	125,272	Sec	Customer	-	-	StLgt-Lamps	-
22	Total DISTRIBUTION Plant	360-373	34,485,748						
23									
24	**E. GENERAL PLANT**								
25	General Plant	389	9,778,618	Labor	Sec-Lab	PriD-Lab	SecD-Lab	SecC-Lab	Bill-Lab
26	Communication Equip	398	117,901	Labor	Sec-Lab	PriD-Lab	SecD-Lab	SecC-Lab	Bill-Lab
27	Total GENERAL Plant	389-399	9,896,519						
28									
29	**TOTAL UTILITY PLANT**		44,666,856						
30									

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Line	Account	No.	Balance	Function	Classify	Class Allocation			
				Allocator	Secondary	PrimDem	SecnDem	SecnCus	BillCus ×
31	**II. DEPRECIATION RESERVE**								
32	Intangible Plant		284,588	IntanPt	-	-	-	-	Avg-Cust
33	Transmission Plant		0	-	-	-	-	-	-
34	Structures and improvements		0	-	-	-	-	-	-
35	Station Equipment		3,892,596	Prim	-	NCP-Prim	-	-	-
36	Poles, Towers and Fixtures		5,102,743	OH_Cond	PTF-Sec-Z	NCP-Prim	NCP-Sec	Avg-Cust-Sec	-
37	OH Conductors and Devices		2,322,844	OH_Cond	OH-Sec-Z	NCP-Prim	NCP-Sec	Avg-Cust-Sec	-
38	UG Conduits and Conductors		779,669	UG_Cond	UG-Sec-Z	NCP-Prim	NCP-Sec	Avg-Cust-Sec	-
39	Line Transformers		1,697,284	Trans	Trans-Min	-	NCP-Ltr	Avg-Cust-Sec	-
40	Services		1,472,321	Sec	Customer	-	-	Services_Cost	-
41	Meters		787,559	Bill	-	-	-	-	Meter_Cost
42	Install. Customers' premises		115,728	Bill	-	-	-	-	Avg-Cust
43	Street Lighting & Signal		(63,042)	Sec	Customer	-	-	StLgt-Lamps	-
44	General Plant		2,928,774	GenPtxL	Sec-GenPt	PriD-Lab	SecD-Lab	SecC-Lab	Bill-Lab
45	Total DEPRECIATION RESE	108	9,279,927						
46									
47	**III. OTHER RATE BASE ITEMS**								
48	Cash Working Capital	131	512,714	OpExp_Dist	Sec-OpExp	PriD-OpExp	SecD-OpExp	SecC-OpExp	Bill-OpExp
49	CWIP	131	0	-	-	-	-	-	-
50	Materials & Supplies	255	302,296	OpExp_Dist	Sec-OpExp	PriD-Pt	SecD-Pt	SecC-Pt	Bill-Pt
51	Customer Deposits		(120,033)	Bill	-	-	-	-	CustDeposits
52	ADIT	154	(38,728)	Plant	Sec-Pt	PriD-Pt	SecD-Pt	SecC-Pt	Bill-Pt
53	Accrued Pension / OPEB	182	(28,013)	Labor	Sec-Lab	PriD-Lab	SecD-Lab	SecC-Lab	Bill-Lab
54	Total OTHER RATE BASE	131-283	628,236						
55									
56	**TOTAL RATE BASE**		36,015,165						
57									

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Line	Account	No.	Balance	Function	Classify	Class Allocation			
				Allocator	Secondary	PrimDem	SecnDem	SecnCus	BillCus ×
58	**I. OPERATING AND MAINTENANCE EXPENSES**								
59	B. TRANSMISSION EXPENSE								
60	Transmission Expense								
61	Total TRANSMISSION Expense								
62									
63	**C. DISTRIBUTION EXPENSE**								
64	Ops Supv & Engineering	580	0	-	-	-	-	-	-
65	Station Expenses	582	0	-	-	-	-	-	-
66	OH Line Expenses	583	6,020	OH_Cond	OH-Sec-Z	NCP-Prim	NCP-Sec	Avg-Cust-Sec	-
67	Street Lighting Expenses	585	267	Sec	Customer	-	-	StLgt-Lamps	-
68	Meter Expenses	586	39,903	Bill	-	-	-	-	Meter_Cost
69	Customer Install. expense	587	267	Bill	-	-	-	-	Avg-Cust
70	Misc. Distribution Expenses	588	285,688	OH_UG	Sec-OH_UG	NCP-Prim	NCP-Sec	Avg-Cust-Sec	-
71	Rents	589	35,300	DistPt	Sec-Pt	NCP-Prim	NCP-Sec	Avg-Cust-Sec	Bill-Pt
72	Maint Supv & Engineering	590	101,784	D-Labor-Mnt	Sec-Lab	PriD-Lab	SecD-Lab	SecC-Lab	Bill-DxLab
73	Maint of Station Equip	592	18,557	Prim	-	NCP-Prim	-	-	-
74	Maint of OH Lines	593	985,327	OH_Cond	OH-Sec-Z	NCP-Prim	NCP-Sec	Avg-Cust-Sec	-
75	Maint of UG Lines	594	40,313	UG_Cond	UG-Sec-Z	NCP-Prim	NCP-Sec	Avg-Cust-Sec	-
76	Maint of Line Transformers	595	8,064	Trans	Trans-Min	-	NCP-Ltr	Avg-Cust-Sec	-
77	Maint of Lighting	596	942	Sec	Customer	-	-	StLgt-Lamps	-
78	Maint of Misc. Plant	599	80,194	DistPt	Sec-Pt	NCP-Prim	NCP-Sec	SecC-Pt	Bill-Pt
79	Total DISTR. O&M EXP.	500-599	1,602,629						
80	Distribution Expense								
81	**D. CUSTOMER ACCOUNTS AND SERVICE**								
82	Supervision	901	0	-	-	-	-	-	-
83	Meter Reading Exp	902	16,544	Bill	-	-	-	-	Meter_Cost
84	Customer Records & Coll	903	1,047,510	Bill	-	-	-	-	Avg-Cust
85	Uncollectible Accounts	904	20,000	Bill	-	-	-	-	Write-Offs
86	Subtotal - Cust. Accts. Exp.	901-905	1,084,054						
87									
88	Customer Assistance	908	9,737	Bill	-	-	-	-	Avg-Cust
89	OPEN	916	0	-	-	-	-	-	-
90	Subtotal - Cust. Svce. & Info.	908-916	9,737						
91	Total CUST. ACCT. & SERV	901-919	1,093,791						
92									

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Wellsboro Electric Company
Embedded Cost of Service Study (ECOSS) (R)
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Line	Account	No.	Balance	Function	Classify	Class Allocation			
				Allocator	Secondary	PrimDem	SecnDem	SecnCus	BillCus ×
93	**E. ADMINISTRATIVE AND GENERAL**								
94	Admin. & Gen'l. Salaries	920	911,229	Labor	Sec-Lab	PriD-Lab	SecD-Lab	SecC-Lab	Bill-Lab
95	Office Supplies & Expenses	921	109,710	Labor	Sec-Lab	PriD-Lab	SecD-Lab	SecC-Lab	Bill-Lab
96	Outside Services Employed	923	154,525	Labor_Pt	Sec-LabPt	PriD-LabPt	SecD-LabPt	SecC-LabPt	Bill-LabPt
97	Property Insurance	924	61,410	Plant	Sec-Pt	PriD-Pt	SecD-Pt	SecC-Pt	Bill-Pt
98	Employee Pensions & Benefits	926	0	-	-	-	-	-	-
99	Regulatory Comm. Expense	928	153,393	Bill	-	-	-	-	RateBase
100	Misc. General Expense	930	110,581	Labor_Pt	Sec-LabPt	PriD-LabPt	SecD-LabPt	SecC-LabPt	Bill-LabPt
101	Rents	931	2,200	Labor	Sec-Lab	PriD-Lab	SecD-Lab	SecC-Lab	Bill-Lab
102	Maint General Property	932	93,311	Plant	Sec-Pt	PriD-Pt	SecD-Pt	SecC-Pt	Bill-Pt
103	Total A&G Expense	920-932	1,596,359						
104									
105	TOTAL OPERATING EXPEI		4,292,779						
106									
107	**II. DEPRECIATION EXPENSE**								
108	Intangible Plant		0	-	-	-	-	-	-
109	Station Equipment		252,375	Prim	-	NCP-Prim	-	-	-
110	Poles, Towers and Fixtures		509,675	OH_Cond	PTF-Sec-Z	NCP-Prim	NCP-Sec	Avg-Cust-Sec	-
111	OH Conductors and Devices		263,041	OH_Cond	OH-Sec-Z	NCP-Prim	NCP-Sec	Avg-Cust-Sec	-
112	UG Conduits and Conductors		44,951	UG_Cond	UG-Sec-Z	NCP-Prim	NCP-Sec	Avg-Cust-Sec	-
113	Line Transformers		116,555	Trans	Trans-Min	-	NCP-Ltr	Avg-Cust-Sec	-
114	Services		95,347	Sec	Customer	-	-	Services_Cost	-
115	Meters		79,809	Bill	-	-	-	-	Meter_Cost
116	Install. Customers' premises		53,884	Bill	-	-	-	-	Avg-Cust
117	Street Lighting & Signal		2,971	Sec	Customer	-	-	StLgt-Lamps	-
118	General Plant		520,797	GenPtxL	Sec-GenPt	PriD-Lab	SecD-Lab	SecC-Lab	Bill-Lab
119	Total DEPRECIATION Exp.	403	762,050						
120									
121	**III. TAXES and OTHER**								
122	**A. GENERAL TAXES**								
123	Payroll related	408	0	-	-	-	-	-	-
124	PURTA, Real estate	408.16	43,311	Plant	Sec-Pt	PriD-Pt	SecD-Pt	SecC-Pt	Bill-Pt
125	Capital stock		0	-	-	-	-	-	-
126	Other	408	837	Plant	Sec-Pt	PriD-Pt	SecD-Pt	SecC-Pt	Bill-Pt
127	Subtotal - General Taxes		44,148						
128									
129	**B. GROSS RECEIPTS TAX**								
130	Gross Receipts tax		375,778	GRT_RevxT	Sec-Rev	Dist_Rev	Dist_Rev	Dist_Rev	Dist_Rev
131	Subtotal- Gross Receipts tax		375,778						
132									

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Wellsboro Electric Company
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Line	Account	No.	Balance	Function	Classify	Class Allocation			
				Allocator	Secondary	PrimDem	SecnDem	SecnCus	BillCus ×
133	**B. FEDERAL / STATE INCOME TAXES**								
134	State Income Tax Expense		(64,035)	StaTax	Sec-StaTax	PreStaTax	PreStaTax	PreStaTax	-
135	Federal Income Tax Expense		(56,996)	FedTax	Sec-FedTax	PreFedTax	PreFedTax	PreFedTax	-
136	Subtotal - Fed / State Inc Tax	409-411	(121,031)						
137	Total TAXES	408-411	298,895						
138									
139	**TOTAL EXPENSES**		5,353,723						
140									
141	**IV. OPERATING REVENUES at Present Rates**								
142	Distribution Revenue		6,369,121	DistBill_RR-PF	Sec-RetRRPF	Dist_Rev	Dist_Rev	Dist_Rev	Dist_Rev
143	Forfeited Discounts		30,962	Bill	-	-	-	-	Write-Offs
144	Rent For Electric Property		273,619	OH_Cond	PTF-Sec-Z	NCP-Prim	NCP-Sec	Avg-Cust-Sec	-
145	Other Electric Revenues		22,899	DistBill_RR-PF	Sec-RetRRPF	Dist_Rev	Dist_Rev	Dist_Rev	Dist_Rev
146	Total REVENUES		6,696,602						
147									
148	TOTAL EXPENSES		5,353,723						
149	**V. NET INCOME at Present Rates**		1,342,878						
150									
151	**SUMMARY REPORT**								
152	OPERATING REVENUES								
153	Utility Revenues	440-446	6,400,084						
154	Other Operating Revenues	450-456	296,518						
155	Total Operating Revenues		6,696,602						
156									
157	OPERATING EXPENSES								
158	Distribution / Transmission	580-599	1,602,629						
159	Customer Acctg & Service	901-919	1,093,791						
160	Admin & General	920-932	1,596,359						
161	Total Operating Expenses		4,292,779						
162									
163	Depreciation Expense	403	762,050						
164	Taxes Other Than Income	408	419,926						
165	INCOME BEFORE INCOME		1,221,847						
166	Income Taxes	409-411	(121,031)						
167	**NET INCOME**		1,342,878						
168									
169	**RATE BASE**		36,015,165						
170	Return on Rate Base		3.73%						
171									

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Wellsboro Electric Company
Embedded Cost of Service Study (ECOSS) (R)
FPFTY Ending December 31, 2026
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Line	Account	No.	Balance	Function Allocator	Classify Secondary	Class Allocation PrimDem	SecnDem	SecnCus	BillCus ×
172	**REVENUE REQUIREMENTS**								
173	Target Rate of Return								
174									
175	Rate Base								
176									
177	Operating expenses								
178	Uncollectibles expense		20,000	BILL	-	-	-	-	Write-Offs
179	Depreciation expense								
180	Regulatory Commission Expenses		153,393	Plant	Sec-Pt	PriD-Pt	SecD-Pt	SecC-Pt	Bill-Pt
181	General taxes / Other								
182	Subtotal- Operating Costs to recover								
183									
184	Target Return on Rate Base- After tax								
185									
186	Income taxes to recover								
187									
188	Subtotal- Rev Req before GRT								
189	GRT needed								
190	**TOTAL REVENUE REQUIREMENT**								
191									
192	Revenue at Present rates								
193	Revenue Excess (Deficiency)								
194									

FuncFc **Wellsboro Electric Company**
Functio **Embedded Cost of Service Study (ECOSS) (R)**
Fac **FPFTY Ending December 31, 2026**
E-5B (F **Functionalization Factors**

0	Allocator Name	In Use	Total	Primary	Secondary	Billing	x
1	None		-				x
2		FALSE	0.00%	0.00%	0.00%	0.00%	x
3							x
4	Tran		1				x
5		TRUE	100.00%	0.00%	0.00%	0.00%	x
6							x
7	Prim		1	1			x
8		TRUE	100.00%	100.00%	0.00%	0.00%	x
9							x
10	Sec		1		1		x
11		TRUE	100.00%	0.00%	100.00%	0.00%	x
12							x
13	Bill		1			1	x
14		TRUE	100.00%	0.00%	0.00%	100.00%	x
15							x
16	OH_Cond		1	1	0	-	x
17		TRUE	100.00%	83.37%	16.63%	0.00%	x
18							x
19	UG_Cond		1	1	0	-	x
20		TRUE	100.00%	57.35%	42.65%	0.00%	x
21							x
22	Trans		1	-	1	-	x
23		TRUE	100.00%	0.00%	100.00%	0.00%	x
24							x
25	UG_Total		1,038,449	595,569	442,880	-	x
26		TRUE	100.00%	57.35%	42.65%	0.00%	x
27							x
28	OpExp_Dist		4,292,779	1,936,320	543,119	1,813,339	x
29		TRUE	100.00%	45.11%	12.65%	42.24%	x
30							x
31	DistBill_RR-PF		8,073,525	4,276,465	1,488,532	2,308,528	x
32		TRUE	100.00%	52.97%	18.44%	28.59%	x
33							x
34	GRT_RevxT		6,400,084	3,373,660	1,174,288	1,852,136	x
35		TRUE	100.00%	52.71%	18.35%	28.94%	x
36							x

FuncFc **Wellsboro Electric Company**
Functio **Embedded Cost of Service Study (ECOSS) (R)**
Fac **FPFTY Ending December 31, 2026**
E-5B (F **Functionalization Factors**

0	Allocator Name	In Use	Total	Primary	Secondary	Billing	x
37	Labor		940,831	429,486	117,817	393,527	x
38		TRUE	100.00%	45.65%	12.52%	41.83%	x
39							x
40	D-Labor-Op		171,910	103,998	40,749	27,164	x
41		TRUE	100.00%	60.50%	23.70%	15.80%	x
42							x
43	D-Labor-Mnt		361,719	291,148	68,938	1,633	x
44		TRUE	100.00%	80.49%	19.06%	0.45%	x
45							x
46	Labor_Pt		2	1	0	1	x
47		TRUE	100.00%	53.70%	18.96%	27.34%	x
48							x
49	IntanPt		284,588	-	-	284,588	x
50		TRUE	100.00%	0.00%	0.00%	100.00%	x
51							x
52	TranPt		-	-	-	-	x
53		FALSE	0.00%	0.00%	0.00%	0.00%	x
54							x
55	OH_UG		26,142,155	18,719,219	7,422,936	-	x
56		TRUE	100.00%	71.61%	28.39%	0.00%	x
57							x
58	DistPt		34,485,748	22,890,353	10,034,297	1,561,098	x
59		TRUE	100.00%	66.38%	29.10%	4.53%	x
60							x
61	GenPtxL		117,901	53,821	14,764	49,315	x
62		TRUE	100.00%	45.65%	12.52%	41.83%	x
63							x
64	RateBase		25,974,028	15,871,362	6,322,861	3,779,805	x
65		TRUE	100.00%	61.10%	24.34%	14.55%	x
66							x
67	PreTax		44,493	292,116	172,981	(420,604)	x
68		TRUE	100.00%	656.54%	388.78%	-945.32%	x
69							x
70	StaTax		465,097	292,116	172,981	-	x
71		TRUE	100.00%	62.81%	37.19%	0.00%	x
72							x
73	FedTax		529,132	332,334	196,798	-	x
74		TRUE	100.00%	62.81%	37.19%	0.00%	x
75							x
76	Plant		44,382,268	27,408,080	11,273,608	5,700,580	x
77		TRUE	100.00%	61.75%	25.40%	12.84%	x

ClassF **Wellsboro Electric Company**
Classi **Embedded Cost of Service Study (ECOSS) (R)**
Fac **FPFTY Ending December 31, 2026**
E-5C (**Classification Factors**

0	Allocator Name	In Use	Total	Demand	Commodity	Customer
1	None		0			
2		FALSE	0.00%	0.00%	0.00%	0.00%
3						
4	Demand		1	1		
5		TRUE	100.00%	100.00%	0.00%	0.00%
6						
7	Commodity		1		1	
8		TRUE	100.00%	0.00%	100.00%	0.00%
9						
10	Customer		1			1
11		TRUE	100.00%	0.00%	0.00%	100.00%
12						
13	PTF-Sec-Z		100.00%	36.96%	0.00%	63.04%
14		TRUE	100.00%	36.96%	0.00%	63.04%
15						
16	OH-Sec-Z		100.00%	43.97%	0.00%	56.03%
17		TRUE	100.00%	43.97%	0.00%	56.03%
18						
19	UG-Sec-Z		100.00%	63.71%	0.00%	36.29%
20		TRUE	100.00%	63.71%	0.00%	36.29%
21						
22	Trans-Min		100.00%	22.45%	0.00%	77.55%
23		TRUE	100.00%	22.45%	0.00%	77.55%
24						
25	Sec_RB		6,322,861	1,866,208	-	4,456,653
26		TRUE	100.00%	29.52%	0.00%	70.48%
27						
28	Sec-Pt		11,273,608	3,085,449	-	8,188,159
29		TRUE	100.00%	27.37%	0.00%	72.63%
30						
31	Sec-RB		6,322,861	1,866,208	-	4,456,653
32		TRUE	100.00%	29.52%	0.00%	70.48%
33						
34	Sec-OH_UG		26,907,378	18,719,219	-	8,188,159
35		TRUE	100.00%	69.57%	0.00%	30.43%
36						

ClassF **Wellsboro Electric Company**
Classi **Embedded Cost of Service Study (ECOSS) (R)**
Fac **FPFTY Ending December 31, 2026**
E-5C (**Classification Factors**

0	Allocator Name	In Use	Total	Demand	Commodity	Customer
37	Sec-GenPt		1,239,311	632,509	-	606,802
38		TRUE	100.00%	51.04%	0.00%	48.96%
39						
40	Sec-OpExp		543,119	256,620	-	286,499
41		TRUE	100.00%	47.25%	0.00%	52.75%
42						
43	Sec-DiPt		10,034,297	2,452,940	-	7,581,357
44		TRUE	100.00%	24.45%	0.00%	75.55%
45						
46	Sec-Lab		117,817	60,131	-	57,687
47		TRUE	100.00%	51.04%	0.00%	48.96%
48						
49	Sec-Rev		1,174,288	415,680	-	758,608
50		TRUE	100.00%	35.40%	0.00%	64.60%
51						
52	Sec-LabPt		200.00%	78.41%	0.00%	121.59%
53		TRUE	100.00%	39.20%	0.00%	60.80%
54						
55	Sec-PreTax		172,981	27,676	-	145,306
56		TRUE	100.00%	16.00%	0.00%	84.00%
57						
58	Sec-StaTax		172,981	27,676	-	145,306
59		TRUE	100.00%	16.00%	0.00%	84.00%
60						
61	Sec-FedTax		196,798	31,486	-	165,312
62		TRUE	100.00%	16.00%	0.00%	84.00%
63						
64	Sec-RetRRPF		1,488,532	526,917	-	961,615
65		TRUE	100.00%	35.40%	0.00%	64.60%
66						

AllocFctr **Wellsboro Electric Company**
Class Alloca **Embedded Cost of Service Study (ECOSS) (R)**
Fac **FPFTY Ending December 31, 2026**
E-5D (R) **Class Allocation Factors**

0	Allocator Name	In Use	Total	RS	RSAE	NRS	NRH	CS	CSH	IS	MSL	POL	EX
1	None		-										
2		FALSE	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
3													
4	MWh-Meter		105,165,077	44,639,052	394,372	4,657,346	6,256	28,611,970	7,216	26,746,293	-	-	102,572
5		TRUE	100.00%	42.45%	0.38%	4.43%	0.01%	27.21%	0.01%	25.43%	0.00%	0.00%	0.10%
6													
7	NCP-Prim		20036	9,206	123	846	9	5,356	18	4,411	13	41	12
8		TRUE	100.00%	45.95%	0.61%	4.22%	0.04%	26.73%	0.09%	22.01%	0.07%	0.21%	0.06%
9													
10	NCP-Sec		15,613	9,206	123	846	9	5,356	18	-	13	41	-
11		TRUE	100.00%	58.96%	0.79%	5.42%	0.06%	34.31%	0.12%	0.00%	0.09%	0.27%	0.00%
12													
13	NCP-Ltr		3,705	-	-	-	4	3,632	14	-	13	41	-
14		TRUE	100.00%	0.00%	0.00%	0.00%	0.12%	98.03%	0.37%	0.00%	0.36%	1.12%	0.00%
15													
16	AVG-CUST		6,497	5,139	29	923	1	386	1	14	-	-	4
17		TRUE	100.00%	79.10%	0.45%	14.21%	0.02%	5.94%	0.02%	0.22%	0.00%	0.00%	0.06%
18													
19	Services_Cost		5,310,086	3,937,424	22,155	707,421	766	618,293	1,602	22,425	-	-	-
20		TRUE	100.00%	74.15%	0.42%	13.32%	0.01%	11.64%	0.03%	0.42%	0.00%	0.00%	0.00%
21													
22	Avg-Cust-Sec		6,483	5,139	29	923	1	386	1		-	-	4
23		TRUE	100.00%	79.27%	0.45%	14.24%	0.02%	5.95%	0.02%	0.00%	0.00%	0.00%	0.06%
24													
25	Meters		6,497	5,139	29	923	1	386	1	14	-	-	4
26		TRUE	100.00%	79.10%	0.45%	14.21%	0.02%	5.94%	0.02%	0.22%	0.00%	0.00%	0.06%
27													
28	Meter_Cost		3,076,038	1,850,100	10,410	332,400	360	666,410	1,726	166,936	-	-	47,696
29		TRUE	100.00%	60.15%	0.34%	10.81%	0.01%	21.66%	0.06%	5.43%	0.00%	0.00%	1.55%
30													

AllocFctr **Wellsboro Electric Company**
Class Alloca **Embedded Cost of Service Study (ECOSS) (R)**
Fac **FPFTY Ending December 31, 2026**
E-5D (R) **Class Allocation Factors**

0	Allocator Name	In Use	Total	RS	RSAE	NRS	NRH	CS	CSH	IS	MSL	POL	EX
31	Dist_Rev		6,369,121	3,357,674	24,383	490,753	676	1,510,082	1,028	880,700	13,496	81,371	8,957
32		TRUE	100.00%	52.72%	0.38%	7.71%	0.01%	23.71%	0.02%	13.83%	0.21%	1.28%	0.14%
33													
34	Total_Rev		13,039,628	6,968,890	53,191	826,557	1,630	3,210,823	1,585	1,858,613	19,106	81,371	17,863
35		TRUE	100.00%	53.44%	0.41%	6.34%	0.01%	24.62%	0.01%	14.25%	0.15%	0.62%	0.14%
36													
37	Supp_Rev		6,670,507	3,611,216	28,807	335,804	954	1,700,741	557	977,913	5,609	-	8,907
38		TRUE	100.00%	54.14%	0.43%	5.03%	0.01%	25.50%	0.01%	14.66%	0.08%	0.00%	0.13%
39													
40	CustDeposits		121,200	69,887	513	6,802	18	27,394	14	15,694	-	721	158
41		TRUE	100.00%	57.66%	0.42%	5.61%	0.01%	22.60%	0.01%	12.95%	0.00%	0.59%	0.13%
42													
43	Write-Offs		1	1	0	0	0	0	0	0	-	0	0
44		TRUE	100.00%	86.99%	0.64%	1.66%	0.00%	6.67%	0.00%	3.82%	0.00%	0.18%	0.04%
45													
46	StLgt-Lamps		2	-	-	-	-	-	-	-	1	1	-
47		TRUE	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	50.00%	50.00%	0.00%
48													
49	PriD-Lab		429,486	197,340	2,640	18,128	189	114,812	390	94,546	288	888	265
50		TRUE	100.00%	45.95%	0.61%	4.22%	0.04%	26.73%	0.09%	22.01%	0.07%	0.21%	0.06%
51													
52	PriD-DxPt		22,890,353	10,517,637	140,713	966,155	10,050	6,119,146	20,807	5,039,033	15,374	47,324	14,115
53		TRUE	100.00%	45.95%	0.61%	4.22%	0.04%	26.73%	0.09%	22.01%	0.07%	0.21%	0.06%
54													
55	PriD-Pt		27,408,080	12,593,437	168,485	1,156,839	12,033	7,326,843	24,913	6,033,556	18,408	56,664	16,901
56		TRUE	100.00%	45.95%	0.61%	4.22%	0.04%	26.73%	0.09%	22.01%	0.07%	0.21%	0.06%
57													
58	PriD-LabPt		200.00%	91.90%	1.23%	8.44%	0.09%	53.46%	0.18%	44.03%	0.13%	0.41%	0.12%
59		TRUE	100.00%	45.95%	0.61%	4.22%	0.04%	26.73%	0.09%	22.01%	0.07%	0.21%	0.06%
60													
61	PriD-OpExp		1,936,320	889,698	11,903	81,728	850	517,625	1,760	426,257	1,301	4,003	1,194
62		TRUE	100.00%	45.95%	0.61%	4.22%	0.04%	26.73%	0.09%	22.01%	0.07%	0.21%	0.06%
63													

AllocFctr **Wellsboro Electric Company**
Class Alloca **Embedded Cost of Service Study (ECOSS) (R)**
Fac **FPFTY Ending December 31, 2026**
E-5D (R) **Class Allocation Factors**

0	Allocator Name	In Use	Total	RS	RSAE	NRS	NRH	CS	CSH	IS	MSL	POL	EX
64	SecD-Lab		60,131	34,966	468	3,212	34	21,158	72	-	54	167	-
65		TRUE	100.00%	58.15%	0.78%	5.34%	0.06%	35.19%	0.12%	0.00%	0.09%	0.28%	0.00%
66													
67	SecD-DxPt		2,452,940	1,000,820	13,390	91,936	1,839	1,323,013	4,783	-	4,208	12,952	-
68		TRUE	100.00%	40.80%	0.55%	3.75%	0.07%	53.94%	0.20%	0.00%	0.17%	0.53%	0.00%
69													
70	SecD-Pt		3,085,449	1,368,621	18,310	125,722	2,201	1,545,570	5,543	-	4,777	14,704	-
71		TRUE	100.00%	44.36%	0.59%	4.07%	0.07%	50.09%	0.18%	0.00%	0.15%	0.48%	0.00%
72													
73	SecD-UG		282,151	166,369	2,226	15,283	159	96,793	329	-	243	749	-
74		TRUE	100.00%	58.96%	0.79%	5.42%	0.06%	34.31%	0.12%	0.00%	0.09%	0.27%	0.00%
75													
76	SecD-LabPt		200.00%	102.51%	1.37%	9.42%	0.13%	85.28%	0.30%	0.00%	0.24%	0.75%	0.00%
77		TRUE	100.00%	51.25%	0.69%	4.71%	0.06%	42.64%	0.15%	0.00%	0.12%	0.38%	0.00%
78													
79	SecD-OpExp		256,620	146,543	1,961	13,462	149	93,192	320	-	244	750	-
80		TRUE	100.00%	57.11%	0.76%	5.25%	0.06%	36.32%	0.12%	0.00%	0.09%	0.29%	0.00%
81													
82	SecC-Lab		57,687	44,788	252	8,047	9	3,517	9	11	510	510	33
83		TRUE	100.00%	77.64%	0.44%	13.95%	0.02%	6.10%	0.02%	0.02%	0.88%	0.88%	0.06%
84													
85	SecC-DxPt		7,581,357	5,782,967	32,539	1,039,002	1,125	585,370	1,517	10,499	62,636	62,636	3,066
86		TRUE	100.00%	76.28%	0.43%	13.70%	0.01%	7.72%	0.02%	0.14%	0.83%	0.83%	0.04%
87													
88	SecC-Pt		8,188,159	6,254,091	35,190	1,123,647	1,217	622,361	1,612	10,611	68,006	68,006	3,418
89		TRUE	100.00%	76.38%	0.43%	13.72%	0.01%	7.60%	0.02%	0.13%	0.83%	0.83%	0.04%
90													
91	SecC-LTr		2,609,971	2,068,828	11,641	371,698	403	155,389	403	-	-	-	1,610
92		TRUE	100.00%	79.27%	0.45%	14.24%	0.02%	5.95%	0.02%	0.00%	0.00%	0.00%	0.06%
93													

AllocFctr **Wellsboro Electric Company**
Class Alloca **Embedded Cost of Service Study (ECOSS) (R)**
Fac **FPFTY Ending December 31, 2026**
E-5D (R) **Class Allocation Factors**

0	Allocator Name	In Use	Total	RS	RSAE	NRS	NRH	CS	CSH	IS	MSL	POL	EX
94	SecC-LabPt		2	2	0	0	0	0	0	0	0	0	0
95		TRUE	100.00%	77.01%	0.43%	13.84%	0.01%	6.85%	0.02%	0.07%	0.86%	0.86%	0.05%
96													
97	SecC-OpExp		286,499	222,961	1,255	40,059	43	18,111	47	95	1,884	1,884	161
98		TRUE	100.00%	77.82%	0.44%	13.98%	0.02%	6.32%	0.02%	0.03%	0.66%	0.66%	0.06%
99													
100	Bill-Lab		393,527	303,902	1,710	54,601	59	29,486	76	2,872	-	-	821
101		TRUE	100.00%	77.23%	0.43%	13.87%	0.02%	7.49%	0.02%	0.73%	0.00%	0.00%	0.21%
102													
103	Bill-DxLab		28,989	17,703	100	3,181	3	6,059	16	1,500	-	-	429
104		TRUE	100.00%	61.07%	0.34%	10.97%	0.01%	20.90%	0.05%	5.17%	0.00%	0.00%	1.48%
105													
106	Bill-DxPt		1,561,098	1,037,398	5,837	186,385	202	256,502	665	57,641	-	-	16,469
107		TRUE	100.00%	66.45%	0.37%	11.94%	0.01%	16.43%	0.04%	3.69%	0.00%	0.00%	1.05%
108													
109	Bill-Pt		5,700,580	4,234,121	23,824	760,727	824	566,663	1,468	87,852	-	-	25,101
110		TRUE	100.00%	74.28%	0.42%	13.34%	0.01%	9.94%	0.03%	1.54%	0.00%	0.00%	0.44%
111													
112	Bill-LabPt		200.00%	151.50%	0.85%	27.22%	0.03%	17.43%	0.05%	2.27%	0.00%	0.00%	0.65%
113		TRUE	100.00%	75.75%	0.43%	13.61%	0.01%	8.72%	0.02%	1.14%	0.00%	0.00%	0.32%
114													
115	Bill-OpExp		1,813,339	1,377,084	8,152	240,415	305	151,266	415	31,276	659	854	2,913
116		TRUE	100.00%	75.94%	0.45%	13.26%	0.02%	8.34%	0.02%	1.72%	0.04%	0.05%	0.16%
117													
118	PreTax		44,493	(407,257)	(9,282)	(42,882)	(1,300)	277,414	(2,793)	157,745	6,012	65,085	1,751
119		TRUE	100.00%	(915.3%)	(20.9%)	(96.4%)	(2.9%)	623.5%	(6.3%)	354.5%	13.5%	146.3%	3.9%
120													
121	PreStaTax		44,666,856	24,675,367	247,076	3,207,378	16,319	10,078,344	33,581	6,132,632	91,191	139,374	45,595
122		TRUE	100.00%	55.24%	0.55%	7.18%	0.04%	22.56%	0.08%	13.73%	0.20%	0.31%	0.10%
123													
124	PreFedTax		44,666,856	24,675,367	247,076	3,207,378	16,319	10,078,344	33,581	6,132,632	91,191	139,374	45,595
125		TRUE	100.00%	55.24%	0.55%	7.18%	0.04%	22.56%	0.08%	13.73%	0.20%	0.31%	0.10%
126													
127	Plant		44,666,856	24,675,367	247,076	3,207,378	16,319	10,078,344	33,581	6,132,632	91,191	139,374	45,595
128		TRUE	100.00%	55.24%	0.55%	7.18%	0.04%	22.56%	0.08%	13.73%	0.20%	0.31%	0.10%
129													
130	RateBase		25,974,028	14,389,602	144,196	1,873,193	9,464	5,741,037	19,230	3,524,195	111,670	138,695	22,745
131		TRUE	100.00%	55.40%	0.56%	7.21%	0.04%	22.10%	0.07%	13.57%	0.43%	0.53%	0.09%
132													

WP (R)

Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026 (R)
INDEX TO WORKPAPERS

Line		DESCRIPTION	PERIOD
1	WP (R)	Index To Workpapers	
2	WP_B1 (R)	Monthly Billing Units, Rates And Revenue	HY 2024- Present Rates
3	WP_B2 (R)	Historic Sales and Revenue	Historic Sales and Revenue
4	WP_B3 (R)	Historic Billing Units	Historic Billing Units
5	WP_B4 (R)	Sales Recap	Period Ending December 31, 2024
6	WP_B5 (R)	Total Operating Revenues	January 1, 2024 to December 31, 2024
7	WP_C1 (R)	Expenses By Account and By Type	Year 2023, HY 2024, FTY 2025 and FPFTY 2026
8	WP_C2 (R)	Expenses By Account	Year 2013, HY 2024, FTY 2025 and FPFTY 2026
9	WP_C3 (R)	Accumulated Deferred Income Taxes	Years 2024 through 2026

Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026 (R)
Monthly Billing Units, Rates And Revenue
HY 2024- Present Rates

		Sch. 1- RS	Sch. 2- RSAE	Sch. 3- NRS	Sch. 3- NRH	Sch. 4- CS	Sch. 4- CSH	Sch. 5- IS	Sch. 6- MSL	Sch. 7- POL	Sch. 8- EU	Total
1												
2		**BILLING UNITS**										
3		**kWh Sales HY 2024**										
4	Jan-24	4,000,928	38,314	373,296	801	2,365,819	440	2,029,329	5,519	16,856	8,415	8,839,717
5	Feb-24	3,891,863	40,795	374,369	1,548	2,342,175	520	1,984,942	5,389	16,856	8,654	8,667,111
6	Mar-24	3,636,509	39,216	379,223	2,020	2,352,274	520	1,864,451	5,389	16,856	7,983	8,304,441
7	Apr-24	3,344,243	33,184	348,420	1,533	2,135,105	480	2,066,009	5,389	16,856	8,201	7,959,420
8	May-24	2,881,391	24,071	294,649	434	1,901,201	400	2,050,885	5,389	16,856	7,694	7,182,970
9	Jun-24	2,990,307	18,248	301,734	549	2,105,258	480	2,339,790	5,389	16,856	8,191	7,786,802
10	Jul-24	3,759,704	19,564	337,055	750	2,285,778	760	2,215,131	5,389	16,856	8,790	8,649,777
11	Aug-24	3,810,940	19,449	332,303	748	2,324,893	1,000	2,153,540	5,389	16,856	8,426	8,673,544
12	Sep-24	3,481,321	19,264	316,634	725	2,269,507	680	1,928,775	5,389	16,856	7,922	8,047,073
13	Oct-24	2,836,841	16,643	278,416	680	2,002,556	520	1,911,524	5,389	16,856	7,068	7,076,493
14	Nov-24	3,213,097	25,133	301,310	591	2,131,623	280	2,034,009	5,389	16,856	9,268	7,737,556
15	Dec-24	3,601,220	31,854	321,421	447	2,073,041	400	2,031,795	5,389	16,856	11,960	8,094,383
16		41,448,363	325,735	3,958,829	10,826	26,289,234	6,480	24,610,180	64,798	202,270	102,572	97,019,287
17	Adj for POL	41,448,363	325,735	3,958,829	10,826	26,289,234	6,480	24,610,180	64,798	202,270	102,572	97,019,287
18		**GSSR Sales HY 2024**										
19	Jan-24	4,000,928	38,314	373,296	801	2,365,819	440	1,679,575	5,519			8,464,692
20	Feb-24	3,891,863	40,795	374,369	1,548	2,342,175	520	1,541,833	5,389			8,198,492
21	Mar-24	3,636,509	39,216	379,223	2,020	2,352,274	520	1,430,263	5,389			7,845,414
22	Apr-24	3,344,243	33,184	348,420	1,533	2,135,105	480	1,628,350	5,389			7,496,704
23	May-24	2,881,391	24,071	294,649	434	1,901,201	400	1,588,305	5,389			6,695,840
24	Jun-24	2,990,307	18,248	301,734	549	2,105,258	480	1,852,581	5,389			7,274,546
25	Jul-24	3,759,704	19,564	337,055	750	2,285,778	760	1,742,150	5,389			8,151,150
26	Aug-24	3,810,940	19,449	332,303	748	2,324,893	1,000	1,670,147	5,389			8,164,869
27	Sep-24	3,481,321	19,264	316,634	725	2,269,507	680	1,478,126	5,389			7,571,646
28	Oct-24	2,836,841	16,643	278,416	680	2,002,556	520	1,501,093	5,389			6,642,138
29	Nov-24	3,213,097	25,133	301,310	591	2,131,623	280	1,586,405	5,389			7,263,828
30	Dec-24	3,601,220	31,854	321,421	447	2,073,041	400	1,661,555	5,389			7,695,327
31		41,448,363	325,735	3,958,829	10,826	26,289,234	6,480	19,360,383	64,798	0	0	91,464,648

Wellsboro Electric Company
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HY 2024- Present Rates

		Sch. 1- RS	Sch. 2- RSAE	Sch. 3- NRS	Sch. 3- NRH	Sch. 4- CS	Sch. 4- CSH	Sch. 5- IS	Sch. 6- MSL	Sch. 7- POL	Sch. 8- EU	Total
Full Month Customers HY 2024												
Jan-24		5,124	31	901	2	379	1	13			4	6,455
Feb-24		5,122	31	901	2	381	1	13			4	6,455
Mar-24		5,123	31	903	2	381	1	13			4	6,458
Apr-24		5,125	30	904	1	382	1	13			4	6,460
May-24		5,127	30	910	1	379	1	13			4	6,465
Jun-24		5,131	30	909	1	379	1	13			4	6,468
Jul-24		5,138	30	911	1	380	1	13			4	6,478
Aug-24		5,136	29	912	1	380	1	13			4	6,476
Sep-24		5,135	29	911	1	381	1	13			4	6,475
Oct-24		5,139	29	910	1	382	1	13			4	6,479
Nov-24		5,129	29	910	1	384	1	13			4	6,471
Dec-24		5,127	29	911	1	385	1	13			4	6,471
Annual Bills		61,556	358	10,893	15	4,573	12	156	0	0	48	77,611
Average Monthly E		5,130	30	908	1	381	1	13	0	0	4	6,468
Monthly Billing Units- Public Lighting and Street Lighting HY 2024												
Rate 1							Mercury	7000 lumens	0	0		0
Rate 2							Mercury	20000 lumens	1	1		2
Rate 3							Sodium	9500 lumens	0	0		0
Rate 4							Sodium	16000 lumens	0	0		0
							LED	50 OH	148	425		573
							LED	50 UG	0	0		0
							LED	50 UG Col	0	0		0
							LED	70 OH	109	364		473
							LED	70 UG	0	0		0
							LED	140 OH	0	2		2
							LED	140 UG	0	0		0
									258	792		1,050

Wellsboro Electric Company
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			Sch. 1- RS	Sch. 2- RSAE	Sch. 3- NRS	Sch. 3- NRH	Sch. 4- CS	Sch. 4- CSH	Sch. 5- IS	Sch. 6- MSL	Sch. 7- POL	Sch. 8- EU	Total
62			**RATES AND CHARGES**										
63			**Tariff Rates**										
64	Customer Ch	Jan-J	$12.00	$12.00	$12.22	$12.22	$32.03	$45.81	$85.00				
65		Jul-S	$12.00	$12.00	$12.22	$12.22	$32.03	$45.81	$85.00				
66		Oct-I	$12.00	$12.00	$12.22	$12.22	$32.03	$45.81	$85.00				
67													
68	Energy Block	Jan-J	$0.058640	$0.051270	$0.076300	$0.084690	$0.022680	$0.066280	$0.020780			$0.087320	
69		Jul-S	$0.058640	$0.051270	$0.076300	$0.084690	$0.022680	$0.066280	$0.020780			$0.087320	
70		Oct-I	$0.058640	$0.051270	$0.076300	$0.084690	$0.022680	$0.066280	$0.020780			$0.087320	
71													
72	Energy Block	Jan-Jun							$0.001300				
73		Jul-Sep							$0.001300				
74		Oct-Dec							$0.001300				
75													
76	Block 1 Demand								100				
77	Demand Bloc	Jan-Jun					$6.60		$10.00				
78		Jul-Sep					$6.60		$10.00				
79		Oct-Dec					$6.60		$10.00				
80													
81	E-Factor Mar-Jun												
82	E-Factor Jul-Dec												
83	Block 1 Energy = Demand X								130				
84													
85	CCSC Charg	Jan-J	$0.000000	$0.000000	$0.000000	$0.000000	$0.000000	$0.000000	$0.000000	$0.000000	$0.000000	$0.000000	
86		Jul-D	$0.000000	$0.000000	$0.000000	$0.000000	$0.000000	$0.000000	$0.000000	$0.000000	$0.000000	$0.000000	
87	STAS Rate		0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%		
88													

Wellsboro Electric Company
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HY 2024- Present Rates

		Sch. 1- RS	Sch. 2- RSAE	Sch. 3- NRS	Sch. 3- NRH	Sch. 4- CS	Sch. 4- CSH	Sch. 5- IS	Sch. 6- MSL	Sch. 7- POL	Sch. 8- EU	Total
89		**COMPUTATION OF REVENUE**										
90		**Customer Charge Revenue- Full Month Customers**										
91	Jan-24	$61,488	$372	$11,010	$24	$12,139	$46	$1,105	$0	$0	$0	$86,185
92	Feb-24	61,464	372	11,010	24	12,203	46	1,105				86,225
93	Mar-24	61,476	372	11,035	24	12,203	46	1,105				86,261
94	Apr-24	61,500	360	11,047	12	12,235	46	1,105				86,305
95	May-24	61,524	360	11,120	12	12,139	46	1,105				86,307
96	Jun-24	61,572	360	11,108	12	12,139	46	1,105				86,342
97	Jul-24	61,656	360	11,132	12	12,171	46	1,105				86,483
98	Aug-24	61,632	348	11,145	12	12,171	46	1,105				86,459
99	Sep-24	61,620	348	11,132	12	12,203	46	1,105				86,467
100	Oct-24	61,668	348	11,120	12	12,235	46	1,105				86,535
101	Nov-24	61,548	348	11,120	12	12,300	46	1,105				86,479
102	Dec-24	61,524	348	11,132	12	12,332	46	1,105				86,499
103		$738,672	$4,296	$133,112	$183	$146,473	$550	$13,260	$0	$0	$0	$1,036,547
104												
105		**Distribution kWh Revenue**										
106	Jan-24	$234,614	$1,964	$28,482	$68	$53,657	$29	$14,368	$1,131	$6,806	$735	$341,855
107	Feb-24	228,219	2,092	28,564	131	53,121	34	14,589	1,131	6,806	756	335,442
108	Mar-24	213,245	2,011	28,935	171	53,350	34	14,464	1,131	6,806	697	320,843
109	Apr-24	196,106	1,701	26,584	130	48,424	32	14,848	1,131	6,806	716	296,479
110	May-24	168,965	1,234	22,482	37	43,119	27	15,261	1,131	6,806	672	259,733
111	Jun-24	175,352	936	23,022	46	47,747	32	16,478	1,131	6,806	715	272,265
112	Jul-24	220,469	1,003	25,717	64	51,841	50	16,575	1,131	6,806	768	324,424
113	Aug-24	223,474	997	25,355	63	52,729	66	16,511	1,131	6,806	736	327,867
114	Sep-24	204,145	988	24,159	61	51,472	45	16,000	1,131	6,806	692	305,499
115	Oct-24	166,352	853	21,243	58	45,418	34	15,501	1,131	6,806	617	258,014
116	Nov-24	188,416	1,289	22,990	50	48,345	19	14,658	1,131	6,806	809	284,513
117	Dec-24	211,176	1,633	24,524	38	47,017	27	14,360	1,131	6,806	1,044	307,755
118		$2,430,532	$16,700	$302,059	$917	$596,240	$429	$183,612	$13,576	$81,667	$8,957	$3,634,689
119												
120		**Distribution Demand Revenue**										
121	Jan-24					$52,012		$46,319				$98,331
122	Feb-24					53,663		47,420				101,083
123	Mar-24					51,176		47,543				98,719
124	Apr-24					51,107		48,025				99,132
125	May-24					52,645		49,736				102,380
126	Jun-24					55,868		53,058				108,925
127	Jul-24					59,302		54,079				113,381
128	Aug-24					59,833		54,144				113,977
129	Sep-24					58,429		53,280				111,709
130	Oct-24					56,828		51,398				108,226
131	Nov-24					55,505		47,440				102,946
132	Dec-24					55,023		46,273				101,296
133		$0	$0	$0	$0	$661,390	$0	$598,716	$0	$0	$0	$1,260,106
134				*$0*		*$671,699*		*$598,716*				*$1,270,414*
135		**STAS Revenue- Distribution**										

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1		Sch. 1- RS	Sch. 2- RSAE	Sch. 3- NRS	Sch. 3- NRH	Sch. 4- CS	Sch. 4- CSH	Sch. 5- IS	Sch. 6- MSL	Sch. 7- POL	Sch. 8- EU	Total
136	STAS Revenue											
137		(697)	(5)	(72)	(0)	(319)	(0)	(175)	(2)		0	(1,270)
138							**GSSR Revenue**					
139	GSSR Revenue	3,611,216	28,807	335,804	954	1,700,741	557	977,913	5,609		8,907	6,670,507
140												
141												
142							**Total Revenue**					
143	Revenue excluding	6,780,420	49,804	770,975	2,054	3,104,844	1,536	1,773,500	19,185	81,667	17,863	12,601,848
144	POL	53,230	413	14,909		13,115				(81,667)		0
145												
146	Total Revenue	6,833,650	50,217	785,884	2,054	3,117,958	1,536	1,773,500	19,185	0	17,863	12,601,848
147		6,834,759	50,237	784,194	2,066	3,125,447	1,536	1,771,907	19,067		17,863	12,607,075
148												12,607,075

Wellsboro Electric Company
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		Sch. 1- RS	Sch. 2- RSAE	Sch. 3- NRS	Sch. 3- NRH	Sch. 4- CS	Sch. 4- CSH	Sch. 5- IS	Sch. 6- MSL	Sch. 7- POL	Sch. 8- EU	Total
149		**BILLING UNITS- DETAIL**										
150		**Block 1 kWh Sales HY 2024**										
151	Jan-24	4,000,928	38,314	373,296	801	2,365,819	440	602,152	5,519	16,856	8,415	7,412,540
152	Feb-24	3,891,863	40,795	374,369	1,548	2,342,175	520	616,456	5,389	16,856	8,654	7,298,625
153	Mar-24	3,636,509	39,216	379,223	2,020	2,352,274	520	618,064	5,389	16,856	7,983	7,058,054
154	Apr-24	3,344,243	33,184	348,420	1,533	2,135,105	480	624,328	5,389	16,856	8,201	6,517,739
155	May-24	2,881,391	24,071	294,649	434	1,901,201	400	646,564	5,389	16,856	7,694	5,778,649
156	Jun-24	2,990,307	18,248	301,734	549	2,105,258	480	689,748	5,389	16,856	8,191	6,136,760
157	Jul-24	3,759,704	19,564	337,055	750	2,285,778	760	703,028	5,389	16,856	8,790	7,137,674
158	Aug-24	3,810,940	19,449	332,303	748	2,324,893	1,000	703,871	5,389	16,856	8,426	7,223,875
159	Sep-24	3,481,321	19,264	316,634	725	2,269,507	680	692,644	5,389	16,856	7,922	6,810,942
160	Oct-24	2,836,841	16,643	278,416	680	2,002,556	520	668,177	5,389	16,856	7,068	5,833,146
166	Nov-24	3,213,097	25,133	301,310	591	2,131,623	280	616,724	5,389	16,856	9,268	6,320,271
167	Dec-24	3,601,220	31,854	321,421	447	2,073,041	400	601,550	5,389	16,856	11,960	6,664,138
168		41,448,363	325,735	3,958,829	10,826	26,289,234	6,480	7,783,305	64,798	202,270	102,572	80,192,412
169												
170		**Block 2 kWh Sales HY 2024**										
171	Jan-24							1,427,177				1,427,177
172	Feb-24							1,368,486				1,368,486
173	Mar-24							1,246,387				1,246,387
174	Apr-24							1,441,681				1,441,681
175	May-24							1,404,321				1,404,321
176	Jun-24							1,650,043				1,650,043
177	Jul-24							1,512,103				1,512,103
178	Aug-24							1,449,669				1,449,669
179	Sep-24							1,236,131				1,236,131
180	Oct-24							1,243,347				1,243,347
181	Nov-24							1,417,285				1,417,285
182	Dec-24							1,430,245				1,430,245
183		0	0	0	0	0	0	16,826,875	0	0	0	16,826,875
184												97,019,287
185		**Block 1 kW Demand HY 2024**										
186	Jan-24				From Demand	7,881		4,632	From Demand file			12,513
187	Feb-24					8,131		4,742				12,873
188	Mar-24					7,754		4,754				12,508
189	Apr-24					7,744		4,803				12,546
190	May-24					7,976		4,974				12,950
191	Jun-24					8,465		5,306				13,771
192	Jul-24					8,985		5,408				14,393
193	Aug-24					9,066		5,414				14,480
194	Sep-24					8,853		5,328				14,181
195	Oct-24					8,610		5,140				13,750
196	Nov-24					8,410		4,744				13,154
197	Dec-24					8,337		4,627				12,964
198		0	0	0	0	100,211	0	59,872	0	0	0	160,082
199												

Wellsboro Electric Company
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1	Sch. 1- RS	Sch. 2- RSAE	Sch. 3- NRS	Sch. 3- NRH	Sch. 4- CS	Sch. 4- CSH	Sch. 5- IS	Sch. 6- MSL	Sch. 7- POL	Sch. 8- EU	Total
			RCL								
	Total kWh	RS	NRS Tot kWh		Total CS kWh- TCL		Total IS kWh	TCP kWh	RCP kWh		
Jan-24	4,000,928	4,011,825	376,362		2,368,626		2,029,329	698,575	1,330,754		
Feb-24	3,891,863	3,902,760	377,435		2,344,982		1,984,942	695,233	1,289,709		
Mar-24	3,636,509	3,647,406	382,289		2,355,081		1,864,451	664,603	1,199,848		
Apr-24	3,344,243	3,355,140	351,486		2,137,912		2,066,009	713,890	1,352,119		
May-24	2,881,391	2,892,288	297,715		1,904,008		2,050,885	735,645	1,315,240		
Jun-24	2,990,307	3,001,204	304,800		2,108,065		2,339,790	863,541	1,476,249		
Jul-24	3,759,704	3,770,601	340,121		2,288,585		2,215,131	939,350	1,275,781		
Aug-24	3,810,940	3,821,837	335,369		2,327,700		2,153,540	894,347	1,259,193		
Sep-24	3,481,321	3,492,218	319,700		2,272,314		1,928,775	772,826	1,155,949		
Oct-24	2,836,841	2,847,738	281,482		2,005,363		1,911,524	719,113	1,192,411		
Nov-24	3,213,097	3,223,994	304,376		2,134,430		2,034,009	704,465	1,329,544		
Dec-24	3,601,220	3,612,117	324,487		2,075,848		2,031,795	639,875	1,391,920		
	41,448,363	41,579,128	3,995,622		26,322,914		24,610,180	9,041,463	15,568,717		

	Total kWh					
	RL	RFL	TL	TOTAL		RSAE
Jan-24	2,878,005	109,229	1,024,591	4,011,825		38,400
Feb-24	2,775,040	109,210	1,018,510	3,902,760		40,881
Mar-24	2,563,062	99,030	985,314	3,647,406		39,302
Apr-24	2,408,971	93,758	852,411	3,355,140		33,270
May-24	2,060,811	84,343	747,134	2,892,288		24,157
Jun-24	2,181,632	83,679	735,893	3,001,204		18,334
Jul-24	2,789,297	98,533	882,771	3,770,601		19,650
Aug-24	2,687,911	96,275	1,037,651	3,821,837		19,535
Sep-24	2,459,982	87,004	945,232	3,492,218		19,350
Oct-24	2,048,006	77,048	722,684	2,847,738		16,729
Nov-24	2,339,080	86,582	798,332	3,223,994		25,219
Dec-24	2,668,152	89,901	854,064	3,612,117		31,940
	29,859,949	1,114,592	10,604,587	41,579,128		326,767

MSL

	ML Monthly Lamps						
	MV175	SV100	LED50 OH	LED70 OH	Total		
Lamps			148.00	108.92	257		
Monthly kWh / Lamp			18	25			
Monthly kWh			2,664	2,723	5,387	64,643	Annual
Monthly Charge / Lamp	6.09	7.45	4.12	4.69			
Distribution Revenue	0	0	610	511	1,121	13,447	Annual

WP_B2 (R)

Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026 (R)
Monthly Billing Units, Rates And Revenue
Historic Sales and Revenue

				Actual	Actual	Actual	Actual	Actual
1	**KWh**							
2	Rate Class			2020	2021	2022	2023	2024
3	Residential	RS	TL	10,994,242	11,252,118	11,110,832	10,539,016	10,604,587
4	Residential	RS	RL	31,324,751	31,733,114	31,136,489	29,627,494	29,859,949
5	Residential	RS	RFL	1,482,991	1,282,060	1,213,436	1,142,592	1,114,592
6	Residential	RSAE	RSAE	448,709	428,550	407,590	360,384	326,767
7	Commercial	CS	TCL	26,250,627	26,911,703	27,823,411	26,651,913	26,322,914
8	Commercial	NRS	RCL	4,214,185	4,344,682	4,256,960	4,164,254	3,995,622
9	Commercial	NRH	3H	10,845	12,069	11,931	10,394	10,826
10	Commercial	CSH	4H	7,720	7,760	7,520	6,600	6,480
11	Industrial	IS	TCP	9,224,524	9,187,198	8,897,268	8,803,511	9,041,463
12	Industrial	IS	RCP	18,109,080	18,428,280	16,431,158	15,989,514	15,568,717
13	Public St. Lighting	MSL	MSL	203,547	119,398	71,086	68,077	64,798
14	Sales for Resale	EU	EU	86,672	89,564	90,549	94,767	102,572
15								
16	Adjusted Sales			102,357,893	103,796,496	101,458,230	97,458,516	97,019,287
17								
18	Schedule 1- RS			43,801,984	44,267,292	43,460,757	41,309,102	41,579,128
19	Schedule 2- RSAE			448,709	428,550	407,590	360,384	326,767
20	Schedule 3- NRS			4,214,185	4,344,682	4,256,960	4,164,254	3,995,622
21	Schedule 3- NRH			10,845	12,069	11,931	10,394	10,826
22	Schedule 4- CS			26,250,627	26,911,703	27,823,411	26,651,913	26,322,914
23	Schedule 4- CSH			7,720	7,760	7,520	6,600	6,480
24	Schedule 5- IS			27,333,604	27,615,478	25,328,426	24,793,025	24,610,180
25	Schedule 6- MSL			203,547	119,398	71,086	68,077	64,798
26	Schedule 7- POL							
27	Schedule 8- Resale			86,672	89,564	90,549	94,767	102,572
28				102,357,893	103,796,496	101,458,230	97,458,516	97,019,287
29	**Adjusted for POL**							

Wellsboro Electric Company
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Historic Sales and Revenue

	KWh	Actual	Actual	Actual	Actual	Actual
2	Rate Class	2020	2021	2022	2023	2024
30	Schedule 1- RS	43,801,984	44,267,292	43,460,757	41,309,102	41,579,128
31	Schedule 2- RSAE	448,709	428,550	407,590	360,384	326,767
32	Schedule 3- NRS	4,214,185	4,344,682	4,256,960	4,164,254	3,995,622
33	Schedule 3- NRH	10,845	12,069	11,931	10,394	10,826
34	Schedule 4- CS	26,250,627	26,911,703	27,823,411	26,651,913	26,322,914
35	Schedule 4- CSH	7,720	7,760	7,520	6,600	6,480
36	Schedule 5- IS	27,333,604	27,615,478	25,328,426	24,793,025	24,610,180
37	Schedule 6- MSL	203,547	119,398	71,086	68,077	64,798
38	Schedule 7- POL	-	-	-	-	-
39	Schedule 8- Resale	86,672	89,564	90,549	94,767	102,572
40		102,357,893	103,796,496	101,458,230	97,458,516	97,019,287
41						

	Customers	Actual	Actual	Actual	Actual	Actual	Average Change
43	Rate Class	2020	2021	2022	2023	2024	2020-2024
44	Schedule 1- RS	5,083	5,089	5,099	5,117	5,130	11.69
45	Schedule 2- RSAE	35	35	34	32	30	(1.29)
46	Schedule 3- NRS	862	877	890	898	908	11.54
47	Schedule 3- NRH	2	2	2	2	1	(0.19)
48	Schedule 4- CS	365	365	369	375	381	4.04
49	Schedule 4- CSH	1	1	1	1	1	-
50	Schedule 5- IS	12	12	12	12	13	0.25
51	Schedule 6- MSL	2	2	2	2	2	-
52	Schedule 7- POL						-
53	Schedule 8- Resale	4	4	4	4	4	-
54		6,365	6,387	6,414	6,443	6,470	
55							
56		6,365	6,387	6,414	6,443	6,470	6,470

57	**Annual kWh Per Customer**	Actual	Actual	Actual	Actual	Actual	Average	
58	Rate Class	2020	2021	2022	2023	2024	2020-2024	
59	Schedule 1- RS	8,617	8,698	8,524	8,074	8,106	8,404	
60	Schedule 2- RSAE	12,820	12,244	11,872	11,175	10,953	11,813	
61	Schedule 3- NRS	4,891	4,957	4,783	4,640	4,402	4,734	
62	Schedule 3- NRH	5,423	6,035	5,966	5,197	8,661	6,256	
63	Schedule 4- CS	71,936	73,680	75,368	71,040	69,074	72,220	
64	Schedule 4- CSH	7,720	7,760	7,520	6,600	6,480	7,216	
65	Schedule 5- IS	2,277,800	2,301,290	2,110,702	2,037,783	1,893,091	2,124,133	
66	Schedule 6- MSL	101,774	59,699	35,543	34,039	32,399	33,219	
67	Schedule 7- POL							
68	Schedule 8- Resale	21,668	22,391	22,637	23,692	25,643	23,206	
69	AVERAGE	16,080	16,251	15,819	15,127	14,996	15,655	103,979,075

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Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026 (R)
Historic Billing Units

Line		2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
1	**Revenue Class 1 -- RURAL LIGHTING --RL-- 440 -- KWH**										
3	January	3,161,519	2,935,136	3,139,576	3,357,329	3,151,484	3,043,879	3,283,484	3,113,354	3,200,011	2,878,005
4	February	3,211,927	2,918,766	2,902,775	3,149,624	3,123,815	2,807,085	3,186,289	3,245,674	2,766,154	2,775,040
5	March	2,946,260	2,663,575	2,481,834	2,507,100	2,727,338	2,605,645	2,704,875	2,724,029	2,461,980	2,563,062
6	April	2,690,395	2,405,114	2,522,037	2,644,636	2,445,456	2,665,004	2,544,499	2,688,994	2,542,964	2,408,971
7	May	2,111,259	2,127,732	2,016,139	2,187,274	2,195,696	2,347,606	2,149,950	2,204,172	2,082,434	2,060,811
8	June	2,203,939	2,253,570	2,228,671	2,158,827	2,112,144	2,385,198	2,297,291	2,212,222	2,143,480	2,181,632
9	July	2,274,437	2,350,610	2,338,815	2,497,216	2,362,861	2,757,782	2,709,558	2,481,546	2,374,668	2,789,297
10	August	2,453,375	2,785,153	2,540,400	2,584,505	2,796,115	2,928,181	2,683,291	2,825,226	2,566,227	2,687,911
11	September	2,399,923	2,502,916	2,183,484	2,578,007	2,278,558	2,487,143	2,669,092	2,522,760	2,519,078	2,459,982
12	October	2,103,979	2,079,680	2,147,272	2,137,254	2,157,585	2,196,001	2,311,864	2,103,672	1,970,478	2,048,006
13	November	2,309,053	2,345,908	2,405,425	2,616,659	2,389,398	2,356,150	2,385,049	2,236,649	2,210,981	2,339,080
14	December	2,642,340	2,771,804	2,799,380	2,952,116	2,765,509	2,745,077	2,807,872	2,778,191	2,789,039	2,668,152
15		30,508,406	30,139,964	29,705,808	31,370,547	30,505,959	31,324,751	31,733,114	31,136,489	29,627,494	29,859,949
16											
17	**Revenue Class 5 -- TOWN LIGHTING --TL -- 440 -- KWH**										
18	January	1,107,471	1,041,669	1,066,256	1,159,362	1,075,855	1,050,980	1,186,861	1,087,977	1,207,074	1,024,591
19	February	1,163,775	1,046,673	1,040,921	1,184,832	1,164,467	1,030,794	1,086,561	1,188,065	995,972	1,018,510
20	March	1,100,269	951,353	855,472	914,609	947,416	915,263	1,005,541	1,007,878	886,045	985,314
21	April	988,837	862,263	1,000,365	945,674	950,265	885,828	984,327	978,015	930,988	852,411
22	May	751,298	750,145	696,125	804,674	711,427	876,033	710,715	782,788	722,491	747,134
23	June	761,071	747,600	748,802	760,684	738,607	774,005	782,660	748,620	685,189	735,893
24	July	843,265	807,314	782,598	843,482	730,247	826,533	891,307	853,427	781,561	882,771
25	August	905,963	956,980	943,248	884,537	1,080,876	1,173,193	1,009,622	1,034,591	984,797	1,037,651
26	September	824,268	1,017,021	810,505	985,395	834,824	995,167	1,072,871	948,215	885,248	945,232
27	October	802,203	756,136	737,861	805,708	718,295	730,149	798,424	791,649	747,172	722,684
28	November	788,333	777,102	783,517	865,493	787,969	838,607	779,969	806,370	755,156	798,332
29	December	838,272	921,351	953,825	954,051	937,238	897,690	943,260	883,237	957,323	854,064
30		10,875,025	10,635,607	10,419,495	11,108,501	10,677,486	10,994,242	11,252,118	11,110,832	10,539,016	10,604,587
31											
32	**Revenue Class 4 -- RURAL FARM LIGHTING --RFL-- 440 -- KWH**										
33	January	184,025	167,299	178,155	181,666	156,686	149,598	140,567	115,836	119,863	109,229
34	February	192,149	172,601	169,604	177,334	158,482	138,241	143,788	137,167	101,924	109,210
35	March	177,102	167,148	145,599	140,956	142,741	124,593	119,970	112,570	90,153	99,030
36	April	161,469	150,874	151,411	145,784	131,402	126,673	108,961	105,807	95,048	93,758
37	May	142,281	141,226	130,327	136,769	125,800	109,750	88,310	88,698	83,252	84,343
38	June	148,507	150,248	144,871	137,670	125,786	121,873	89,583	86,559	85,017	83,679
39	July	154,676	156,152	144,980	149,530	129,779	130,078	103,615	90,511	89,102	98,533
40	August	159,268	174,204	156,327	153,689	150,343	133,382	104,686	103,807	100,902	96,275
41	September	156,641	164,276	140,657	152,029	134,698	120,855	97,499	100,506	100,106	87,004
42	October	134,131	143,411	136,056	133,093	126,044	109,188	93,803	80,959	78,831	77,048
43	November	139,587	142,296	140,208	142,567	124,381	103,220	87,960	88,221	88,341	86,582
44	December	150,907	155,820	157,059	147,252	141,112	115,540	103,318	102,795	110,053	89,901
45		1,900,743	1,885,555	1,795,254	1,798,339	1,647,254	1,482,991	1,282,060	1,213,436	1,142,592	1,114,592
46											

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Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026 (R)
Historic Billing Units

Line

Revenue Class 1 -- RURAL LIGHTING --RL-- 440 -- KWH

Line			2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
47	**Revenue Class 2 -- RURAL COMMERCIAL POWER--RCP -- 442.01 -- KWH**											
48	January		1,760,220	1,963,860	1,633,620	1,371,120	1,725,840	1,690,860	1,508,160	1,401,600	1,497,595	1,330,754
49	February		1,726,980	1,954,680	1,828,500	1,603,656	1,560,600	1,498,080	1,565,040	1,236,120	1,449,254	1,289,709
50	March		1,634,520	2,204,460	1,738,500	1,465,504	1,472,100	1,507,920	1,540,500	1,471,320	1,309,458	1,199,848
51	April		1,835,280	1,943,400	1,860,420	1,565,940	1,574,520	1,685,100	1,741,320	1,463,280	1,391,404	1,352,119
52	May		1,933,980	1,950,000	1,814,520	1,678,860	1,763,160	1,242,540	1,493,940	1,398,780	1,336,606	1,315,240
53	June		1,996,560	1,994,040	1,994,040	1,767,780	1,548,960	1,301,100	1,636,500	1,396,740	1,426,037	1,476,249
54	July		2,055,960	1,838,940	1,754,760	1,711,860	1,734,900	1,661,160	1,737,900	1,296,540	1,289,359	1,275,781
55	August		1,885,980	1,962,660	1,836,720	1,733,520	1,726,320	1,555,740	1,600,680	1,433,760	1,469,258	1,259,193
56	September		1,863,120	2,002,860	1,619,700	1,376,100	1,449,960	1,555,320	1,411,560	1,357,920	1,207,566	1,155,949
57	October		1,909,500	1,778,460	1,581,000	1,387,560	1,454,820	1,358,340	1,357,260	1,175,580	1,163,562	1,192,411
58	November		1,777,860	1,749,840	1,444,200	1,283,820	1,531,320	1,473,120	1,348,920	1,358,160	1,152,854	1,329,544
59	December		1,790,220	1,748,100	1,334,928	1,445,220	1,509,720	1,579,800	1,486,500	1,441,358	1,296,561	1,391,920
60			22,170,180	23,091,300	20,440,908	18,390,940	19,052,220	18,109,080	18,428,280	16,431,158	15,989,514	15,568,717
61												
62	**Revenue Class 3 -- RURAL COMMERCIAL LIGHTING--RCL-- 442 -- KWH**											
63	January		454,244	394,224	425,486	433,834	403,841	414,577	422,748	410,015	419,661	376,362
64	February		476,844	441,730	416,972	440,874	443,586	407,453	427,854	455,252	388,697	377,435
65	March		449,108	417,123	380,715	393,329	404,479	388,460	395,576	392,746	375,856	382,289
66	April		448,698	403,217	398,615	413,367	417,636	372,917	405,699	415,534	389,775	351,486
67	May		330,895	329,662	304,773	339,684	326,891	293,808	305,812	317,078	304,862	297,715
68	June		341,781	340,824	330,672	332,836	315,745	303,214	318,330	303,453	307,735	304,800
69	July		356,154	351,714	345,214	354,436	330,606	341,038	354,418	325,623	315,194	340,121
70	August		393,436	397,191	376,535	356,788	403,089	369,571	365,108	353,681	346,972	335,369
71	September		345,311	377,082	320,313	357,171	335,755	336,173	354,153	338,543	337,127	319,700
72	October		321,864	319,091	304,561	314,522	318,533	302,795	312,641	300,177	290,167	281,482
73	November		323,648	330,428	319,427	349,931	328,253	333,072	314,385	297,836	312,575	304,376
74	December		352,371	371,762	367,609	384,296	384,092	351,107	367,958	347,022	375,633	324,487
75		TC	4,594,354	4,474,048	4,290,892	4,471,068	4,412,506	4,214,185	4,344,682	4,256,960	4,164,254	3,995,622
76												

Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026 (R)
Historic Billing Units

Line			2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
1		**Revenue Class 1 -- RURAL LIGHTING --RL-- 440 -- KWH**										
2												
77		**Revenue Class 6 -- TOWN COMMERCIAL POWER --TCP -- 442.01 -- KWH**										
78	January		1,701,880	1,852,620	727,280	787,940	788,043	773,476	696,501	699,164	691,334	698,575
79	February		1,756,000	1,774,800	727,400	732,081	752,783	699,207	690,371	675,658	644,161	695,233
80	March		1,599,460	1,886,760	696,640	749,959	718,559	707,962	686,382	673,360	632,122	664,603
81	April		1,599,960	1,676,480	764,340	799,909	699,196	697,919	704,901	660,693	673,135	713,890
82	May		1,833,600	1,748,460	750,480	756,471	806,907	687,793	710,716	719,965	691,214	735,645
83	June		1,931,880	1,907,700	896,020	871,950	821,053	818,324	829,985	840,786	800,200	863,541
84	July		1,889,360	1,963,240	944,560	905,070	972,636	953,553	918,672	892,202	862,536	939,350
85	August		1,906,140	1,793,800	954,400	968,287	942,863	894,980	898,791	918,521	924,601	894,347
86	September		1,987,820	1,719,040	841,540	858,384	832,837	817,330	864,010	834,907	835,283	772,826
87	October		1,926,700	1,070,740	824,100	815,437	779,387	759,716	806,048	672,450	721,456	719,113
88	November		1,740,340	799,900	729,920	731,626	755,617	700,167	657,049	656,835	667,792	704,465
89	December		1,691,120	775,500	752,363	752,410	773,655	714,097	723,772	652,727	659,677	639,875
90		TC	21,564,260	18,969,040	9,609,043	9,729,524	9,643,536	9,224,524	9,187,198	8,897,268	8,803,511	9,041,463
91												
92		**Revenue Class 7 -- TOWN COMMERCIAL LIGHTING -- TCL --442 -- KWH**										
93	January		2,521,053	2,327,347	2,521,517	2,532,921	2,503,929	2,408,661	2,343,715	2,402,873	2,561,604	2,368,626
94	February		2,617,925	2,377,544	2,530,811	2,679,357	2,621,862	2,417,080	2,391,324	2,613,728	2,358,165	2,344,982
95	March		2,460,840	2,252,862	2,190,274	2,192,021	2,319,703	2,214,704	2,210,154	2,231,882	2,153,322	2,355,081
96	April		2,386,201	2,221,045	2,389,658	2,319,301	2,248,644	2,116,593	2,244,717	2,308,679	2,251,674	2,137,912
97	May		2,121,754	2,051,801	2,020,998	2,135,284	2,007,788	1,823,700	1,860,821	1,993,016	1,960,657	1,904,008
98	June		2,303,789	2,264,560	2,254,726	2,214,001	2,170,127	1,870,660	2,109,960	2,160,503	2,070,781	2,108,065
99	July		2,320,066	2,340,983	2,308,740	2,424,726	2,165,801	2,218,217	2,328,523	2,544,960	2,144,124	2,288,585
100	August		2,460,835	2,654,681	2,649,972	2,538,411	2,711,557	2,572,413	2,482,890	2,549,734	2,380,908	2,327,700
101	September		2,335,691	2,653,053	2,286,069	2,582,990	2,312,090	2,337,646	2,519,022	2,396,487	2,266,112	2,272,314
102	October		2,219,728	2,182,010	2,250,965	2,209,054	2,177,376	2,056,659	2,164,737	2,137,824	2,010,947	2,005,363
103	November		2,124,762	2,365,179	2,223,503	2,364,928	2,130,658	2,144,907	2,111,992	2,232,724	2,164,321	2,134,430
104	December		2,119,019	2,335,679	2,274,114	2,229,952	2,207,496	2,069,387	2,143,848	2,251,001	2,329,298	2,075,848
105		TC	27,991,663	28,026,744	27,901,347	28,422,946	27,577,031	26,250,627	26,911,703	27,823,411	26,651,913	26,322,914
106												
107		**Revenue Class 9 -- PUBLIC MUNICIPAL STREET LIGHTING -- 444 -- KWH**										
108	January		18,333	17,853	17,728	19,828	19,826	19,342	14,669	6,210	5,782	5,519
109	February		18,283	17,803	17,728	19,828	19,826	19,182	13,016	6,203	5,782	5,389
110	March		18,283	17,778	17,728	19,828	19,826	18,794	12,434	6,203	5,782	5,389
111	April		18,283	17,778	19,828	19,828	19,826	17,130	12,008	5,996	5,782	5,389
112	May		18,258	17,778	19,828	19,896	19,826	17,130	12,008	5,841	5,782	5,389
113	June		18,278	17,753	19,828	19,896	19,826	17,130	10,567	5,841	5,600	5,389
114	July		18,253	17,753	19,828	19,826	19,826	16,936	9,997	5,841	5,600	5,389
115	August		18,203	17,753	19,828	19,826	19,826	16,659	8,429	5,841	5,600	5,389
116	September		18,178	17,753	19,828	19,826	19,747	15,862	7,503	5,789	5,600	5,389
117	October		18,433	17,753	19,828	19,826	19,657	15,282	6,347	5,757	5,589	5,389
118	November		18,028	17,728	19,828	19,826	19,612	15,050	6,210	5,782	5,589	5,389
119	December		17,953	17,728	19,828	19,826	19,567	15,050	6,210	5,782	5,589	5,389
120		TC	218,766	213,211	231,636	238,060	237,191	203,547	119,398	71,086	68,077	64,798
121												

Line			2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
1			**Revenue Class 1 -- RURAL LIGHTING --RL-- 440 -- KWH**									
122			**Revenue Class 8 -- SALES FOR RESALES -- 447 -- REVENUE**									
123	January		10,011	7,476	13,065	9,851	9,862	7,369	10,440	8,248	7,615	8,415
124	February		12,177	11,762	10,010	7,485	8,172	7,710	8,981	9,937	7,077	8,654
125	March		9,589	9,803	9,083	7,802	7,588	6,733	7,141	7,352	6,723	7,983
126	April		9,068	8,717	9,570	10,213	6,872	5,585	6,809	7,566	6,495	8,201
127	May		8,059	5,431	7,090	7,312	5,707	6,117	6,206	6,348	7,051	7,694
128	June		8,695	10,512	7,767	7,988	7,642	6,237	6,874	6,948	6,542	8,191
129	July		8,247	9,053	7,594	8,159	7,107	7,298	7,397	7,737	8,956	8,790
130	August		9,053	7,856	7,270	6,845	7,498	7,722	6,194	6,945	8,295	8,426
131	September		8,274	9,259	6,431	7,659	7,533	7,802	7,081	6,806	9,159	7,922
132	October		8,790	8,174	8,790	8,422	5,970	6,443	5,820	6,379	6,486	7,068
133	November		10,382	10,168	7,388	8,613	7,865	7,927	7,381	7,215	8,192	9,268
134	December		13,128	16,806	12,946	17,974	11,419	9,729	9,240	9,068	12,176	11,960
135			115,473	115,017	107,004	108,323	93,235	86,672	89,564	90,549	94,767	102,572
136												
137			**Revenue Class 11 -- 3H SCH-HEAT -- RCL -- 442 -- KWH**									
138	January		3,091	1,055	3,273	3,696	1,310	1,550	1,248	863	1,630	801
139	February		4,048	1,827	3,392	2,595	2,361	1,846	1,601	2,316	1,272	1,548
140	March		4,124	2,415	2,545	782	1,493	1,621	1,812	1,494	1,164	2,020
141	April		2,051	1,447	3,033	1,020	1,169	706	770	1,160	1,061	1,533
142	May		907	1,299	766	678	493	503	315	592	535	434
143	June		736	607	1,058	981	641	345	462	731	376	549
144	July		685	640	941	1,076	784	679	835	995	818	750
145	August		831	783	1,064	1,131	1,014	972	908	1,068	1,140	748
146	September		832	856	821	1,192	903	980	1,212	881	833	725
147	October		633	1,049	864	977	859	796	1,085	738	598	680
148	November		728	808	838	857	632	465	810	521	419	591
149	December		830	2,098	1,968	1,045	963	382	1,011	572	548	447
150		TC	19,496	14,884	20,563	16,030	12,622	10,845	12,069	11,931	10,394	10,826
151												
152			**Revenue Class 12 -- 4H CSH-HEAT -- TCL -- 442 -- KWH**									
153	January		4,880	1,040	640	480	680	520	560	520	600	440
154	February		4,400	640	720	680	480	560	560	600	480	520
155	March		4,240	680	440	520	520	480	560	480	400	520
156	April		3,160	760	720	640	600	560	520	520	560	480
157	May		1,040	480	480	560	480	360	320	440	400	400
158	June		680	680	600	920	640	480	480	440	440	480
159	July		840	840	1,040	1,240	760	920	880	960	640	760
160	August		1,200	1,160	1,120	1,360	1,600	1,480	1,040	1,240	960	1,000
161	September		840	1,480	880	1,720	1,040	1,160	1,520	1,160	800	680
162	October		840	720	680	720	640	520	560	520	560	520
163	November		920	440	400	400	440	320	400	280	320	280
164	December		1,400	600	520	520	480	360	360	360	440	400
165		TC	24,440	9,520	8,240	9,760	8,360	7,720	7,760	7,520	6,600	6,480

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Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026 (R)
Historic Billing Units

Line

1 **Revenue Class 1 -- RURAL LIGHTING --RL-- 440 -- KWH**

2		2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
166											
167	**Revenue Class 13 -- 2-RSAE -- ALL ELECTRIC -- RL/TL --440 -- KWH**										
168	January	80,994	61,892	71,130	69,473	59,790	56,346	54,348	50,304	53,596	38,400
169	February	91,191	69,959	66,215	64,920	65,842	54,434	54,236	60,310	46,549	40,881
170	March	87,925	63,023	51,407	47,276	53,891	50,216	46,753	49,731	41,043	39,302
171	April	70,268	50,197	54,197	49,821	47,608	44,186	40,036	44,380	40,036	33,270
172	May	41,405	41,550	31,774	38,695	30,951	40,178	28,818	29,501	25,632	24,157
173	June	31,803	32,017	31,047	25,344	24,854	29,068	26,171	19,791	20,698	18,334
174	July	30,755	28,971	26,731	26,364	23,455	25,345	25,511	21,285	18,961	19,650
175	August	30,434	31,678	28,873	26,701	29,544	28,128	26,685	23,193	20,284	19,535
176	September	29,774	30,516	26,781	27,767	25,190	24,864	27,153	21,828	19,649	19,350
177	October	32,097	28,738	26,306	25,912	25,321	23,805	24,887	21,403	16,831	16,729
178	November	42,967	37,944	36,618	40,600	34,267	31,724	31,164	27,088	22,535	25,219
179	December	51,279	55,094	54,279	54,550	50,495	40,415	42,788	38,776	34,570	31,940
180		620,892	531,579	505,358	497,423	471,208	448,709	428,550	407,590	360,384	326,767
181											
182		**2015 ACTUAL**	**2016 ACTUAL**	**2017 ACTUAL**	**2018 ACTUAL**						
183	January	11,007,721	10,771,471	9,797,726	9,927,500	9,897,146	9,617,158	9,663,301	9,296,964	9,766,365	8,839,717
184	February	11,275,699	10,788,785	9,715,048	10,063,266	9,922,276	9,081,672	9,569,621	9,631,030	8,765,487	8,667,111
185	March	10,491,720	10,636,980	8,570,237	8,439,686	8,815,654	8,542,391	8,731,698	8,679,045	7,964,048	8,304,441
186	April	10,213,670	9,741,292	9,174,194	8,916,133	8,543,194	8,618,201	8,794,567	8,680,624	8,328,922	7,959,420
187	May	9,294,736	9,165,564	7,793,300	8,106,157	7,995,126	7,445,518	7,367,931	7,547,219	7,220,916	7,182,970
188	June	9,747,719	9,720,111	8,658,102	8,298,877	7,886,025	7,627,634	8,108,863	7,782,634	7,552,095	7,786,802
189	July	9,952,698	9,866,210	8,675,801	8,942,985	8,478,762	8,939,539	9,088,613	8,521,627	7,891,519	8,649,777
190	August	10,224,718	10,783,899	9,515,757	9,275,600	9,870,645	9,682,421	9,188,324	9,257,607	8,809,944	8,673,544
191	September	9,970,672	10,496,112	8,257,009	8,948,240	8,233,135	8,700,302	9,032,676	8,535,802	8,186,561	8,047,073
192	October	9,478,898	8,385,962	8,038,283	7,858,485	7,784,487	7,559,694	7,883,476	7,297,108	7,012,677	7,076,493
193	November	9,276,608	8,577,741	8,111,272	8,425,320	8,110,412	8,004,729	7,731,289	7,717,681	7,389,075	7,737,556
194	December	9,668,839	9,172,342	8,728,819	8,959,212	8,801,746	8,538,634	8,636,137	8,510,889	8,570,907	8,094,383
195	TC	120,603,698	118,106,469	105,035,548	106,161,461	104,338,608	102,357,893	103,796,496	101,458,230	97,458,516	97,019,287

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Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026 (R)
Customer Counts

Line		2019	2020	2021	2022	2023	2024
1							
2							
3	January	3,519	3,518	3,524	3,533	3,552	3,562
4	February	3,519	3,521	3,525	3,532	3,548	3,561
5	March	3,519	3,523	3,527	3,532	3,549	3,561
6	April	3,519	3,524	3,523	3,533	3,549	3,563
7	May	3,514	3,522	3,528	3,535	3,558	3,566
8	June	3,520	3,527	3,530	3,535	3,555	3,569
9	July	3,520	3,529	3,529	3,533	3,555	3,576
10	August	3,519	3,535	3,533	3,535	3,558	3,575
11	September	3,518	3,530	3,531	3,542	3,556	3,574
12	October	3,522	3,530	3,530	3,547	3,557	3,578
13	November	3,521	3,524	3,531	3,548	3,560	3,568
14	December	3,520	3,526	3,535	3,552	3,562	3,566
15		42,230	42,309	42,346	42,457	42,659	42,819
16							
17							
18	January	1,475	1,467	1,474	1,475	1,480	1,482
19	February	1,475	1,467	1,473	1,475	1,480	1,481
20	March	1,474	1,466	1,472	1,476	1,480	1,482
21	April	1,470	1,467	1,474	1,476	1,480	1,483
22	May	1,469	1,468	1,474	1,476	1,479	1,483
23	June	1,468	1,467	1,474	1,477	1,478	1,484
24	July	1,467	1,468	1,476	1,477	1,478	1,484
25	August	1,466	1,467	1,477	1,477	1,479	1,483
26	September	1,465	1,472	1,477	1,478	1,478	1,483
27	October	1,467	1,471	1,476	1,478	1,478	1,483
28	November	1,467	1,471	1,476	1,478	1,479	1,483
29	December	1,468	1,474	1,474	1,479	1,481	1,483
30		17,631	17,625	17,697	17,722	17,750	17,794
31							
32	**Re**						
33	January	91	90	87	84	84	80
34	February	91	90	87	84	84	80
35	March	91	89	87	84	84	80
36	April	91	89	87	84	83	79
37	May	91	89	86	84	82	78
38	June	91	89	85	84	82	78
39	July	91	89	85	84	82	78
40	August	90	88	85	84	82	78
41	September	90	87	85	84	82	78
42	October	90	87	85	84	82	78
43	November	90	87	85	84	82	78
44	December	90	87	85	84	80	78
45		1,087	1,061	1,029	1,008	989	943
46							

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Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026 (R)
Customer Counts

Line			2019	2020	2021	2022	2023	2024
47		**Re**						
48	January		6	6	6	6	6	7
49	February		6	6	6	6	6	7
50	March		6	6	6	6	6	7
51	April		6	6	6	6	6	7
52	May		6	6	6	6	6	7
53	June		6	6	6	6	6	7
54	July		6	6	6	6	6	7
55	August		5	6	6	6	6	7
56	September		6	6	6	6	6	7
57	October		6	6	6	6	6	7
58	November		6	6	6	6	7	7
59	December		6	6	6	6	7	7
60			71	72	72	72	74	84
61								
62		**Re**						
63	January		840	855	874	885	893	901
64	February		841	854	875	886	895	901
65	March		843	853	877	887	897	903
66	April		845	855	876	887	897	904
67	May		844	858	876	889	896	910
68	June		844	860	876	891	897	909
69	July		844	866	877	884	893	911
70	August		846	862	875	894	900	912
71	September		846	867	876	895	900	911
72	October		848	867	876	895	901	910
73	November		848	869	879	894	900	910
74	December		850	873	881	894	901	911
75		TC	10,139	10,339	10,518	10,681	10,770	10,893
76								

Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026 (R)
Customer Counts

Line			2019	2020	2021	2022	2023	2024
1								
2								
77		**Re**						
78	January		6	6	6	6	6	6
79	February		6	6	6	6	6	6
80	March		6	6	6	6	6	6
81	April		6	6	6	6	6	6
82	May		6	6	6	6	6	6
83	June		6	6	6	6	6	6
84	July		6	6	6	6	6	6
85	August		6	6	6	6	6	6
86	September		6	6	6	6	6	6
87	October		6	6	6	6	6	6
88	November		6	6	6	6	6	6
89	December		6	6	6	6	6	6
90		TC	72	72	72	72	72	72
91								
92		**Re**						
93	January		359	363	365	365	370	379
94	February		359	364	364	366	371	381
95	March		358	364	364	368	371	381
96	April		362	363	363	368	373	382
97	May		360	363	365	368	373	379
98	June		360	366	365	370	375	379
99	July		360	366	367	376	381	380
100	August		360	370	367	370	377	380
101	September		358	365	366	369	377	381
102	October		361	365	366	370	376	382
103	November		363	365	365	370	379	384
104	December		362	365	366	370	379	385
105		TC	4,322	4,379	4,383	4,430	4,502	4,573
106								
107		**Re**						
108	January		2	2	2	2	2	2
109	February		2	2	2	2	2	2
110	March		2	2	2	2	2	2
111	April		2	2	2	2	2	2
112	May		2	2	2	2	2	2
113	June		2	2	2	2	2	2
114	July		2	2	2	2	2	2
115	August		2	2	2	2	2	2
116	September		2	2	2	2	2	2
117	October		2	2	2	2	2	2
118	November		2	2	2	2	2	2
119	December		2	2	2	2	2	2
120		TC	24	24	24	24	24	24
121								

Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026 (R)
Customer Counts

Line			2019	2020	2021	2022	2023	2024
1								
2								
122								
123	January		4	4	4	4	4	4
124	February		4	4	4	4	4	4
125	March		4	4	4	4	4	4
126	April		4	4	4	4	4	4
127	May		4	4	4	4	4	4
128	June		4	4	4	4	4	4
129	July		4	4	4	4	4	4
130	August		4	4	4	4	4	4
131	September		4	4	4	4	4	4
132	October		4	4	4	4	4	4
133	November		4	4	4	4	4	4
134	December		4	4	4	4	4	4
135			48	48	48	48	48	48
136								
137		**Re**						
138	January		2	2	2	2	2	2
139	February		2	2	2	2	2	2
140	March		2	2	2	2	2	2
141	April		2	2	2	2	2	1
142	May		2	2	2	2	2	1
143	June		2	2	2	2	2	1
144	July		2	2	2	2	2	1
145	August		2	2	2	2	2	1
146	September		2	2	2	2	2	1
147	October		2	2	2	2	2	1
148	November		2	2	2	2	2	1
149	December		2	2	2	2	2	1
150		TC	24	24	24	24	24	15
151								
152		**Re**						
153	January		1	1	1	1	1	1
154	February		1	1	1	1	1	1
155	March		1	1	1	1	1	1
156	April		1	1	1	1	1	1
157	May		1	1	1	1	1	1
158	June		1	1	1	1	1	1
159	July		1	1	1	1	1	1
160	August		1	1	1	1	1	1
161	September		1	1	1	1	1	1
162	October		1	1	1	1	1	1
163	November		1	1	1	1	1	1
164	December		1	1	1	1	1	1
165		TC	12	12	12	12	12	12

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Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026 (R)
Customer Counts

Line			2019	2020	2021	2022	2023	2024
1								
2								
166								
167								
168	January		37	35	35	35	33	31
169	February		37	35	35	35	33	31
170	March		37	35	35	35	33	31
171	April		36	35	35	35	33	30
172	May		36	35	35	35	33	30
173	June		36	35	35	35	33	30
174	July		36	35	35	35	33	30
175	August		36	35	35	34	32	29
176	September		35	35	35	34	31	29
177	October		35	35	35	33	31	29
178	November		35	35	35	33	31	29
179	December		35	35	35	33	31	29
180			431	420	420	412	387	358
181								
182								
183	January		6,342	6,349	6,380	6,398	6,433	6,457
184	February		6,343	6,352	6,380	6,399	6,432	6,457
185	March		6,343	6,351	6,383	6,403	6,435	6,460
186	April		6,344	6,354	6,379	6,404	6,436	6,462
187	May		6,335	6,356	6,385	6,408	6,442	6,467
188	June		6,340	6,365	6,386	6,413	6,441	6,470
189	July		6,339	6,374	6,390	6,410	6,443	6,480
190	August		6,337	6,378	6,393	6,415	6,449	6,478
191	September		6,333	6,377	6,391	6,423	6,445	6,477
192	October		6,344	6,376	6,389	6,428	6,446	6,481
193	November		6,345	6,372	6,392	6,428	6,453	6,473
194	December		6,346	6,381	6,397	6,433	6,456	6,473
195		TC	76,091	76,385	76,645	76,962	77,311	77,635

Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026 (R)
Sales Recap
Period Ending December 31, 2024

Line	SC	Customer Class	Type	January	February	March	April	May	June	July	August	September	October	November	December	Totals
1	1	1-RL	D	214,817	208,780	196,332	187,288	166,871	174,064	209,730	203,802	190,504	166,278	183,403	202,569	2,304,439
2	1	1-RL-STAS	S	(49)	(47)	(44)	(42)	(37)	(36)	(44)	(43)	(40)	(34)	(38)	(46)	(499)
3	1	1-RL-GEN	G	265,322	255,828	236,288	222,082	189,986	177,430	226,852	218,606	200,069	166,563	190,236	243,734	2,592,996
4	1	1-RFL	D	7,622	7,621	7,024	6,715	6,151	6,100	6,978	6,839	6,295	5,706	6,270	6,465	79,786
5	1	1-RFL-STAS	S	(2)	(2)	(2)	(2)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(18)
6	1	1-RFL-GEN	G	10,070	10,068	9,130	8,643	7,776	6,805	8,014	7,830	7,076	6,266	7,042	8,212	96,931
7	1	1-TL	D	78,197	77,838	75,883	68,084	61,909	61,273	69,907	78,991	73,564	60,511	64,943	68,218	839,318
8	1	1-TL-STAS	S	(18)	(18)	(17)	(15)	(14)	(12)	(15)	(17)	(15)	(12)	(13)	(15)	(181)
9	1	1-TL-GEN	G	94,457	93,896	90,836	78,584	68,878	59,850	71,796	84,392	76,876	58,776	64,928	78,019	921,288
10	2	2-RSAE - RL/TL	D	2,371	2,498	2,417	2,108	1,632	1,330	1,397	1,384	1,370	1,236	1,671	2,016	21,430
11	2	2-RSAE - RL/TL - ST/	S	(1)	(1)	(1)	(1)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(1)	(5)
12	2	2-RSAE - RL/TL - GE	G	3,540	3,769	3,623	3,067	2,227	1,491	1,598	1,589	1,574	1,361	2,051	2,918	28,807
13	3	3-RCL	D	40,591	40,672	41,060	38,716	34,724	35,285	37,933	37,534	36,412	33,490	35,221	36,750	448,390
14	3	3-RCL-STAS	S	(7)	(7)	(7)	(6)	(5)	(5)	(6)	(6)	(5)	(5)	(5)	(6)	(72)
15	3	3-RCL-GEN	G	33,488	33,632	34,103	31,305	26,419	23,853	26,761	26,375	25,065	22,077	23,925	28,801	335,804
16	3H	3H-Sch Heat - RCL	D	92	156	196	154	49	59	76	76	74	70	62	50	1,112
17	3H	3H-Sch Heat - RCL -	S	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
18	3H	3H-Sch Heat - RCL -	G	74	143	186	141	40	45	61	61	59	55	48	41	954
19	4	4-TCL	D	120,732	121,897	119,458	113,857	109,999	117,659	124,818	126,185	122,958	115,185	116,954	115,003	1,424,706
20	4	4-TCL - STAS	S	(29)	(29)	(28)	(26)	(24)	(25)	(27)	(28)	(27)	(25)	(26)	(27)	(319)
21	4	4-TCL - GEN	G	159,476	158,058	156,153	139,557	123,851	125,035	140,085	145,484	142,473	127,518	135,353	147,699	1,700,741
22	4H	4H-CSH Heat - TCL	D	75	80	80	78	72	78	96	112	91	80	64	72	979
23	4H	4H-CSH Heat - TCL -	S	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
24	4H	4H-CSH Heat - TCL -	G	41	48	48	44	37	39	62	81	55	42	23	37	557
25	5	5-RCP	D	42,207	42,747	41,958	42,411	43,628	45,376	46,185	46,333	45,882	43,897	42,211	42,475	525,311
26	5	5-RCP - STAS	S	(7)	(7)	(7)	(7)	(7)	(8)	(9)	(8)	(8)	(8)	(7)	(7)	(91)
27	5	5-RCP - GEN	G	33,632	34,457	26,853	29,187	29,967	34,155	40,118	36,587	29,644	31,879	30,146	31,061	387,686
28	5	5-TCP	D	19,414	20,194	20,997	21,498	22,355	25,088	25,389	25,258	24,365	24,006	20,915	19,204	268,684
29	5	5-TCP - STAS	S	(6)	(6)	(6)	(6)	(6)	(8)	(9)	(8)	(7)	(7)	(7)	(7)	(84)
30	5	5-TCP -GEN	G	44,143	42,863	39,229	43,466	43,700	55,006	68,794	59,909	48,669	49,432	45,845	49,172	590,226
31	6	6-ML - Public Street I	D	1,127	1,121	1,121	1,121	1,121	1,121	1,121	1,121	1,121	1,121	1,121	1,121	13,458
32	6	6-ML PSL - STAS	S	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(2)
33	6	6-ML PSL - GEN	G	508	496	496	496	496	437	437	437	437	437	437	491	5,609
34																
35	8	8-EU - Sales for Resa	D	735	756	697	716	672	715	768	736	692	617	809	1,044	8,957
36	8	8-EU - Sales for Resa	G	776	798	736	756	709	666	715	685	644	575	754	1,093	8,907
37		Totals Sales Revenue		1,173,389	1,158,300	1,104,792	1,039,970	943,176	952,865	1,109,579	1,110,294	1,035,863	917,086	974,336	1,086,155	12,605,806
38																
39		Distribution		527,981	524,361	507,223	482,745	449,184	468,149	524,398	528,370	503,327	452,197	473,647	494,987	5,936,569
40		STAS		(118)	(117)	(112)	(105)	(95)	(96)	(111)	(112)	(104)	(92)	(99)	(110)	(1,270)
41		Generation		645,526	634,056	597,681	557,330	494,086	484,812	585,293	582,035	532,641	464,981	500,788	591,278	6,670,507
42		Total Sales Revenue		1,173,389	1,158,300	1,104,792	1,039,970	943,176	952,865	1,109,579	1,110,294	1,035,863	917,086	974,336	1,086,155	12,605,806
43																12,607,075

Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026 (R)
Sales Recap
Period Ending December 31, 2024

Line	SC	Customer Class / kWh Generation	Type	January	February	March	April	May	June	July	August	September	October	November	December	Totals
44				January	February	March	April	May	June	July	August	September	October	November	December	Totals
45		Residential		4,050,225	3,943,641	3,686,708	3,388,410	2,916,445	3,019,538	3,790,251	3,841,372	3,511,568	2,864,467	3,249,213	3,644,057	41,905,895
46		Commercial - Small	RCL	377,163	378,983	384,309	353,019	298,149	305,349	340,871	336,117	320,425	282,162	304,967	324,934	4,006,448
47		Commercial - Small	TCL	2,369,066	2,345,502	2,355,601	2,138,392	1,904,408	2,108,545	2,289,345	2,328,700	2,272,994	2,005,883	2,134,710	2,076,248	26,329,394
48		Commercial - Large		2,029,329	1,984,942	1,864,451	2,066,009	2,050,885	2,339,790	2,215,131	2,153,540	1,928,775	1,911,524	2,034,009	2,031,795	24,610,180
49		ML - Public Street Lights		5,519	5,389	5,389	5,389	5,389	5,389	5,389	5,389	5,389	5,389	5,389	5,389	64,798
50		Sales for Resale		8,415	8,654	7,983	8,201	7,694	8,191	8,790	8,426	7,922	7,068	9,268	11,960	102,572
51																-
52																-
53		**Total KWH**		8,839,717	8,667,111	8,304,441	7,959,420	7,182,970	7,786,802	8,649,777	8,673,544	8,047,073	7,076,493	7,737,556	8,094,383	97,019,287
54																
55		Source: Bill-Totals-Tabs		1st Qtr Total KWh			2nd Qtr Total KWh			3rd Qtr Total KWh			4th Qtr Total KWh			
56						25,811,269			22,929,192			25,370,394			22,908,432	
57																
58	1			670,418	653,965	615,430	571,338	501,520	485,473	593,215	600,399	554,326	464,054	516,769	607,155	6,834,061
59	2			5,910	6,266	6,040	5,174	3,859	2,821	2,995	2,972	2,944	2,596	3,722	4,933	50,232
60	3			74,072	74,297	75,157	70,015	61,138	59,133	64,688	63,903	61,472	55,562	59,141	65,546	784,122
61	3H			166	298	382	296	89	103	137	136	133	125	110	91	2,066
62	4			280,179	279,927	275,582	253,388	233,827	242,669	264,876	271,641	265,404	242,678	252,282	262,676	3,125,128
63	4H			116	128	128	122	109	117	158	193	146	123	87	109	1,536
64	5			139,382	140,248	129,024	136,548	139,637	159,609	180,468	168,070	148,545	149,199	139,104	141,898	1,771,732
65	6			1,635	1,617	1,617	1,617	1,617	1,558	1,558	1,558	1,558	1,558	1,558	1,612	19,065
66	8			1,511	1,553	1,433	1,472	1,381	1,381	1,482	1,421	1,336	1,192	1,563	2,137	17,863
67				1,173,389	1,158,300	1,104,792	1,039,970	943,176	952,865	1,109,579	1,110,294	1,035,863	917,086	974,336	1,086,155	12,605,806
68																
69	1		D	300,637	294,239	279,239	262,087	234,932	241,437	286,614	289,632	270,362	232,496	254,617	277,252	3,223,543
70	1		S	(68)	(67)	(63)	(59)	(51)	(49)	(60)	(61)	(56)	(47)	(53)	(62)	(697)
71	1		G	369,849	359,792	336,253	309,310	266,639	244,086	306,661	310,828	284,021	231,605	262,205	329,965	3,611,216
72				670,418	653,965	615,430	571,338	501,520	485,473	593,215	600,399	554,326	464,054	516,769	607,155	6,834,061
73																
74	5		D	61,621	62,942	62,955	63,909	65,983	70,465	71,574	71,591	70,247	67,903	63,127	61,679	793,994
75	5		S	(13)	(14)	(13)	(14)	(14)	(16)	(18)	(17)	(15)	(15)	(14)	(14)	(175)
76	5		G	77,775	77,320	66,081	72,653	73,668	89,160	108,912	96,495	78,313	81,311	75,991	80,233	977,913
77				139,382	140,248	129,024	136,548	139,637	159,609	180,468	168,070	148,545	149,199	139,104	141,898	1,771,732
78																

Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026 (R)
Sales Recap
Period Ending December 31, 2024

Line	SC	Customer Class	Type	January	February	March	April	May	June	July	August	September	October	November	December	Totals
79		Residential	D	300,637	294,239	279,239	262,087	234,932	241,437	286,614	289,632	270,362	232,496	254,617	277,252	3,223,543
80		RSAE	D	2,371	2,498	2,417	2,108	1,632	1,330	1,397	1,384	1,370	1,236	1,671	2,016	21,430
81		NRS	D	40,591	40,672	41,060	38,716	34,724	35,285	37,933	37,534	36,412	33,490	35,221	36,750	448,390
82		NRH	D	92	156	196	154	49	59	76	76	74	70	62	50	1,112
83		CS	D	120,732	121,897	119,458	113,857	109,999	117,659	124,818	126,185	122,958	115,185	116,954	115,003	1,424,706
84		CSH	D	75	80	80	78	72	78	96	112	91	80	64	72	979
85		IS	D	61,621	62,942	62,955	63,909	65,983	70,465	71,574	71,591	70,247	67,903	63,127	61,679	793,994
86		ML	D	1,127	1,121	1,121	1,121	1,121	1,121	1,121	1,121	1,121	1,121	1,121	1,121	13,458
87		EU	D	735	756	697	716	672	715	768	736	692	617	809	1,044	8,957
88				527,981	524,361	507,223	482,745	449,184	468,149	524,398	528,370	503,327	452,197	473,647	494,987	5,936,569
89																
90		Residential	G	369,849	359,792	336,253	309,310	266,639	244,086	306,661	310,828	284,021	231,605	262,205	329,965	3,611,216
91		RSAE	G	3,540	3,769	3,623	3,067	2,227	1,491	1,598	1,589	1,574	1,361	2,051	2,918	28,807
92		NRS	G	33,488	33,632	34,103	31,305	26,419	23,853	26,761	26,375	25,065	22,077	23,925	28,801	335,804
93		NRH	G	74	143	186	141	40	45	61	61	59	55	48	41	954
94		CS	G	159,476	158,058	156,153	139,557	123,851	125,035	140,085	145,484	142,473	127,518	135,353	147,699	1,700,741
95		CSH	G	41	48	48	44	37	39	62	81	55	42	23	37	557
96		IS	G	77,775	77,320	66,081	72,653	73,668	89,160	108,912	96,495	78,313	81,311	75,991	80,233	977,913
97		ML	G	508	496	496	496	496	437	437	437	437	437	437	491	5,609
98		EU	G	776	798	736	756	709	666	715	685	644	575	754	1,093	8,907
99				645,526	634,056	597,681	557,330	494,086	484,812	585,293	582,035	532,641	464,981	500,788	591,278	6,670,507
100																
101		Residential	S	(68)	(67)	(63)	(59)	(51)	(49)	(60)	(61)	(56)	(47)	(53)	(62)	(697)
102		RSAE	S	(1)	(1)	(1)	(1)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(1)	(5)
103		NRS	S	(7)	(7)	(7)	(6)	(5)	(5)	(6)	(6)	(5)	(5)	(5)	(6)	(72)
104		NRH	S	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
105		CS	S	(29)	(29)	(28)	(26)	(24)	(25)	(27)	(28)	(27)	(25)	(26)	(27)	(319)
106		CSH	S	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
107		IS	S	(13)	(14)	(13)	(14)	(14)	(16)	(18)	(17)	(15)	(15)	(14)	(14)	(175)
108		ML	S	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(2)
109		EU	S													
110				(118)	(117)	(112)	(105)	(95)	(96)	(111)	(112)	(104)	(92)	(99)	(110)	(1,270)

Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026 (R)
Total Operating Revenues
January 1, 2024 to December 31, 2024

Line	Month	MWh Sales	Net Revenue	STAS	Unbilled Revenue	Allocation E Factor	Sub Total Revenues	#450 Forfeited Discounts	#454 Rent from Electric Property	#456 Other Electric Revenues	#495 GSSR over/under Recovery	#495.10 Over/under Collection Unbilled	Total Revenues
1	January	8,839.717	$ 1,173,507	$ (118)	$ -	$ 15,970	$ 1,189,359	$ 2,481	$ 22,181	$ 298	$ (29,097)	$ -	$ 1,185,223
2	February	8,667.111	$ 1,158,417	$ (117)	$ -	$ 15,683	$ 1,173,983	$ 3,353	$ 19,279	$ 1,733	$ (102,278)	$ -	$ 1,096,071
3	March	8,304.441	$ 1,104,904	$ (112)	$ -	$ 14,947	$ 1,119,739	$ 3,073	$ 19,279	$ 517	$ (83,267)	$ -	$ 1,059,341
4	April	7,959.420	$ 1,040,075	$ (105)	$ -	$ 13,712	$ 1,053,682	$ 2,403	$ 20,179	$ 457	$ (47,009)	$ -	$ 1,029,714
5	May	7,182.970	$ 943,271	$ (95)	$ -	$ 11,730	$ 954,906	$ 2,254	$ 18,379	$ 986	$ 76,892	$ -	$ 1,053,417
6	June	7,786.802	$ 952,961	$ (96)	$ -	$ 13,666	$ 966,531	$ 1,849	$ 19,279	$ 3,558	$ 46,914	$ -	$ 1,038,132
7	July	8,649.777	$ 1,109,690	$ (111)	$ -	$ 16,387	$ 1,125,966	$ 2,623	$ 19,279	$ 1,884	$ 24,092	$ -	$ 1,173,843
8	August	8,673.544	$ 1,110,405	$ (112)	$ -	$ 16,680	$ 1,126,974	$ 2,247	$ 20,629	$ 603	$ (28,160)	$ -	$ 1,122,293
9	September	8,047.073	$ 1,035,968	$ (104)	$ -	$ 15,378	$ 1,051,241	$ 1,757	$ 19,279	$ 1,697	$ (12,393)	$ -	$ 1,061,581
10	October	7,076.493	$ 917,178	$ (92)	$ -	$ 13,201	$ 930,287	$ 2,849	$ 19,279	$ 698	$ 50,228	$ -	$ 1,003,342
11	November	7,737.566	$ 974,434	$ (99)	$ -	$ 14,621	$ 988,957	$ 1,983	$ 19,879	$ 5,349	$ 37,136	$ -	$ 1,053,305
12	December	8,094.383	$ 1,086,265	$ (110)	$ 183,735	$ (13,787)	$ 1,256,103	$ 1,987	$ 49,811	$ 5,119	$ 58,629	$ (89,521)	$ 1,282,129
13	Totals	97,019.297	$ 12,607,075	$ (1,270)	$ 183,735	$ 148,188	$ 12,937,729	$ 28,860	$ 266,738	$ 22,899	$ (8,313)	$ (89,521)	$ 13,158,391

Account		
440.0	Residential	7,041,516
440.3	Residential STAS	(702)
442.0	Commercial	4,014,195
442.01	Industrial	1,846,014
442.3	Commercial STAS	(391)
442.31	Industrial STAS	(175)
444.0	Public Street & Highway	19,204
444.3	Public Street & Highway STAS	(2)
447.0	Sales for Resale	18,070
450.0	Forfieted Discounts	28,860
454.0	Rent from Electric Property	266,738
456.0	Other Electric Revenue	22,796
456.1	Other Electric Revenue-STAS	-
456.2	Investment Charge EU	103
495.0	GSSR Over/Under Collections	(8,313)
495.1	Over/Under Collection Unbilled	(89,521)
		13,158,391

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WP_C1 (R)

Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026 (R)
Expenses By Account and By Type
Year 2023, HY 2024, FTY 2025 and FPFTY 2026

				Annuals Totals, Detailed by Type			
Line	Account	#	Type	2023	2024	2025	2026
1	PPower-Power Purchases			8,108,800	6,587,193	7,834,837	9,111,330
2	Total Power Purchased			8,108,800	6,587,193	7,834,837	9,111,330
3							
4	580.01-Oper.Superv. Eng-Labor	580	Labor	-	4,043		-
5	580.02-Oper.Superv. Eng-OH	580	OH	-	4,078		-
6	580.03-Oper.Superv. Eng-Transp	580	Trans/Mat				-
7	582.01-Station Exp-Labor	582	Labor				-
8	582.02-Station Exp-OH	582	Trans/Mat	-	-		-
9	583.01-OH Line Exp-Labor	583	Labor	(2,379)	(1,766)	3,980	4,098
10	583.02-OH Line Exp-OH	583	OH	3,064	2,535	1,814	1,922
11	583.05-OH Line Exp-Misc	583	Trans/Mat				-
12	585.01-Street/Signal Light-Labor	585	Labor	-	127	178	182
13	585.02-Street/Signal Light-OH	585	OH	675	19	81	85
14	585.04-Street/Signal Light-Matl	585	Trans/Mat				-
15	586.01-Meter Exp-Labor	586	Labor	19,146	21,287	26,220	26,981
16	586.02-Meter Exp-OH	586	OH	14,498	15,697	11,725	12,422
17	586.03-Meter Exp-Transp	586	Trans/Mat				-
18	586.05-Meter Exp-Misc	586	Other	-	-	500	500
19	587.01-Cust Install Exp-Labor	587	Labor	-	109	178	182
20	587.02-Cust Install Exp-OH	587	OH	-	98	81	85
21	587.04-Cust Install Exp-Matl	587	Trans/Mat				-
22	588.00 Misc Distr Exps	588	Other	1,084	(1,389)	6,800	6,800
23	588.01 Labor - Misc Distr Expens	588	Labor	37,840	29,489	61,875	64,014
24	588.02 OH - Misc Distr Exp	588	OH	48,793	40,264	62,211	62,486
25	588.03-Misc Distr Exp-Transp	588	Trans/Mat				-
26	588.11 Labor - Genl Type Mtg - C	588	Labor	7,872	11,084	8,467	8,766
27	588.12 OH - Genl Type Mtg	588	OH	5,099	8,757	9,349	9,351
28	588.13-Misc Dist Exp-Genl Mtg T	588	Trans/Mat				-
29	588.20-Misc Dist Exp-Outside Tra	588	Other	7,534	9,606	15,000	15,000
30	588.21-Misc Dist Exp-Outside Tra	588	Labor	5,846	10,141	11,506	11,846
31	588.22-Misc Dist Exp-Outside Tra	588	OH	1,559	2,482	5,245	5,556
32	588.23-Misc Dist Exp-Outside Tra	588	Trans/Mat	-	699		-
33	588.31 Labor - On Call - Standby	588	Labor	12,639	12,129	14,799	14,651
34	588.32-Misc Dist Exp-On Call Sta	588	OH	3,575	3,097	6,746	6,873
35	588.40 Safety Mtgs & Training	588	Other	4,268	6,339		-
36	588.41 Labor - Safety Mtgs & Tra	588	Labor	22,120	28,265	39,910	41,188
37	588.42 OH - Safety Mtgs & Tra	588	OH	12,442	12,981	38,515	39,156
38	588.90 Misc Dist-Staking Dept-Tc	588	Other				-
39	589.00-Distr rents	589	Other	30,717	32,950	35,300	35,300
40						-	-
41	**Total operations**			236,392	253,121	360,478	367,446

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Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026 (R)
Expenses By Account and By Type
Year 2023, HY 2024, FTY 2025 and FPFTY 2026

				Annuals Totals, Detailed by Type			
Line	Account	#	Type	2023	2024	2025	2026
42							-
43	590.01-Maint, Supv & Eng-Labor	590	Labor	37,403	41,204	41,076	42,663
44	590.02-Maint, Supv & Eng-OH	590	OH	48,308	56,671	59,695	59,121
45	590.03-Maint, Supv & Eng-Transp	590	Trans/Mat				-
46	591.01-Maint of Structures-Labor	591	Labor	792	-		-
47	591.02-Maint of Structures-OH	591	Trans/Mat	1,056	-		-
48	592.01-Maint of Station Equip-Lal	592	Labor	678	1,255	1,869	1,924
49	592.02-Maint of Station Equip-OH	592	OH	1,863	1,621	2,702	126,752
50	592.03-Maint of Station Equip-Tra	592	Trans/Mat				-
51	592.04- Matl/Supp Inv-Maint Sta	592	Other				(110,119)
52	592.11- Substation Inspect In-hou	592	Labor	3,156	334		-
53	592.00-Substation Insp-In House-	592	Other				-
54	593.00 Maint OH Lines	593	Other				-
55	593.01 Labor - OH Line Maintena	593	Labor	140,138	175,692	202,337	208,333
56	593.02 OH - OH Line Mainten	593	OH	126,049	129,933	101,742	107,224
57	593.03-Maint of OH Lines-Transp	593	Trans/Mat				-
58	593.04 Matl/Supp Inv-Maint Ove	593	Trans/Mat	767	-		-
59	593.10 Maint OH Lines - Brush C	593	Other	407,770	444,468	480,457	480,457
60	593.11 OH Line-Tree Trim-In-H	593	Labor	17,691	15,547	16,743	17,240
61	593.12-Tree Trim-In House-Trans	593	Trans/Mat			7,633	8,087
62	593.13-Tree Trimming-In House-(	593	Labor				-
63	593.21-Overhead Line Inspection	593	Trans/Mat	38,954	6,362	24,679	25,411
64	593.22-OH Line Insp-Line Crew-C	593	OH	8,264	1,470	11,251	11,920
65	593.30 Maint Of OH-Working Off	593	Other				-
66	593.31 Labor - Maint Lines - Wor	593	Labor	355	-		-
67	593.32 OH - Maint Lines - Work (	593	OH	(355)	-		-
68	593.40 Maint Of OH Lines - Meal	593	Other	919	359	1,500	1,500
69	593.50-Maint O/H Line-Major Sto	593	Other	27,765	31,980		-
70	593.51 Labor - Maint Lines - Majo	593	Labor	30,707	26,331	53,377	54,367
71	593.52 OH Lines- Major	593	Other	6,092	4,524	15,216	16,120
72	593.60 Maint Lines-Major Storm-I	593	Labor				-
73	593.80 Maint O/H - Testing-Tools	593	Other	24,438	26,984	40,500	40,500
74	593.90 Maint-Special Equip-Repa	593	Other				-
75	593.91-Special Equip Insp-Labor	593	Labor	7,214	6,137	9,367	9,646
76	593.92-Special Equipment Inspec	593	Trans/Mat			4,270	4,524

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Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026 (R)
Expenses By Account and By Type
Year 2023, HY 2024, FTY 2025 and FPFTY 2026

				Annuals Totals, Detailed by Type			
Line	Account	#	Type	2023	2024	2025	2026
77	594.01-Maint of UG Lines-Labor	594	Labor	1,751	4,369	4,353	4,483
78	594.02-Maint of UG Lines-OH	594	OH	1,588	2,645	1,984	2,102
79	594.03-Maint of UG Lines-Transp	594	Trans/Mat				-
80	594.04-Maint of UG Lines-Matl	594	Trans/Mat				-
81	594.05-Maint UG Lines- Misc	594	Other			-	-
82	594.11- UG Inspect In-hours	594	Labor	1,847	113	150	156
83	594.12- UG Inspect OH	594	OH			69	73
84	594.90- Maint UG Lines PA ON	594	Other	23,250	23,079	33,500	33,500
85	595.01-Maint of Line Xfrnrs-Labor	595	Labor	1,742	3,059	3,347	3,447
86	595.02-Maint of Line Xfrnrs-OH	595	OH	949	1,358	1,526	1,617
87	595.03-Maint of Line Xfrnrs-Trans	595	Trans/Mat				-
88	595.05-Maint Line Xfrnrs-Misc	595	Other				-
89	595.80-Maint of Line Xfrnrs-Disp	595	Trans/Mat	2,987	10,115	3,000	3,000
90	596.01-Maint of Street Lights-Lab	596	Labor	1,700	962	623	641
91	596.02-Maint of Street Lights-OH	596	OH	1,291	650	284	301
92	596.04-Maint of Street Lights-Mat	596	Trans/Mat				-
93	597.00-Maint of Meters	597	Labor	30,912	25,037		-
94	597.01-Maint of Meters-Labor	597	Labor	32,568	31,514	34,412	35,432
95	597.02-Maint of Meters-OH	597	OH	9,842	7,010	15,688	16,620
96	597.03-Maint of Meters-Transp	597	Trans/Mat				-
97	597.04-Maint of Meters-Matl	597	Trans/Mat	(529)	8		-
98	597.05-Maint of Meters-Misc	597	Trans/Mat				-
99	597.41-Maintenance of Meters-T\	597	Labor			623	641
100	597.42-Maintenance of Meters-T\	597	OH			27,484	27,501
101	597.44-Maint TWACS Meters	597	Other	2,674	937	-	-
102							-
103	**Total Maint**			1,042,595	1,081,729	1,201,459	1,235,182
104							
105	**Total Distr Exp**			1,278,988	1,334,849	1,561,937	1,602,629
106				-	-		

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Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026 (R)
Expenses By Account and By Type
Year 2023, HY 2024, FTY 2025 and FPFTY 2026

				Annuals Totals, Detailed by Type			
Line	Account	#	Type	2023	2024	2025	2026
107	**CustS ACCOUNTING & COLLECTING Exp**						-
108	902.01-Meter Reading Exp-Labor	902	Labor	10,767	12,359	10,936	11,261
109	902.02-Meter Reading Exp-OH	902	OH	9,042	9,416	4,986	5,283
110	902.03-Meter Reading Exp-Trans	902	Trans/Mat				-
111	903.00-Cust Rec & Coll Exp	903	Other	5,411	6,868	5,000	5,000
112	903.01-Cust Rec & Collect Exp-L	903	Labor	201,641	203,082	215,355	230,436
113	903.02-Cust Rec & Collect Exp-O	903	OH	260,964	276,153	310,965	317,430
114	903.03-Cust Rec & Collect Exp-T	903	Trans/Mat				-
115	903.20-Cust Rec Exp-Seminars-M	903	Other			500	500
116	903.30-Cust Rec Exp-Postage	903	Other	40,256	43,390	43,375	43,375
117	903.40-Cust Coll-Credit Check	903	Other	858	801	900	900
118	903.45-Cust Coll-EGS Monthly S	903	Other	3,260	4,252	3,600	3,600
119	903.50-Cust Rec Exp-Billing Sup	903	Other	496	1,153	3,200	3,200
120	903.60-Cust Rec Exp-NISC Com	903	Other	128,903	135,388	163,600	163,600
121	903.81-Cust Rec Exp-Collect-Lab	903	Labor	69,880	70,302	75,899	81,136
122	903.82-Cust Rec Exp-Collecting-(	903	OH	88,320	92,349	107,690	109,963
123	903.83-Cust Rec Exp-Collect-Tra	903	Trans/Mat				-
124	903.90-Cust Rec Exp-Delinq	903	Other			500	500
125	903.91-Cust Rec Exp-Delinq-Lab	903	Labor	36,011	36,526	39,266	41,544
126	903.92-Cust Rec Exp-Delinq-OH	903	OH	36,950	37,371	45,181	46,326
127	903.05-Cust Rec Exp-Delinq-Mis	903	Other				-
128	904.00-Uncollectable Accounts	904	Other	-	-	20,000	20,000
129						-	-
130	**Total Cust accounting & collecting**			892,757	929,410	1,050,953	1,084,054
131						**0**	
132	**SALES PROMOTION Exp**						-
133	908.00-Cust Assist-Exp	908	Other	295	-	1,000	1,000
134	908.51-Cust Assist-Energy Audit-	908	Labor	1,735	180	156	161
135	908.52-Cust Assist-Energy Audit-	908	OH			71	76
136	908.05-Cust Assist-Energy Audit-	908	Other				-
137	909.00-Cust Service Info-Misc	909	Other	314	800	16,000	6,000
138	913.00-Advertising Exp	913	Other	1,738	2,191	2,500	2,500
139						-	-
140	**Total Sales Promotion Exp**			4,082	3,171	19,727	9,737
141							-

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Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026 (R)
Expenses By Account and By Type
Year 2023, HY 2024, FTY 2025 and FPFTY 2026

				Annuals Totals, Detailed by Type			
Line	Account	#	Type	2023	2024	2025	2026
142	**ADMINISTRATIVE & Genl Exp**						-
143	920.00-A&G Salaries	920	Labor	22,250	11,954	9,000	9,000
144	920.01-A&G Salaries-Labor	920	Labor	258,765	292,156	325,262	352,797
145	920.02-A&G Salaries-OH	920	OH	351,031	402,852	468,335	484,732
146	920.03-A&G Salaries-Transp	920	Trans/Mat				-
147	920.40-A&G-President-CEO	920	Labor	5,377	6,176	12,000	12,000
148	920.50-A&G-V-P Fin Adminis	920	Labor	8,392	26,510	17,600	15,000
149	920.60-A&G-V-P Eng Oper	920	Labor	2,059	3,188	15,000	15,000
150	920.70-A&G- Staff	920	Labor	4,766	15,065	22,700	22,700
151	921.00-Off Supp & Exp	921	Other	9,054	12,730	11,540	11,540
152	921.10-Off Supp & Exp-Utilities	921	Other	4,803	5,835	6,060	6,060
153	921.40-Off Exp-Subs/Membershi	921	Other	4,042	5,186	3,400	3,400
154	921.50-Off Exp-Off Supp	921	Other	6,413	8,823	23,260	23,260
155	921.60-Off Exp-WECO Telephon	921	Other	31,375	47,437	49,500	49,500
156	921.70-Off Exp-Dispatch Telepho	921	Other	79,441	89,963	90,800	90,800
157	921.90-Off Exp-Misc	921	Other	9,938	8,780	20,060	20,060
158	921.99-Off Exp-Working Capital (	921	Other	(83,141)	(65,853)	(81,613)	(94,910)
159	923.00-Outside Svc Empl	923	Other	26,301	24,421	29,325	29,325
160	923.10-Outside Svc Empl-Auditor	923	Other	31,951	34,886	34,000	34,000
161	923.20-Outside Svc Empl-Engine	923	Other	75	610	5,000	5,000
162	923.30-Outside Svc Empl-Attorne	923	Other	21,703	16,158	25,000	25,000
163	923.90-Outside Services Employ	923	Other	7,859	61,040	61,200	61,200
164	924.00-Property Insurance	924	Other	51,268	53,098	61,410	61,410
165	925.00-Injuries & Damages	925	Other				-
166	926.11-Employee Pen Ben-Healt	926	OH	-	-		-
167	926.20-Empl Pen Ben-Postret He	926	OH				-
168	926.70-Employee Pen Ben-Life Ir	926	OH				-
169	926.99-Employee Pen Ben-SERF	926	OH				-
170	928.00-Regulatory Commission E	928	Other	32,144	42,985	43,000	43,000
171	928.01-Rate Case Exp	928	Other	36,222	-		110,393
172	930.00-Directors Exp	930	Other	101,167	83,257	95,851	106,681
173	930.11-Misc Gen Exp-GPS Map I	930	Other	-	-		-
174	930.20-Misc Gen Exp-GPS Map-I	930	Labor	3,074	-	3,100	3,100
175	930.21-Misc Gen Exp-GPS Map-(	930	Other				-
176	930.22-Misc Gen Exp-GPS Mapp	930	OH				-
177	930.24-Misc Gen Exp-GPS Mapp	930	Other				-
178	930.25-Misc Gen Exp-Covid Expe	930	Other	-	-		-
179	930.30-Misc Gen Exp- Misc	930	Other	1,113	1,147	800	800

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Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026 (R)
Expenses By Account and By Type
Year 2023, HY 2024, FTY 2025 and FPFTY 2026

Line	Account	#	Type	Annuals Totals, Detailed by Type 2023	2024	2025	2026
180	931.00-Rents	931	Other	2,442	3,611	2,200	2,200
181	932.00-Maint of Genl Property	932	Other	48,827	40,021	52,163	46,736
182	932.01-Maint of Genl Property-La	932	Labor	46,719	9,859	10,814	11,135
183	932.02-Maint of Genl Property-Ol	932	OH			4,930	5,223
184	932.10-Maint of Genl Property-Of	932	Other	11,518	6,205	11,000	11,000
185	932.11-Maint Genl Prop-Off Bldg-	932	Labor	3,217	-		-
186	932.12-Maint Genl Prop-Off Bldg-	932	OH				-
187	932.20-Maint Genl-Communicatic	932	Other	-	-	500	500
188	932.21-Maint Genl-Comm Equip-I	932	Labor				-
189	932.22-Maint Genl-Comm Equip-I	932	OH				-
190	932.30-Maint Gen Property-Plant	932	Other	422	12,688	12,550	12,550
191	932.31-Maint Gen Prop-Plant Bld	932	Labor	630	1,505	1,564	1,611
192	932.32-Maint Gen Prop-Plant Bld	932	OH			713	756
193	932.41-Maint Gen Prop-Apt Hous	932	Labor				-
194	932.42-Maint Gen Prop-Apt Hous	932	OH				-
195	932.70-Maint Gen Office Equip	932	Other	1,248	1,908	3,800	3,800
196	932.05-Maint Genl Property- Misc	932	Other	-	-	-	-
197						1,451,824	1,596,359
198	**Total Administrative & Genl Exp**			1,142,464	1,264,200	1,451,824	1,596,359
199	Detail, adjusted for WC Claim						0
200	**Total Operating Exp**			3,318,291	3,531,630	4,084,441	4,292,779
201	From OM			*3,318,291*	*3,531,630*	*4,119,254*	*4,332,745*
202	Adjustments				*='C:\Users\hgorm\D ='C:\Users\hgorm\Documents Laptop\CTE-2*		
203	Working Capital claim			83,141	65,853	81,613	94,910
204	Rate case Exp			-	-		
205				3,401,431	3,597,484	4,166,054	4,387,688
206	From OM						
207	From C1-1			-	1,318,721		
208	Differrence			3,401,431	2,278,763		
209							
210							
211	Labor		Labor	1,087,018	1,135,323	1,294,042	1,357,763
212	OH		OH	1,033,810	1,109,508	1,301,063	1,460,956
213	Trans/Mat		Trans/Ma	43,235	17,184	39,582	41,022
214	Other		Other	1,154,228	1,269,615	1,449,754	1,433,038
215	WC		WC	-	-	-	-
216				3,318,291	3,531,630	4,084,441	4,292,779

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Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026 (R)
Expenses By Account and By Type
Year 2023, HY 2024, FTY 2025 and FPFTY 2026

Line	Account	#	Type	E&O 2025	Office 2025	Admin & Misc 2025	C&T Payroll 2025	Union Payroll 2025	Transportation 2025
1	PPower-Power Purchases								
2	Total Power Purchased								
3									
4	580.01-Oper.Superv. Eng-Labor	580	Labor						
5	580.02-Oper.Superv. Eng-OH	580	OH						
6	580.03-Oper.Superv. Eng-Transp	580	Trans/Mat						
7	582.01-Station Exp-Labor	582	Labor						
8	582.02-Station Exp-OH	582	Trans/Mat						
9	583.01-OH Line Exp-Labor	583	Labor					2,937	1,043
10	583.02-OH Line Exp-OH	583	OH					1,814	
11	583.05-OH Line Exp-Misc	583	Trans/Mat						
12	585.01-Street/Signal Light-Labor	585	Labor					131	47
13	585.02-Street/Signal Light-OH	585	OH					81	
14	585.04-Street/Signal Light-Matl	585	Trans/Mat						
15	586.01-Meter Exp-Labor	586	Labor	500			-	18,979	6,741
16	586.02-Meter Exp-OH	586	OH				-	11,725	
17	586.03-Meter Exp-Transp	586	Trans/Mat						
18	586.05-Meter Exp-Misc	586	Other	500					
19	587.01-Cust Install Exp-Labor	587	Labor				-	131	47
20	587.02-Cust Install Exp-OH	587	OH				-	81	
21	587.04-Cust Install Exp-Matl	587	Trans/Mat						
22	588.00 Misc Distr Exps	588	Other	6,800					
23	588.01 Labor - Misc Distr Expens	588	Labor				34,092	20,501	7,282
24	588.02 OH - Misc Distr Exp	588	OH				49,545	12,666	
25	588.03-Misc Distr Exp-Transp	588	Trans/Mat						
26	588.11 Labor - Genl Type Mtg - C	588	Labor				5,503	2,187	777
27	588.12 OH - Genl Type Mtg	588	OH				7,997	1,352	
28	588.13-Misc Dist Exp-Genl Mtg T	588	Trans/Mat						
29	588.20-Misc Dist Exp-Outside Tra	588	Other	15,000					
30	588.21-Misc Dist Exp-Outside Tra	588	Labor				-	8,490	3,016
31	588.22-Misc Dist Exp-Outside Tra	588	OH				-	5,245	
32	588.23-Misc Dist Exp-Outside Tra	588	Trans/Mat						
33	588.31 Labor - On Call - Standby	588	Labor					10,920	3,879
34	588.32-Misc Dist Exp-On Call Sta	588	OH					6,746	
35	588.40 Safety Mtgs & Training	588	Other						
36	588.41 Labor - Safety Mtgs & Tra	588	Labor				10,698	21,556	7,656
37	588.42 OH - Safety Mtgs & Tra	588	OH	9,650			15,547	13,318	
38	588.90 Misc Dist-Staking Dept-Tc	588	Other						
39	589.00-Distr rents	589	Other	35,300					
40									
41	**Total operations**			67,750	-	-	123,381	138,860	30,487

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Rate Case with Fully Projected Future Test Year 2026 (R)
Expenses By Account and By Type
Year 2023, HY 2024, FTY 2025 and FPFTY 2026

Line	Account	#	Type	E&O 2025	Office 2025	Admin & Misc 2025	C&T Payroll 2025	Union Payroll 2025	Transportation 2025
42									
43	590.01-Maint, Supv & Eng-Labor	590	Labor				41,076		
44	590.02-Maint, Supv & Eng-OH	590	OH				59,695		
45	590.03-Maint, Supv & Eng-Transp	590	Trans/Mat						
46	591.01-Maint of Structures-Labor	591	Labor						
47	591.02-Maint of Structures-OH	591	Trans/Mat						
48	592.01-Maint of Station Equip-Lal	592	Labor					1,379	490
49	592.02-Maint of Station Equip-OH	592	OH	1,850				852	
50	592.03-Maint of Station Equip-Tra	592	Trans/Mat						
51	592.04- Matl/Supp Inv-Maint Sta	592	Other						
52	592.11- Substation Inspect In-hou	592	Labor						
53	592.00-Substation Insp-In House-	592	Other						
54	593.00 Maint OH Lines	593	Other						
55	593.01 Labor - OH Line Maintena	593	Labor					149,305	53,032
56	593.02 OH - OH Line Mainten	593	OH	9,500				92,242	
57	593.03-Maint of OH Lines-Transp	593	Trans/Mat						
58	593.04 Matl/Supp Inv-Maint Ove	593	Trans/Mat						
59	593.10 Maint OH Lines - Brush C	593	Other	480,457					
60	593.11 OH Line-Tree Trim-In-H	593	Labor					12,355	4,388
61	593.12-Tree Trim-In House-Trans	593	Trans/Mat					7,633	
62	593.13-Tree Trimming-In House-(	593	Labor						
63	593.21-Overhead Line Inspection	593	Trans/Mat				-	18,211	6,468
64	593.22-OH Line Insp-Line Crew-C	593	OH				-	11,251	
65	593.30 Maint Of OH-Working Off	593	Other						
66	593.31 Labor - Maint Lines - Worl	593	Labor						
67	593.32 OH - Maint Lines - Work (	593	OH						
68	593.40 Maint Of OH Lines - Meal	593	Other	1,500					
69	593.50-Maint O/H Line-Major Sto	593	Other						
70	593.51 Labor - Maint Lines - Majo	593	Labor	20,000			-	24,629	8,748
71	593.52 OH Lines- Major	593	Other				-	15,216	
72	593.60 Maint Lines-Major Storm-I	593	Labor						
73	593.80 Maint O/H - Testing-Tools	593	Other	40,500					
74	593.90 Maint-Special Equip-Repa	593	Other						
75	593.91-Special Equip Insp-Labor	593	Labor					6,912	2,455
76	593.92-Special Equipment Inspec	593	Trans/Mat					4,270	

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Line	Account	#	Type	E&O 2025	Office 2025	Admin & Misc 2025	C&T Payroll 2025	Union Payroll 2025	Transportation 2025
77	594.01-Maint of UG Lines-Labor	594	Labor				-	3,212	1,141
78	594.02-Maint of UG Lines-OH	594	OH				-	1,984	
79	594.03-Maint of UG Lines-Transp	594	Trans/Mat						
80	594.04-Maint of UG Lines-Matl	594	Trans/Mat						
81	594.05-Maint UG Lines- Misc	594	Other						
82	594.11- UG Inspect In-hours	594	Labor					111	39
83	594.12- UG Inspect OH	594	OH					69	
84	594.90- Maint UG Lines PA ON	594	Other	33,500					
85	595.01-Maint of Line Xfrnrs-Labor	595	Labor					2,470	877
86	595.02-Maint of Line Xfrnrs-OH	595	OH					1,526	
87	595.03-Maint of Line Xfrnrs-Trans	595	Trans/Mat						
88	595.05-Maint Line Xfrnrs-Misc	595	Other						
89	595.80-Maint of Line Xfrnrs-Disp	595	Trans/Mat	3,000					
90	596.01-Maint of Street Lights-Lab	596	Labor					460	163
91	596.02-Maint of Street Lights-OH	596	OH					284	
92	596.04-Maint of Street Lights-Mat	596	Trans/Mat						
93	597.00-Maint of Meters	597	Labor						
94	597.01-Maint of Meters-Labor	597	Labor					25,393	9,019
95	597.02-Maint of Meters-OH	597	OH					15,688	
96	597.03-Maint of Meters-Transp	597	Trans/Mat						
97	597.04-Maint of Meters-Matl	597	Trans/Mat						
98	597.05-Maint of Meters-Misc	597	Trans/Mat						
99	597.41-Maintenance of Meters-TV	597	Labor					460	163
100	597.42-Maintenance of Meters-TV	597	OH	27,200				284	
101	597.44-Maint TWACS Meters	597	Other						
102									
103	**Total Maint**			617,507	-	-	100,771	396,196	86,985
104									
105	**Total Distr Exp**			685,257	-	-	224,153	535,056	117,471
106									

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Rate Case with Fully Projected Future Test Year 2026 (R)
Expenses By Account and By Type
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Line	Account	#	Type	E&O 2025	Office 2025	Admin & Misc 2025	C&T Payroll 2025	Union Payroll 2025	Transportation 2025
107	**CustS ACCOUNTING & COLLECTING Exp**								
108	902.01-Meter Reading Exp-Labor	902	Labor					8,070	2,866
109	902.02-Meter Reading Exp-OH	902	OH					4,986	
110	902.03-Meter Reading Exp-Trans	902	Trans/Mat						
111	903.00-Cust Rec & Coll Exp	903	Other			5,000			
112	903.01-Cust Rec & Collect Exp-L	903	Labor				213,345	1,483	527
113	903.02-Cust Rec & Collect Exp-O	903	OH				310,049	916	
114	903.03-Cust Rec & Collect Exp-T	903	Trans/Mat						
115	903.20-Cust Rec Exp-Seminars-M	903	Other		500				
116	903.30-Cust Rec Exp-Postage	903	Other		43,375				
117	903.40-Cust Coll-Credit Check	903	Other		900				
118	903.45-Cust Coll-EGS Monthly S	903	Other		3,600				
119	903.50-Cust Rec Exp-Billing Sup	903	Other		3,200				
120	903.60-Cust Rec Exp-NISC Com	903	Other	8,500	155,100				
121	903.81-Cust Rec Exp-Collect-Lab	903	Labor				73,281	1,932	686
122	903.82-Cust Rec Exp-Collecting-(	903	OH				106,497	1,193	
123	903.83-Cust Rec Exp-Collect-Tra	903	Trans/Mat						
124	903.90-Cust Rec Exp-Delinq	903	Other		500				
125	903.91-Cust Rec Exp-Delinq-Lab	903	Labor				27,351	8,792	3,123
126	903.92-Cust Rec Exp-Delinq-OH	903	OH				39,749	5,432	
127	903.05-Cust Rec Exp-Delinq-Mis	903	Other						
128	904.00-Uncollectable Accounts	904	Other		20,000				
129									
130	**Total Cust accounting & collecting**			8,500	227,175	5,000	770,272	32,804	7,202
131									
132	**SALES PROMOTION Exp**								
133	908.00-Cust Assist-Exp	908	Other		1,000				
134	908.51-Cust Assist-Energy Audit-	908	Labor					115	41
135	908.52-Cust Assist-Energy Audit-	908	OH					71	
136	908.05-Cust Assist-Energy Audit-	908	Other						
137	909.00-Cust Service Info-Misc	909	Other		16,000				
138	913.00-Advertising Exp	913	Other		2,500				
139									
140	**Total Sales Promotion Exp**			-	19,500	-	-	186	41
141									

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Expenses By Account and By Type
Year 2023, HY 2024, FTY 2025 and FPFTY 2026

Line	Account	#	Type	E&O 2025	Office 2025	Admin & Misc 2025	C&T Payroll 2025	Union Payroll 2025	Transportation 2025
142	**ADMINISTRATIVE & Genl Exp**								
143	920.00-A&G Salaries	920	Labor			9,000			
144	920.01-A&G Salaries-Labor	920	Labor				322,262		3,000
145	920.02-A&G Salaries-OH	920	OH				468,335		
146	920.03-A&G Salaries-Transp	920	Trans/Mat						
147	920.40-A&G-President-CEO	920	Labor	12,000					
148	920.50-A&G-V-P Fin Adminis	920	Labor			17,600			
149	920.60-A&G-V-P Eng Oper	920	Labor	15,000					
150	920.70-A&G- Staff	920	Labor		22,700				
151	921.00-Off Supp & Exp	921	Other		5,540	6,000			
152	921.10-Off Supp & Exp-Utilities	921	Other			6,060			
153	921.40-Off Exp-Subs/Membershi	921	Other		3,400				
154	921.50-Off Exp-Off Supp	921	Other		23,260				
155	921.60-Off Exp-WECO Telephon	921	Other	-		49,500			
156	921.70-Off Exp-Dispatch Telepho	921	Other	86,000		4,800			
157	921.90-Off Exp-Misc	921	Other		17,700	2,360			
158	921.99-Off Exp-Working Capital C	921	Other			(81,613)			
159	923.00-Outside Svc Empl	923	Other		3,925	25,400			
160	923.10-Outside Svc Empl-Auditor	923	Other			34,000			
161	923.20-Outside Svc Empl-Engine	923	Other	5,000					
162	923.30-Outside Svc Empl-Attorne	923	Other			25,000			
163	923.90-Outside Services Employe	923	Other			61,200			
164	924.00-Property Insurance	924	Other			61,410			
165	925.00-Injuries & Damages	925	Other						
166	926.11-Employee Pen Ben-Healtl	926	OH						
167	926.20-Empl Pen Ben-Postret He	926	OH						
168	926.70-Employee Pen Ben-Life In	926	OH						
169	926.99-Employee Pen Ben-SERF	926	OH						
170	928.00-Regulatory Commission E	928	Other			43,000			
171	928.01-Rate Case Exp	928	Other						
172	930.00-Directors Exp	930	Other			95,851			
173	930.11-Misc Gen Exp-GPS Map I	930	Other						
174	930.20-Misc Gen Exp-GPS Map-I	930	Labor	3,100					
175	930.21-Misc Gen Exp-GPS Map-(	930	Other						
176	930.22-Misc Gen Exp-GPS Mapp	930	OH						
177	930.24-Misc Gen Exp-GPS Mapp	930	Other						
178	930.25-Misc Gen Exp-Covid Expe	930	Other						
179	930.30-Misc Gen Exp- Misc	930	Other	800					

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Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026 (R)
Expenses By Account and By Type
Year 2023, HY 2024, FTY 2025 and FPFTY 2026

Line	Account	#	Type	E&O 2025	Office 2025	Admin & Misc 2025	C&T Payroll 2025	Union Payroll 2025	Transportation 2025
180	931.00-Rents	931	Other		2,200				
181	932.00-Maint of Genl Property	932	Other	11,500		40,663			
182	932.01-Maint of Genl Property-La	932	Labor					7,980	2,834
183	932.02-Maint of Genl Property-Ol	932	OH					4,930	
184	932.10-Maint of Genl Property-Of	932	Other	11,000					
185	932.11-Maint Genl Prop-Off Bldg-	932	Labor						
186	932.12-Maint Genl Prop-Off Bldg-	932	OH						
187	932.20-Maint Genl-Communicatic	932	Other	500					
188	932.21-Maint Genl-Comm Equip-I	932	Labor						
189	932.22-Maint Genl-Comm Equip-(	932	OH						
190	932.30-Maint Gen Property-Plant	932	Other	12,550			-		
191	932.31-Maint Gen Prop-Plant Bld	932	Labor					1,154	410
192	932.32-Maint Gen Prop-Plant Bld	932	OH					713	
193	932.41-Maint Gen Prop-Apt Hous	932	Labor						
194	932.42-Maint Gen Prop-Apt Hous	932	OH						
195	932.70-Maint Gen Office Equip	932	Other		3,800				
196	932.05-Maint Genl Property- Misc	932	Other						
197				157,450	82,525	400,231	790,597	14,777	6,244
198	**Total Administrative & Genl Exp**			157,450	82,525	400,231	790,597	14,777	6,244
199	Detail, adjusted for WC Claim								
200	**Total Operating Exp**			851,207	329,200	405,231	1,785,022	582,823	130,959
201	From OM								
202	Adjustments			*5\WEL-25\WEL-25 Support\[WEL25 OpBudget2025.xlsx]Assumptions-Breakdown-All'!$I$357*					
203	Working Capital claim								
204	Rate case Exp								
205				851,207	329,200	405,231	1,785,022	582,823	130,959
206	From OM								
207	From C1-1								
208	Differrence								
209									
210									
211	Labor		Labor	50,600	22,700	26,600	727,608	342,044	124,490
212	OH		OH	48,200	-	-	1,057,414	195,449	-
213	Trans/Mat		Trans/Ma	3,000	-	-	-	30,114	6,468
214	Other		Other	749,407	306,500	378,631	-	15,216	-
215	WC		WC	-	-	-	-	-	-
216				851,207	329,200	405,231	1,785,022	582,823	130,959

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Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026 (R)
Expenses By Account and By Type
Year 2023, HY 2024, FTY 2025 and FPFTY 2026

Line	Account	#	Type	E&O 2026	Office 2026	Admin & Misc 2026	C&T Payroll 2026	Union Payroll 2026	Transportation 2026	Annual Totals, By Account 2023	2024	2025	2026
1	PPower-Power Purchases									8,108,800	6,587,193	7,834,837	9,111,330
2	Total Power Purchased									8,108,800	6,587,193	7,834,837	9,111,330
3													
4	580.01-Oper.Superv. Eng-Labor	580	Labor										
5	580.02-Oper.Superv. Eng-OH	580	OH										
6	580.03-Oper.Superv. Eng-Transp	580	Trans/Mat							-	8,121	-	-
7	582.01-Station Exp-Labor	582	Labor										
8	582.02-Station Exp-OH	582	Trans/Mat							-	-	-	-
9	583.01-OH Line Exp-Labor	583	Labor					3,054	1,044				
10	583.02-OH Line Exp-OH	583	OH					1,922					
11	583.05-OH Line Exp-Misc	583	Trans/Mat							686	770	5,794	6,020
12	585.01-Street/Signal Light-Labor	585	Labor					136	46				
13	585.02-Street/Signal Light-OH	585	OH					85					
14	585.04-Street/Signal Light-Matl	585	Trans/Mat							675	146	259	267
15	586.01-Meter Exp-Labor	586	Labor	500			-	19,737	6,744				
16	586.02-Meter Exp-OH	586	OH				-	12,422					
17	586.03-Meter Exp-Transp	586	Trans/Mat										
18	586.05-Meter Exp-Misc	586	Other	500						33,644	36,983	38,445	39,903
19	587.01-Cust Install Exp-Labor	587	Labor				-	136	46				
20	587.02-Cust Install Exp-OH	587	OH				-	85					
21	587.04-Cust Install Exp-Matl	587	Trans/Mat							-	206	259	267
22	588.00 Misc Distr Exps	588	Other	6,800									
23	588.01 Labor - Misc Distr Expens	588	Labor				35,409	21,320	7,285				
24	588.02 OH - Misc Distr Exp	588	OH				49,068	13,418					
25	588.03-Misc Distr Exp-Transp	588	Trans/Mat										
26	588.11 Labor - Genl Type Mtg - C	588	Labor				5,715	2,274	777				
27	588.12 OH - Genl Type Mtg	588	OH				7,920	1,431					
28	588.13-Misc Dist Exp-Genl Mtg T	588	Trans/Mat										
29	588.20-Misc Dist Exp-Outside Tra	588	Other	15,000									
30	588.21-Misc Dist Exp-Outside Tra	588	Labor				-	8,829	3,017				
31	588.22-Misc Dist Exp-Outside Tra	588	OH				-	5,556					
32	588.23-Misc Dist Exp-Outside Tra	588	Trans/Mat										
33	588.31 Labor - On Call - Standby	588	Labor					10,920	3,731				
34	588.32-Misc Dist Exp-On Call Sta	588	OH					6,873					
35	588.40 Safety Mtgs & Training	588	Other										
36	588.41 Labor - Safety Mtgs & Tra	588	Labor				11,111	22,417	7,660				
37	588.42 OH - Safety Mtgs & Tra	588	OH	9,650			15,397	14,109					
38	588.90 Misc Dist-Staking Dept-Tc	588	Other							170,671	173,944	280,422	285,688
39	589.00-Distr rents	589	Other	35,300						30,717	32,950	35,300	35,300
40													
41	**Total operations**			67,750	-	-	124,621	144,724	30,352	236,392	253,121	360,478	367,446

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Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026 (R)
Expenses By Account and By Type
Year 2023, HY 2024, FTY 2025 and FPFTY 2026

Line	Account	#	Type	E&O 2026	Office 2026	Admin & Misc 2026	C&T Payroll 2026	Union Payroll 2026	Transportation 2026	Annual Totals, By Account 2023	2024	2025	2026
42													
43	590.01-Maint, Supv & Eng-Labor	590	Labor				42,663						
44	590.02-Maint, Supv & Eng-OH	590	OH				59,121						
45	590.03-Maint, Supv & Eng-Transp	590	Trans/Mat							85,710	97,875	100,771	101,784
46	591.01-Maint of Structures-Labor	591	Labor										
47	591.02-Maint of Structures-OH	591	Trans/Mat							1,848	-	-	-
48	592.01-Maint of Station Equip-Lal	592	Labor					1,434	490				
49	592.02-Maint of Station Equip-OH	592	OH	125,850				902					
50	592.03-Maint of Station Equip-Tra	592	Trans/Mat										
51	592.04- Matl/Supp Inv-Maint Sta	592	Other	(110,119)									
52	592.11- Substation Inspect In-hou	592	Labor										
53	592.00-Substation Insp-In House-	592	Other							5,697	3,210	4,571	18,557
54	593.00 Maint OH Lines	593	Other										
55	593.01 Labor - OH Line Maintena	593	Labor					155,274	53,059				
56	593.02 OH - OH Line Mainten	593	OH	9,500				97,724					
57	593.03-Maint of OH Lines-Transp	593	Trans/Mat										
58	593.04 Matl/Supp Inv-Maint Ove	593	Trans/Mat										
59	593.10 Maint OH Lines - Brush C	593	Other	480,457									
60	593.11 OH Line-Tree Trim-In-H	593	Labor					12,849	4,391				
61	593.12-Tree Trim-In House-Trans	593	Trans/Mat					8,087					
62	593.13-Tree Trimming-In House-(	593	Labor										
63	593.21-Overhead Line Inspection	593	Trans/Mat				-	18,939	6,472				
64	593.22-OH Line Insp-Line Crew-C	593	OH				-	11,920					
65	593.30 Maint Of OH-Working Off	593	Other										
66	593.31 Labor - Maint Lines - Worl	593	Labor										
67	593.32 OH - Maint Lines - Work (	593	OH										
68	593.40 Maint Of OH Lines - Meal	593	Other	1,500									
69	593.50-Maint O/H Line-Major Sto	593	Other										
70	593.51 Labor - Maint Lines - Majo	593	Labor	20,000			-	25,614	8,753				
71	593.52 OH Lines- Major	593	Other				-	16,120					
72	593.60 Maint Lines-Major Storm-I	593	Labor										
73	593.80 Maint O/H - Testing-Tools	593	Other	40,500									
74	593.90 Maint-Special Equip-Repa	593	Other										
75	593.91-Special Equip Insp-Labor	593	Labor					7,189	2,457				
76	593.92-Special Equipment Inspec	593	Trans/Mat					4,524		836,769	869,788	969,072	985,327

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Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026 (R)
Expenses By Account and By Type
Year 2023, HY 2024, FTY 2025 and FPFTY 2026

Line	Account	#	Type	E&O 2026	Office 2026	Admin & Misc 2026	C&T Payroll 2026	Union Payroll 2026	Transportation 2026	Annual Totals, By Account 2023	2024	2025	2026
77	594.01-Maint of UG Lines-Labor	594	Labor				-	3,341	1,142				
78	594.02-Maint of UG Lines-OH	594	OH				-	2,102					
79	594.03-Maint of UG Lines-Transp	594	Trans/Mat										
80	594.04-Maint of UG Lines-Matl	594	Trans/Mat										
81	594.05-Maint UG Lines- Misc	594	Other										
82	594.11- UG Inspect In-hours	594	Labor					116	40				
83	594.12- UG Inspect OH	594	OH					73					
84	594.90- Maint UG Lines PA ON	594	Other	33,500						28,436	30,206	40,056	40,313
85	595.01-Maint of Line Xfrnrs-Labor	595	Labor					2,569	878				
86	595.02-Maint of Line Xfrnrs-OH	595	OH					1,617					
87	595.03-Maint of Line Xfrnrs-Trans	595	Trans/Mat										
88	595.05-Maint Line Xfrnrs-Misc	595	Other										
89	595.80-Maint of Line Xfrnrs-Disp	595	Trans/Mat	3,000						5,677	14,532	7,873	8,064
90	596.01-Maint of Street Lights-Lab	596	Labor					478	163				
91	596.02-Maint of Street Lights-OH	596	OH					301					
92	596.04-Maint of Street Lights-Mat	596	Trans/Mat							2,991	1,612	907	942
93	597.00-Maint of Meters	597	Labor										
94	597.01-Maint of Meters-Labor	597	Labor					26,408	9,024				
95	597.02-Maint of Meters-OH	597	OH					16,620					
96	597.03-Maint of Meters-Transp	597	Trans/Mat										
97	597.04-Maint of Meters-Matl	597	Trans/Mat										
98	597.05-Maint of Meters-Misc	597	Trans/Mat										
99	597.41-Maintenance of Meters-T\	597	Labor					478	163				
100	597.42-Maintenance of Meters-T\	597	OH	27,200				301					
101	597.44-Maint TWACS Meters	597	Other							75,467	64,505	78,208	80,194
102													
103	**Total Maint**			631,388	-	-	101,784	414,980	87,030	1,042,595	1,081,729	1,201,459	1,235,182
104													
105	**Total Distr Exp**			699,138	-	-	226,405	559,704	117,381	1,278,988	1,334,849	1,561,937	1,602,629
106													

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Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026 (R)
Expenses By Account and By Type
Year 2023, HY 2024, FTY 2025 and FPFTY 2026

Line	Account	#	Type	E&O 2026	Office 2026	Admin & Misc 2026	C&T Payroll 2026	Union Payroll 2026	Transportation 2026	Annual Totals, By Account 2023	2024	2025	2026
107	**CustS ACCOUNTING & COLLECTING Exp**												
108	902.01-Meter Reading Exp-Labor	902	Labor					8,393	2,868				
109	902.02-Meter Reading Exp-OH	902	OH					5,283					
110	902.03-Meter Reading Exp-Trans	902	Trans/Mat							19,808	21,775	15,922	16,544
111	903.00-Cust Rec & Coll Exp	903	Other			5,000							
112	903.01-Cust Rec & Collect Exp-L	903	Labor				228,366	1,543	527				
113	903.02-Cust Rec & Collect Exp-O	903	OH				316,458	972					
114	903.03-Cust Rec & Collect Exp-T	903	Trans/Mat										
115	903.20-Cust Rec Exp-Seminars-M	903	Other		500								
116	903.30-Cust Rec Exp-Postage	903	Other		43,375								
117	903.40-Cust Coll-Credit Check	903	Other		900								
118	903.45-Cust Coll-EGS Monthly S	903	Other		3,600								
119	903.50-Cust Rec Exp-Billing Supp	903	Other		3,200								
120	903.60-Cust Rec Exp-NISC Comp	903	Other	8,500	155,100								
121	903.81-Cust Rec Exp-Collect-Lab	903	Labor				78,440	2,009	686				
122	903.82-Cust Rec Exp-Collecting-(	903	OH				108,698	1,265					
123	903.83-Cust Rec Exp-Collect-Tra	903	Trans/Mat										
124	903.90-Cust Rec Exp-Delinq	903	Other		500								
125	903.91-Cust Rec Exp-Delinq-Lab	903	Labor				29,277	9,143	3,124				
126	903.92-Cust Rec Exp-Delinq-OH	903	OH				40,571	5,755					
127	903.05-Cust Rec Exp-Delinq-Misc	903	Other							872,949	907,634	1,015,031	1,047,510
128	904.00-Uncollectable Accounts	904	Other		20,000					-	-	20,000	20,000
129													
130	**Total Cust accounting & collecting**			8,500	227,175	5,000	801,810	34,363	7,206	892,757	929,410	1,050,953	1,084,054
131													
132	**SALES PROMOTION Exp**												
133	908.00-Cust Assist-Exp	908	Other		1,000								
134	908.51-Cust Assist-Energy Audit-	908	Labor					120	41				
135	908.52-Cust Assist-Energy Audit-	908	OH					76					
136	908.05-Cust Assist-Energy Audit-	908	Other							2,030	180	1,227	1,237
137	909.00-Cust Service Info-Misc	909	Other		6,000					314	800	16,000	6,000
138	913.00-Advertising Exp	913	Other		2,500					1,738	2,191	2,500	2,500
139													
140	**Total Sales Promotion Exp**			-	9,500	-	-	196	41	4,082	3,171	19,727	9,737
141													

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Line	Account	#	Type	E&O 2026	Office 2026	Admin & Misc 2026	C&T Payroll 2026	Union Payroll 2026	Transportation 2026	Annual Totals, By Account 2023	2024	2025	2026
142	**ADMINISTRATIVE & Genl Exp**												
143	920.00-A&G Salaries	920	Labor			9,000							
144	920.01-A&G Salaries-Labor	920	Labor				349,797		3,000				
145	920.02-A&G Salaries-OH	920	OH				484,732						
146	920.03-A&G Salaries-Transp	920	Trans/Mat										
147	920.40-A&G-President-CEO	920	Labor	12,000									
148	920.50-A&G-V-P Fin Adminis	920	Labor			15,000							
149	920.60-A&G-V-P Eng Oper	920	Labor	15,000									
150	920.70-A&G- Staff	920	Labor		22,700					652,639	757,901	869,897	911,229
151	921.00-Off Supp & Exp	921	Other		5,540	6,000							
152	921.10-Off Supp & Exp-Utilities	921	Other			6,060							
153	921.40-Off Exp-Subs/Membershi	921	Other		3,400								
154	921.50-Off Exp-Off Supp	921	Other		23,260								
155	921.60-Off Exp-WECO Telephon	921	Other	-		49,500							
156	921.70-Off Exp-Dispatch Telepho	921	Other	86,000		4,800							
157	921.90-Off Exp-Misc	921	Other		17,700	2,360							
158	921.99-Off Exp-Working Capital C	921	Other			(94,910)				61,925	112,900	123,007	109,710
159	923.00-Outside Svc Empl	923	Other		3,925	25,400							
160	923.10-Outside Svc Empl-Auditor	923	Other			34,000							
161	923.20-Outside Svc Empl-Engine	923	Other	5,000									
162	923.30-Outside Svc Empl-Attorne	923	Other			25,000							
163	923.90-Outside Services Employe	923	Other			61,200				87,889	137,115	154,525	154,525
164	924.00-Property Insurance	924	Other			61,410				51,268	53,098	61,410	61,410
165	925.00-Injuries & Damages	925	Other							-	-	-	-
166	926.11-Employee Pen Ben-Healt	926	OH										
167	926.20-Empl Pen Ben-Postret He	926	OH										
168	926.70-Employee Pen Ben-Life Ir	926	OH										
169	926.99-Employee Pen Ben-SERF	926	OH							-	-	-	-
170	928.00-Regulatory Commission E	928	Other			43,000							
171	928.01-Rate Case Exp	928	Other			110,393				68,366	42,985	43,000	153,393
172	930.00-Directors Exp	930	Other			106,681							
173	930.11-Misc Gen Exp-GPS Map I	930	Other										
174	930.20-Misc Gen Exp-GPS Map-I	930	Labor	3,100									
175	930.21-Misc Gen Exp-GPS Map-(	930	Other										
176	930.22-Misc Gen Exp-GPS Mapp	930	OH										
177	930.24-Misc Gen Exp-GPS Mapp	930	Other										
178	930.25-Misc Gen Exp-Covid Expe	930	Other										
179	930.30-Misc Gen Exp- Misc	930	Other	800						105,355	84,404	99,751	110,581

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Expenses By Account and By Type
Year 2023, HY 2024, FTY 2025 and FPFTY 2026

Line	Account	#	Type	E&O 2026	Office 2026	Admin & Misc 2026	C&T Payroll 2026	Union Payroll 2026	Transportation 2026	Annual Totals, By Account 2023	2024	2025	2026
180	931.00-Rents	931	Other		2,200					2,442	3,611	2,200	2,200
181	932.00-Maint of Genl Property	932	Other	11,500		35,236							
182	932.01-Maint of Genl Property-La	932	Labor					8,299	2,836				
183	932.02-Maint of Genl Property-OH	932	OH					5,223					
184	932.10-Maint of Genl Property-Of	932	Other	11,000									
185	932.11-Maint Genl Prop-Off Bldg-	932	Labor										
186	932.12-Maint Genl Prop-Off Bldg-	932	OH										
187	932.20-Maint Genl-Communicatic	932	Other	500									
188	932.21-Maint Genl-Comm Equip-I	932	Labor										
189	932.22-Maint Genl-Comm Equip-(	932	OH										
190	932.30-Maint Gen Property-Plant	932	Other	12,550			-						
191	932.31-Maint Gen Prop-Plant Bld	932	Labor					1,201	410				
192	932.32-Maint Gen Prop-Plant Bld	932	OH					756					
193	932.41-Maint Gen Prop-Apt Hous	932	Labor										
194	932.42-Maint Gen Prop-Apt Hous	932	OH										
195	932.70-Maint Gen Office Equip	932	Other		3,800								
196	932.05-Maint Genl Property- Misc	932	Other							112,580	72,186	98,034	93,311
197				157,450	82,525	500,130	834,529	15,479	6,246				
198	**Total Administrative & Genl Exp**			157,450	82,525	500,130	834,529	15,479	6,246	1,142,464	1,264,200	1,451,824	1,596,359
199	Detail, adjusted for WC Claim												
200	**Total Operating Exp**			865,088	319,200	505,130	1,862,744	609,742	130,875	3,318,291	3,531,630	4,084,441	4,292,779
201	From OM									0	0	0	0
202	Adjustments												
203	Working Capital claim												
204	Rate case Exp												
205				865,088	319,200	505,130	1,862,744	609,742	130,875				
206	From OM												
207	From C1-1												
208	Differrence												
209													
210													
211	Labor		Labor	50,600	22,700	24,000	780,779	355,281	124,403				
212	OH		OH	172,200	-	-	1,081,965	206,791	-				
213	Trans/Mat		Trans/Ma	3,000	-	-	-	31,550	6,472				
214	Other		Other	639,288	296,500	481,130	-	16,120	-				
215	WC		WC	-	-	-	-	-	-				
216				865,088	319,200	505,130	1,862,744	609,742	130,875				

WP_C2 (R)

Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026 (R)
Expenses By Account
Year 2013, HY 2024, FTY 2025 and FPFTY 2026

Line	Acct.	Account Description	Labor 12/31/23	Labor 12/31/24	Labor 12/31/25	Labor 12/31/26	OH 12/31/23	OH 12/31/24	OH 12/31/25	OH 12/31/26
1		Other Power Supply Expenses:								
2	555	Power Purchased	$0	$0	$0	$0	$0	$0	$0	$0
3		*Total Other Power Supply Expenses*	0	0	0	0	0	0	0	0
4										
5		Distribution Expenses								
6	580	Operations Supv & Eng	0	4,043	0	0	0	4,078	0	0
7	582	Station Expense	0	0	0	0	0	0	0	0
8	583	Overhead Line Expense	(2,379)	(1,766)	3,980	4,098	3,064	2,535	1,814	1,922
9	585	Street Lighting Expense	0	127	178	182	675	19	81	85
10	586	Meter Expense	19,146	21,287	26,220	26,981	14,498	15,697	11,725	12,422
11	587	Customer Installation Expense	0	109	178	182	0	98	81	85
12	588	Miscellaneous Distribution Expense	86,318	91,107	136,556	140,466	71,468	67,581	122,066	123,422
13	589	Rents	0	0	0	0	0	0	0	0
14		*Total Operation*	103,085	114,906	167,111	171,910	89,705	90,009	135,767	137,936
15										
16	590	Maint Supv & Eng	37,403	41,204	41,076	42,663	48,308	56,671	59,695	59,121
17	591	Maintenance of Structures	792	0	0	0	0	0	0	0
18	592	Maintenance of Station Equipment	3,834	1,589	1,869	1,924	1,863	1,621	2,702	126,752
19	593	Maintenance of Overhead Lines	235,059	230,070	306,503	314,995	133,958	131,403	124,896	131,755
20	594	Maintenance of Underground Lines	3,598	4,482	4,503	4,638	1,588	2,645	2,053	2,175
21	595	Maintain Line Transformers	1,742	3,059	3,347	3,447	949	1,358	1,526	1,617
22	596	Maint. Street Light & Signal Expense	1,700	962	623	641	1,291	650	284	301
23	597	Maintenance of Misc. Distribution Plai	63,480	56,551	35,036	36,073	9,842	7,010	43,172	44,121
24		*Total Maintenance*	347,607	337,918	392,958	404,383	197,799	201,357	234,328	365,842
25		*Total Distribution Expenses*	450,692	452,824	560,069	576,293	287,504	291,366	370,095	503,778
26										
27		Customer Accounting & Collection Expenses:								
28	902	Meter Reading Expense	10,767	12,359	10,936	11,261	9,042	9,416	4,986	5,283
29	903	Customer Records & Collection Exp	307,531	309,910	330,520	353,116	386,234	405,873	463,836	473,719
30	904	Uncollectible Accounts	0	0	0	0	0	0	0	0
31		*Total Customer Accounting & Collecti*	318,298	322,269	341,456	364,377	395,275	415,289	468,822	479,002
32										
33	908	Cust Assist-Energy Audit-Misc	1,735	180	156	161	0	0	71	76
34	909	Cust Service Info-Misc	0	0	0	0	0	0	0	0
35	913	Advertising Exp	0	0	0	0	0	0	0	0
36	908-913	Safety and Communications	1,735	180	156	161	0	0	71	76
37										

WP_C2 (R)

Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026 (R)
Expenses By Account
Year 2013, HY 2024, FTY 2025 and FPFTY 2026

Line	Acct.	Account Description	Labor 12/31/23	Labor 12/31/24	Labor 12/31/25	Labor 12/31/26	OH 12/31/23	OH 12/31/24	OH 12/31/25	OH 12/31/26
38		Administrative & General Expenses:								
39	920	Administrative & General Salaries	301,608	355,049	401,562	426,497	351,031	402,852	468,335	484,732
40	921	Office Supplies & Expenses	0	0	0	0	0	0	0	0
41	923	Outside Services Employed	0	0	0	0	0	0	0	0
42	924	Property Insurance	0	0	0	0	0	0	0	0
43	926	Employee Pensions & Benefits	0	0	0	0	0	0	0	0
44	928	Regulatory commission expenses	0	0	0	0	0	0	0	0
45	930	Miscellaneous General Expense	3,074	0	3,100	3,100	0	0	0	0
46	931	Rents	0	0	0	0	0	0	0	0
47	932	Maintenance of general plant	50,565	11,364	12,378	12,746	0	0	5,643	5,979
48		*Total Administrative & General Expen*	355,248	366,413	417,040	442,344	351,031	402,852	473,978	490,711
49										
50		**Total Operating & Maintenance Ex**	**$1,125,972**	**$1,141,685**	**$1,318,721**	**$1,383,174**	**$1,033,810**	**$1,109,508**	**$1,312,966**	**$1,473,567**

WP_C2 (R)

Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026 (R)
Expenses By Account
Year 2013, HY 2024, FTY 2025 and FPFTY 2026

Line	Acct.	Account Description	Trans/Mat 12/31/23	Trans/Mat 12/31/24	Trans/Mat 12/31/25	Trans/Mat 12/31/26	Other 12/31/23	Other 12/31/24	Other 12/31/25	Other 12/31/26	Total 12/31/23	Total 12/31/24	Total 12/31/25	Total 12/31/26
1		Other Power Supply Expenses:												
2	555	Power Purchased	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
3		*Total Other Power Supply Expenses*	0	0	0	0	0	0	0	0	0	0	0	0
4														
5		Distribution Expenses												
6	580	Operations Supv & Eng	0	0	0	0	0	0	0	0	0	8,121	0	0
7	582	Station Expense	0	0	0	0	0	0	0	0	0	0	0	0
8	583	Overhead Line Expense	0	0	0	0	0	0	0	0	686	770	5,794	6,020
9	585	Street Lighting Expense	0	0	0	0	0	0	0	0	675	146	259	267
10	586	Meter Expense	0	0	0	0	0	0	500	500	33,644	36,983	38,445	39,903
11	587	Customer Installation Expense	0	0	0	0	0	0	0	0	0	206	259	267
12	588	Miscellaneous Distribution Expense	0	699	0	0	12,886	14,556	21,800	21,800	170,671	173,944	280,422	285,688
13	589	Rents	0	0	0	0	30,717	32,950	35,300	35,300	30,717	32,950	35,300	35,300
14		*Total Operation*	0	699	0	0	43,603	47,507	57,600	57,600	236,392	253,121	360,478	367,446
15														
16	590	Maint Supv & Eng	0	0	0	0	0	0	0	0	85,710	97,875	100,771	101,784
17	591	Maintenance of Structures	1,056	0	0	0	0	0	0	0	1,848	0	0	0
18	592	Maintenance of Station Equipment	0	0	0	0	0	0	0	(110,119)	5,697	3,210	4,571	18,557
19	593	Maintenance of Overhead Lines	767	0	0	(0)	466,984	508,315	537,673	538,577	836,769	869,788	969,072	985,327
20	594	Maintenance of Underground Lines	0	0	0	0	23,250	23,079	33,500	33,500	28,436	30,206	40,056	40,313
21	595	Maintain Line Transformers	2,987	10,115	3,000	3,000	0	0	0	0	5,677	14,532	7,873	8,064
22	596	Maint. Street Light & Signal Expense	0	0	0	0	0	0	0	0	2,991	1,612	907	942
23	597	Maintenance of Misc. Distribution Pla	(529)	8	0	0	2,674	937	0	0	75,467	64,505	78,208	80,194
24		*Total Maintenance*	4,281	10,123	3,000	3,000	492,908	532,331	571,173	461,958	1,042,595	1,081,729	1,201,459	1,235,182
25		*Total Distribution Expenses*	4,281	10,822	3,000	3,000	536,511	579,837	628,773	519,558	1,278,988	1,334,849	1,561,937	1,602,629
26														
27		Customer Accounting & Collection Expenses:												
28	902	Meter Reading Expense	0	0	0	0	0	0	0	0	19,808	21,775	15,922	16,544
29	903	Customer Records & Collection Exp	0	0	0	0	179,184	191,852	220,675	220,675	872,949	907,634	1,015,031	1,047,510
30	904	Uncollectible Accounts	0	0	0	0	0	0	20,000	20,000	0	0	20,000	20,000
31		*Total Customer Accounting & Collecti*	0	0	0	0	179,184	191,852	240,675	240,675	892,757	929,410	1,050,953	1,084,054
32														
33	908	Cust Assist-Energy Audit-Misc	0	0	0	0	295	0	1,000	1,000	2,030	180	1,227	1,237
34	909	Cust Service Info-Misc	0	0	0	0	314	800	16,000	6,000	314	800	16,000	6,000
35	913	Advertising Exp	0	0	0	0	1,738	2,191	2,500	2,500	1,738	2,191	2,500	2,500
36	908-913	Safety and Communications	0	0	0	0	2,347	2,991	19,500	9,500	4,082	3,171	19,727	9,737
37														

WP_C2 (R)

Wellsboro Electric Company
Rate Case with Fully Projected Future Test Year 2026 (R)
Expenses By Account
Year 2013, HY 2024, FTY 2025 and FPFTY 2026

Line	Acct.	Account Description	Trans/Mat 12/31/23	Trans/Mat 12/31/24	Trans/Mat 12/31/25	Trans/Mat 12/31/26	Other 12/31/23	Other 12/31/24	Other 12/31/25	Other 12/31/26	Total 12/31/23	Total 12/31/24	Total 12/31/25	Total 12/31/26
38		Administrative & General Expenses:												
39	920	Administrative & General Salaries	0	0	0	0	0	0	0	0	652,639	757,901	869,897	911,229
40	921	Office Supplies & Expenses	0	0	0	0	61,925	112,900	123,007	109,710	61,925	112,900	123,007	109,710
41	923	Outside Services Employed	0	0	0	0	87,889	137,115	154,525	154,525	87,889	137,115	154,525	154,525
42	924	Property Insurance	0	0	0	0	51,268	53,098	61,410	61,410	51,268	53,098	61,410	61,410
43	926	Employee Pensions & Benefits	0	0	0	0	0	0	0	0	0	0	0	0
44	928	Regulatory commission expenses	0	0	0	0	68,366	42,985	43,000	153,393	68,366	42,985	43,000	153,393
45	930	Miscellaneous General Expense	0	0	0	0	102,281	84,404	96,651	107,481	105,355	84,404	99,751	110,581
46	931	Rents	0	0	0	0	2,442	3,611	2,200	2,200	2,442	3,611	2,200	2,200
47	932	Maintenance of general plant	0	0	0	0	62,014	60,822	80,013	74,586	112,580	72,186	98,034	93,311
48		*Total Administrative & General Expen*	0	0	0	0	436,186	494,935	560,806	663,305	1,142,464	1,264,200	1,451,824	1,596,359
49														
50		**Total Operating & Maintenance Ex**	**$4,281**	**$10,822**	**$3,000**	**$3,000**	**$1,154,228**	**$1,269,615**	**$1,449,754**	**$1,433,038**	**$3,318,291**	**$3,531,630**	**$4,084,441**	**$4,292,779**
											3,318,291	3,531,630	4,084,441	4,292,779

WP_C3 (R) **Wellsboro Electric Company**

Rate Case with Fully Projected Future Test Year 2026 (R)

Workpaper 2 to Schedule C

Accumulated Deferred Income Taxes

Years 2024 through 2026

Line	**WECO**	**2024**	**2025**	**2026**
1				
2	Book	15,226,786	17,226,319	19,321,064
3				
4	Federal Tax - MACRS	26,171,198	28,090,123	30,042,650
5				
6	Federal Tax - SL	26,630,508	28,182,113	29,858,231
7				
8	PA Tax	20,882,587	23,059,206	25,254,821
9				
10	Federal Tax Depr Exp - MACRS	1,979,408	1,918,925	1,952,528
11				
12	Federal Tax Depr Exp - SL	1,598,164	1,551,605	1,676,119
13				
14	PA Tax Depr Exp	2,466,799	2,176,619	2,195,614
15				
16				
17				
18				
19				
20				

BEFORE

THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	**:**	
	:	
v.	**:**	**Docket No. R-2025-3054392**
	:	
Wellsboro Electric Company	**:**	

SURREBUTTAL TESTIMONY

OF

HOWARD S. GORMAN

ON BEHALF OF

WELLSBORO ELECTRIC COMPANY

AUGUST 28, 2025

BEFORE

THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	**:**	
	:	
v.	**:**	**Docket No. R-2025-3054392**
	:	
Wellsboro Electric Company	**:**	

SURREBUTTAL TESTIMONY OF HOWARD S. GORMAN ON BEHALF OF WELLSBORO ELECTRIC COMPANY

Q. Please state your name, occupation and business address.

A. My name is Howard Gorman. I am the President of HSG Group, Inc., a consulting firm specializing in utility rate and regulatory matters, located in Great Neck, NY.

Q. Are you the same Howard Gorman that provided Direct Testimony on behalf of Wellsboro Electric Company ("Wellsboro" or "Company")?

A. Yes. Terms defined in my Direct Testimony or my Rebuttal Testimony have the same meaning in this Surrebuttal Testimony.

Q. What is the purpose of your testimony today?

A. The purpose of my testimony is to respond to the Rebuttal Testimony of the following witnesses:

- Office of Consumer Advocate ("OCA") Witness Myer (OCA St. 1R)
- OCA Witness Deupree (OCA St. 3R)

Q. Are you sponsoring any exhibits today?

A. No.

Q. Are you supporting any changes to the Company's filing, as amended by Exhibit___(HSG-1R)?

A. No.

Q. Please summarize your review of the Rebuttal Testimony of Mr. Meyer (OCA St. 1R) and Mr. Deupree (OCA St. 3R).

A. Except for Mr. Deupree's discussion of the Company's Customer Cost Analysis, which I address immediately below, neither Mr. Meyer nor Mr. Deupree raise any new issues or provide any new arguments for their positions.

Mr. Meyer addresses two adjustments that were suggested in the Direct Testimony by other parties. Wellsboro accepted one of those adjustments (Tax Rate). I addressed the other adjustment (Unamortized Rate Case Expense) in my Rebuttal Testimony. Mr. Meyer has not raised any arguments that I have not fully refuted.

Q. What did Mr. Deupree say regarding the Company's Customer Costs Analysis?

A. Mr. Deupree repeated his objection to any increase in the monthly Customer charges (OCA St. 3R, p. 4). I will address the specifics of his testimony below:

- Mr. Deupree opines that the Customer Cost Analysis should be based on the Rate of Return ("ROR") at present rates of 0.68%, because the Commission has not approved its requested ROR or that of any other witness (OCA St. 3R, p. 3). This approach does not make sense. First, Mr. Deupree is implicitly accepting the Company's computation of its revenue requirement, but the Commission has not accepted that either. Second, we are establishing the rates for a Fully Projected Future Test Year assuming that a rate increase will be granted. Using the existing ROR without consideration of the rate relief is inconsistent with this process. Third, the rates and revenues currently charged

by the Company are too low; that is why a rate case was filed, so using the existing ROR only perpetuates the shortfall. What if the Company had been producing a negative ROR; would Mr. Deupree advocate using a negative ROR to set new rates?

- Mr. Deupree compared the Company's current Customer Charges to Customer-Related Costs computed using the ROR proposed by the Bureau of Investigation and Enforcement ("I&E") Witness Walters, 7.13%; and computed that current Customer Charges for Rate Schedules Residential Service ("RS"), Residential Service All Electric ("RSAE"), Non-Residential Service ("NRS"), and Non-Residential Heating ("NRH") recover approximately 69%-70% of Customer-Related Costs; and therefore in his view there is no "pressing need to increase" Customer Charges for Residential or Commercial classes (OCA St. 3R, p. 4). For the reasons stated in my prior testimony, it is important that Customer Charges reflect costs, and this view is supported by prior guidance from the Commission, including the UGI 2017 Order, p. 173, where the Commission said, "Thus, we find that UGI's proposal is consistent with *Lloyd*, which held that rate structures should be adjusted to reflect the cost of service to each rate class and to eliminate cross-subsidization." There is no authority or rationale to substitute Mr. Deupree's judgment that the current monthly Customer Charges are "good enough" for ratemaking and economic theory and practice and the guidance of the Commission regarding the appropriate method to establish customer charges.
- Finally, Mr. D'Ascendis has explained why OCA Witness Walters' ROR recommendation is unreasonably low and not appropriate to establish rates in this proceeding.

I recommend the Commission evaluate the Company's proposed Customer Charges based on the information it has filed in this case, Exhibit___(HSG-1R), and the principles which have been established by precedents.

Q. Does this conclude your Surrebuttal Testimony today?

A. Yes.

BEFORE

THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	**:**	
	:	
v.	**:**	**Docket No. R-2025-_____**
	:	
Wellsboro Electric Company	**:**	

DIRECT TESTIMONY
AND EXHIBITS

OF

BYRON FARNSWORTH, JR.

ON BEHALF OF

WELLSBORO ELECTRIC COMPANY

APRIL 30, 2025

BEFORE

THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	**:**	
	:	
v.	**:**	**Docket No. R-2025-**
	:	
Wellsboro Electric Company	**:**	

DIRECT TESTIMONY OF BYRON FARNSWORTH, JR.
ON BEHALF OF WELLSBORO ELECTRIC COMPANY

Q. Please state your name and business address.

A. My name is Byron (Barney) Farnsworth, Jr., and my business address is 33 Austin Street, Wellsboro, Pennsylvania.

Q. By whom are you employed and what position do you hold with Wellsboro Electric Company?

A. I am employed by C&T Enterprises, Inc. ("C&T"), and assigned to Wellsboro Electric Company ("Wellsboro" or "Company") as the President and Chief Executive Officer.

Q. What are your duties in that capacity?

A. My duties are to lead and provide general management to Wellsboro. I am also responsible for strategic direction, power supply and regulatory/legislative issues at Wellsboro.

Q. Please describe your educational background and professional background.

A. I have a Bachelor's Degree in electrical engineering from the Rochester Institute of Technology and a Masters Degree from Rochester Institute of Technology with concentrations in Management and Finance. I previously worked at Rochester Gas & Electric and NYSEG for over 23 years in varying roles that increased in responsibility. I

started as a lineman moved into engineering and into Power Control as an Energy Scheduler/Forecaster. In 1996, RG&E formed an unregulated company and I was brought in to build out the electric and natural gas supply, pricing models and risk management functions and assumed the same duties for NYSEG Solutions in 2004. During 2008, I started at MXEnergy and worked in the retail space in Executive roles managing supply, pricing and risk management for various EGS's until I was hired by Wellsboro Electric Company in July 2018 as the VP, Engineering & Operations/ COO. I became Wellsboro's President and CEO in January 2020.

Q. Please describe the purpose of your testimony.

A. My testimony starts with a general overview of Wellsboro, its service territory, and its customer base. Then, I will address historical and future test year expenditures and capital improvement information provided to HSG Group, Inc. ("HSG Group") for compilation and preparation of Wellsboro's filing. This will include the Wellsboro labor costs for both union and non-union employees. Additionally, I will outline the factors supporting a performance adjustment to Wellsboro's rate of return. Finally, I will discuss the proposed changes to Wellsboro's tariff.

COMPANY BACKGROUND AND OVERVIEW

Q. Please provide a brief overview of Wellsboro and its service territory.

A. Wellsboro is a small investor-owned Electric Distribution Company ("EDC") under the jurisdiction of the Pennsylvania Public Utility Commission ("PUC" or "Commission") operating in the Borough of Wellsboro and surrounding areas in Tioga County. The Company's service territory is predominately rural. We have over 550 miles of distribution facilities and provide service to approximately 6,478 customers as of December 31, 2024,

of whom 5,159 were residential, and 1,319 were commercial, industrial, lighting or sales for resale.

Wellsboro has been providing electric service to consumers in Tioga County since 1894, with a variety of owners and shareholders since then. In 1995, Wilderness Utilities, Inc., acquired all of Wellsboro's common stock from members of the McCarthy Family, which had owned the majority of the Company since 1984. Wilderness was a holding company formed by Tri-County Rural Electric Cooperative ("Tri-County") for the purpose of acquiring and owning Wellsboro.

On January 1, 2005, Wellsboro transferred 100% of its common stock in Wellsboro to C&T and Wilderness was then inactivated. C&T is a holding company and management services firm that is jointly owned by Tri-County, based in Mansfield, Pennsylvania, and Claverack Rural Electric Cooperative based in Wysox, Pennsylvania. C&T is also the parent corporation of Citizens' Electric Company of Lewisburg, PA ("Citizens'"), and Valley Energy, Inc. ("Valley"). We obtained the Pennsylvania Public Utility Commission's ("PUC" or "Commission") approval for the transfer of control and ownership from Wilderness to C&T on December 23, 2004, at Docket No. A-111200F000.

Q. What changes were made to the Company's tariff or operations as a result of the Electric Generation Customer Choice and Competition Act ("Competition Act")?

A. Wellsboro unbundled its generation supply service from its electric distribution service. Electric distribution service remains a service that is regulated by the Commission pursuant to traditional ratemaking processes under Chapter 13 of the Public Utility Code. This filing implements proposed changes to our unbundled distribution rates in accordance with the Chapter 13 requirements and process.

Wellsboro retains the obligation to provide generation supply service to all customers as the Default Service Provider ("DSP") in its service territory in conformance with requirements set forth in the Competition Act. The generation rate is known as our Generation Supply Service Rate ("GSSR"), which includes the GSSR-1 and GSSR-2. We are proposing a minor change to our GSSR-1 and GSSR-2 Riders in this proceeding to ensure that customer generators are charged for distribution and generation service using a consistent measure of their use of the system (e.g., Billing Demand). I will address this in more detail later in my testimony.

Q. Do the proposed distribution rates include any expenses related to generation supply?

A. No. HSG Group's analysis focused solely on our regulated distribution service rates. As a result, both the revenues and expenses related to generation supply services in the historic, future, and fully-projected future test years (HTY, FTY and FPFTY) are removed from our overall revenue and expenses.

In addition, the legal and consulting fees that Wellsboro incurs for the generation function are collected through the GSSR and were not included in the distribution rates in this filing. Finally, our cash working capital assumption for the new distribution rates is based only on the portion of the expenses and bills related to distribution service and does not include generation expenses.

Q. When was Wellsboro's last base rate proceeding?

A. Wellsboro's last base rate proceeding was in 2019, with rates taking effect in early May 2020. It has been approximately six years since Wellsboro filed the last distribution rate increase.

Q. Can you explain generally the changes that have occurred since the last case?

A. Yes. Many elements of our financial and operational environment have changed in six years, especially during the COVID-19 pandemic and its aftermath. We were able to avoid filing for a rate case because we pursued cost management strategies, searched for available grants and experienced a few new customer installations; however, the cumulative impact of slowing growth and increasing costs now require us to seek a rate increase.

First, there has been substantial inflation in the cost of materials and equipment over that time. During the COVID-19 pandemic and into 2023, the United States economy experienced Consumer Price Index (CPI) inflation that peaked at about 9.1% year over year in June 2022 and remained above 4% through mid-2023 and has remained on average above 3.5% in late 2023 through 2024. The Headline Producer Price Index (Total) (PPI), which reflects the prices that companies are receiving for their products, peaked at 11.2% for the 12-month measure in March 2022. Although inflation has moderated, this only reduces the rate of growth going forward for our materials and supplies—it does not reduce the costs back to the 2019 levels.

Second, our labor costs and benefits have increased since 2019. I will discuss in more detail later how our union and non-union wages have increased. Our increases are consistent with those seen in other industries, as reported by the Bureau of Labor Statistics. Based on information on their website, the year over year inflation to wages and salaries exceeded 4% beginning in the September 2020 through September 2021 period and continuing for each yearly survey period thereafter through the June 2023 to June 2024 survey period.

Third, our outside contractor expenses for tree-trimming and other reliability enhancing activities also have increased due to the Commission's emphasis on service reliability. In

general, vegetation management and routine maintenance on our overhead lines is reflected in our operating expenses in Accounts 588 and 593. Mr. Gorman's Exhibit __ (HSG-1), Schedule C1-1 provides an illustration of how our actual expenses increased from calendar year 2023 through calendar year 2026. Since our last rate change took effect in 2020, our Operating & Maintenance Expenses increased by $ 98,513 from $1,236,336 in 2020 to $1,334,849 in 2024. We are projecting further increases in 2025 and 2026 to focus on additional vegetation management, new technology to manage outages, customer information and billing.

Similarly, our Administrative & General Expenses and our Customer Account and Collection Expenses have increased, as reflected in Mr. Gorman's analysis.

In addition, Wellsboro has also completed numerous projects to upgrade and modernize its distribution system that were necessary to maintain service and reliability, including the replacement of our antiquated office and crew building. These improvements will be placed into rate base as a part of this proceeding.

Q. What has the Company done to mitigate those increases?

A. We have searched for areas where costs can be reduced through greater efficiency or outsourcing. We have continued to expand our use of the NISC system (CIS, OMS, material management, staking/mapping, budgeting and financial data) since 2019. Employees have been going through training each year to continuously develop their skills on our NISC system which has increased productivity and efficiency since 2019. Employees have also been cross-training to increase our collective knowledge and the coverage as employees are out of the office for vacations and training while planning for potential Succession. Increased use of existing technology has been deployed for Work

Management (Work orders and meter orders) by our linemen in addition they perform PUC mandated Inspection and Maintenance (I&M) work each year. Tablets are used to record I&M data (pole inspections, pole pulls, line inspections, transformer inspections, miscellaneous inspections) in the field and then it is brought back to the office and all data is uploaded into our NISC system as a permanent record which has eliminated the use of paper that was used prior to 2019. We completed required voltage conversion work and installed any remaining automated meters during the Spring of 2019 and have been 100% AMI since late 2019. We are using the AMI meters as of 2024 to transmit voltages multiple times a day into a report to help us continually monitor and identify potential issues on our system in advance of customers calling. The voltage report has reduced the need to send personnel into the field to install/remove a recording device. All of the technology adoptions have enabled us to keep the work force focused and efficient while avoiding the need for additional employees. The enhancements have improved the system reliability, resilience and ultimately the service to customers which has been demonstrated in survey results. Wellsboro collaborates with Citizens' and other PA EDCs on best practices for Engineering, Operations, Customer Service and Regulatory/Legislative issues.

COMPANY PERFORMANCE

Q. In Statement No. 2, the Direct Testimony of Dylan D'Ascendis and Ryan Kucan, Mr. D'Ascendis and Mr. Kucan propose both a size adjustment and a performance adjustment to their recommended rate of return. Do you agree with their approach?

A. Yes. A size adjustment and a performance adjustment are both appropriate.

Q. What is the basis for the performance adjustments proposed by Mr. D'Ascendis and Mr. Kucan?

A. As a basis for the performance adjustment, Mr. D'Ascendis and Mr. Kucan reference Section 523 of the Public Utility Code, which outlines the factors considered by the Commission in awarding performance adjustments. I am advised by counsel that the Public Utility Code identifies several criteria to be considered in assessing the performance of a fixed utility for purposes of a performance factor adjustment, including consideration of any relevant and material evidence of efficiency, effectiveness, and adequacy of service. The Commission should approve a performance adjustment based on Wellsboro's performance in the following areas:

- **Excellent reliability metrics.** Wellsboro has met or exceeded all PUC reliability metrics as shown in the Quarterly Reliability Dashboard Report for 4th Quarter 2024 attached as Exhibit __ (BF-1). Additionally, Exhibit __ (BF-2) contains Wellsboro's 2024 Annual Reliability Report, which similarly shows Wellsboro complying with PUC guidelines and exceeding the performance of the other EDCs regulated by the Commission. The 2024 report also includes reliability metrics for the prior two years (2022-2023).
- **Low customer complaints.** For the period 2022-2024, Wellsboro received no formal complaints and 10 informal complaints.
- **Favorable customer feedback.** Wellsboro has seen a steady improvement in positive reviews and evaluations from its customers since 2019. The Annual Customer Contact surveys for the period 2022-2024 are attached as Exhibit __ (BF-3).

- **High responsiveness: customer support calls.** Records from the Commission's Quality of Service System attached as Exhibit __ (BF-4) show Wellsboro answered, on average, approximately 97% of its customer phone calls in 2024 within 30 seconds.
- **Significant capital investment.** Addressed later in my testimony, Wellsboro continues to invest approximately $2.02 million annually in system replacements and improvements. This calculation does not include the building project. Exhibit __ (BF-5) shows three years of capital results and YTD 2025 is tracking closely to $2.00 million. There was roughly 1 project per year driven by customer requests that were close to $1.0M and almost wholly paid by customers from 2021 through 2024. There were multiple fiber providers that came through our territory in 2020 and 2021 that saw roughly 200 pole replacements that were paid in entirety by the attachers. The Commission should note these investments were funded without reliance on a Distribution System Improvement Charge.
- **Technology adoption: Smarthub use.** A total of 2,706 customers (approximately forty-two percent (42%) of Wellsboro's total customer count) use Smarthub to review and pay bills electronically, review usage reports, track outages, and remain connected to the Company's services via a mobile application or the website. Smarthub is available 24 hours a day for the convenience of Wellsboro’s customers.
- **Very low reportable injuries.** Wellsboro had zero (0) reportable injuries or MVA’s from 2019 through 2024, as demonstrated by the OSHA Form 300A attached as Exhibit __ (BF-6).

- **Street Light Upgrades.** Wellsboro received Commission approval for its LED tariff in 2019 and completed the subsequent LED fixture replacements in December 2023. The LED conversion has significantly reduced street light maintenance and the energy consumption when compared to older mercury vapor and sodium lighting fixtures.

CAPITAL IMPROVEMENTS AND PROJECTS

Q. Could you please describe some of the distribution system projects Wellsboro has completed since the Company's last rate case?

A. Yes. In addition to ongoing maintenance and operations, the Company has invested an average of $2.2million per year in capital improvements and expansions since the last rate case, not including the new office and crew building. When Wilderness purchased Wellsboro in 1995, the distribution system needed much repair. Since 1995, Wellsboro has invested over $36.6 million in system improvements and repairs. The Company continues a long-term effort to maintain and upgrade our distribution system. These plant investments were in the form of replacing its aging distribution infrastructure, including reconductoring and installing three-phase tie-points on select lines, increasing pole replacements towards a target of 250-300 per year, replacing aging porcelain equipment, installing switches and vacuum reclosers to automate the isolation of faults to reduce customer outages, performing improvements that will enable future voltage conversions and completing other reliability-enhancing improvements.

Finally, since the last rate case, we completed the upgrade of the FirstEnergy Mid-Atlantic Interstate Transmission Company (“FE MAIT”) transmission facility that serves our service territory. As part of the last rate case, we committed to undertake required

substation and transmission work that cost approximately $980,000 to ensure that the FE MAIT would upgrade the line feeding our substation from 34.5 kV to 115 kV. This service voltage conversion increased the reliability for our customers and also has helped us to avoid approximately $365,000 a year that we were paying to FE MAIT for the 35 kV connection. Since the new 115 kV line was energized in September 2020, the Wellsboro customers have avoided approximately $1,642,500 in extra transmission costs ($365,000 x 4.5 years).

Q. Please discuss Wellsboro's office and crew building project.

A. Wellsboro was formed in 1894 and some of the facilities dated back to its inception and others were built in the 1940s and 1950s and a small portion of the facility was remodeled in 1992. The main building was the old coal generating plant which had multiple roof leaks, exterior brick and mortar were failing, site drainage was poor, the property was exposed to an oil spill, the heating and cooling systems were obsolete and began failing in 2021 and some finally quit working in 2022. We began the process to evaluate moving to a new site, remodeling the old structures or building new structures in mid-2021. As we proceeded, the consensus was to remove the old buildings in phases and begin building new structures in phases. Phase 1 started in early 2023 and was completed in November 2023. Phase 1 encompassed dismantling our pole yard and an old substation adjacent to the pole yard and then a new steel building was built to house our linemen, vehicles, pole yard and the installation of oil containment pads. Phase 2 was started in November 2023, to remove asbestos roofing to clear the way for demolition of the area we had stored trucks and the linemen in over the years. Demolition of the brick and steel exo-skeleton began in December 2023 and we quickly found several significant issues in the old structures. The

roofing was riddled in holes, many pieces of steel in the building sagged once the brick supporting it was removed. The old brick and mortar were in such disrepair that large sections of wall fell or began sagging during demolition. The decision to build a new space optimized office was proven wise during the demolition process. The new office was completed to the point we could move out of our old space and into the new office in early November 2024. The last structure (old office) had asbestos roofing removed and demolition work started in December 2024. January and February 2025 were extremely cold so the final pieces of the building project (landscaping and the topcoat of blacktop) were shutdown until April/May 2025.

Q. Please provide some examples of projects that the Company is undertaking.

A. Significant 2025 capital projects include:

- **Hilltop Substation:** Wellsboro is working with our external engineering company to design a new exit for 5 of our 8 circuits that exit the substation built with Hendrix material on single pole structures with long spans. The project will construct 2 circuits onto a new steel structure reducing the span length using open wire construction. The project will be bid out in late 2025 for the material and a contractor in preparation to perform the work in the Spring of 2026. This project will enable the Company to reduce exposure to the loss of one structure that would impact over 4,000 customers (62%) and expose them to a lengthy outage as repairs are made.
- **Pole Replacements:** Wellsboro has experienced a high failure rate during pole testing (10-15%) from 2018-2023. There have been roughly 300 red tag replacements completed each year representing roughly 2.5% (15% of system). The

2024 testing dropped to a 6% failure rate which is requiring only 150 red tag pole replacements. Replacing poles that are beyond their useful life has improved reliability and we're expecting the failure rate to trend down toward 1-2% in the next few years. This reduction in pole replacements will enable capital to be shifted toward more reconductoring work identified in our 20-year work plan.

- **EATON Regulator upgrades:** Wellsboro has new Eaton Quik Drive Regulators to install that will help stabilize voltage anomalies.
- **Voltage Conversion:** Wellsboro will complete a voltage conversion (2.4/7.2 kV) in 2025 that is associated with a 3-phase tie-point project that started in 2025 and is expected to be finished in 2026. The conversion work will construct a new single-phase tie and setup future conversion work for roughly 150 customers. The work will improve reliability and help reduce the line losses on our system.
- **SCADA:** The SCADA was installed in December 2023 and is receiving substation data on transformers, reclosers and metering. Wellsboro has been approved for a PA Department of Environmental Protection ("DEP") Grid Resilience Grant to install new self-healing reclosers on a portion of our system that a loop constructed at the completion of a 2023 tie-point project. The new self-healing reclosers are expected to be installed in late 2025 or in early 2026 and will be interfaced into our SCADA. This equipment will enable devices to communicate with each other and reconfigure the circuit within a few minutes and then isolate a faulted area. This would be a significant improvement to reliability and resilience.
- **3-Phase Tie-Point and Reconductoring:** We have built 5 tie-points since 2019 that connect at minimum of 2 circuits together, which has enabled customers on

most of our system to have an alternate feed during storms, MVA or planned work situations. The 2025 tie-point work will connect the last circuit to an alternate feed. The work consists of several new poles, a 1-mile section of 3-phase line built with a larger conductor and a 1-mile 3-phase line reconductor to larger conductor. The remaining 1 mile of new 3-phase line is planned for completion in 2026. There is another 1-mile section of 3-phase line reconductor work that will be replaced in 2025 with a larger conductor on another circuit. This work will enhance the carrying capacity when the line needs to be reconfigured during a storm, MVA or planned work. Wellsboro developed a 20-year work plan in 2023 that has been used to keep the Company focused on future Capital improvements (reconductoring, new lines, replacing obsolete equipment in 2026 and out into the 2030's.

- Porcelain Replacements: Wellsboro started a project in 2022 to replace porcelain line cutouts, line arrestors and dead-end bells that fail unexpectedly causing outages. The project is roughly 60% completed at the end of 2024. The porcelain replacement will continue in 2025 and is expected to be completed in 2027.

Q. Do you anticipate that the rate of capital improvements will continue?

A. Yes. Wellsboro has a 5-year work plan that includes additional improvements. The projects for 2025 and 2026 are included in Mr. Gorman's analysis. A copy of our 5-year work plan is included in the budget that is provided as Wellsboro Confidential Exhibit 2.

Q. Does Wellsboro face any significant vegetation management issues?

A. Yes. Wellsboro's annual tree-trimming contractor costs have increased steadily by over $50,000-80,000 depending on the year due to contractor cost increases over the past three years. The Emerald Ash Borer and Pine Beetle removals, and enhanced tree growth in On

and Off ROW's due to wet growing seasons has impacted tree trimming costs the past few years. Vegetation management activities are particularly critical in a rural territory like Wellsboro's, which has many miles of off-road rights-of-way carrying poles and wires. Another significant issue is limited, qualified vegetation contractor interest due to the relatively small size of our contracts. Wellsboro implemented a multi-year bid process back in 2020 that enables the Company to control costs over the bid period which allowed us to bring our trimming back near a 5-year cycle.

Q. Are you planning to increase the tree trimming in 2025 and beyond?

A. Yes. We have included enhanced tree trimming objectives for 2025 and 2026, targeting $25,000/year of dead Off-rights-of-way trees that are leaning toward our 3-phase lines. If the tree trimming expense claim is fully reflected in our rates in this proceeding, we intend to continue this enhanced vegetation management rate.

Q. Are Wellsboro's operations, maintenance and replacement practices resulting in safe, adequate and reliable service to customers?

A. Yes. Wellsboro has demonstrated strong performance as measured by the Company's SAIDI (System Average Interruption Duration Index – measures average outage duration time for every customer served), SAIFI (System Average Interruption Frequency Index – measures average frequency of interruptions for every customer), and CAIDI (Customer Average Interruption Duration Index – measures average restoration time for every customer who lost power) among Pennsylvania electric utilities. As documented in the Company's 2024 Annual Reliability Report, Wellsboro achieved a SAIFI of .99 outages, a SAIDI of 102 minutes, and a CAIDI of 102 minutes. Exhibit __ (BF-2).

WELLSBORO STAFFING

Q. Please describe the relationship between C&T Enterprises and Wellsboro.

A. As Company witness Melissa Sullivan, Chief Financial Officer of C&T, explains in her Direct Testimony, C&T is a holding company, which owns 100% of Wellsboro's common stock. C&T also contracts with the other C&T affiliates to provide the staff necessary to meet their needs. Currently, C&T provides 9 employees to fulfill all of Wellsboro's staffing needs, with the exception of 8 union employees employed by Wellsboro. C&T also provides support services for activities that may not justify Wellsboro employing its own full or part-time employee, such as Human Resources, Information Technology support (e.g., network maintenance and administration), Safety Coordinator, Legal/Regulatory, Call Center and Communications activities. In addition to Wellsboro, C&T provides these same services to Citizens', Valley, Claverack Rural Electric Cooperative, and Tri-County Rural Electric Cooperative through a single set of C&T employees, who are considered "shared services" employees. Ms. Sullivan explains how the shared services costs are allocated.

Q. Do you anticipate any increases or decreases to the staffing at Wellsboro in the foreseeable future?

A. Wellsboro's Management team has been entrusted by the Board of Directors, shareholders, customers and the Commission to provide safe and reliable service at a fair cost. To address this core responsibility and the potentially negative impact from a failure to plan, we have a Succession plan for my role and I have each of my Department heads develop a Succession plan for their areas of responsibility that I report to our Board. One of our goals is preventing a lapse in experience and job knowledge necessary to effectively operate

Wellsboro's system. There are no retirements expected during 2025 or 2026. All of the office employees have Goals & Objectives developed annually which are reviewed periodically throughout the calendar year to ensure completion. My Goals & Objectives roll down through my direct reports and then to their direct reports to make sure yearly expectations are aligned from top to bottom in our organization. Within everyone's Goals & Objectives there is a Personal Development section that covers NISC training and other training to keep employee skills and knowledge growing each year. Along with the Personal Development we have ongoing cross training that is performed within departments and across departments based on Company needs, this provides us employees that can cover for vacations, unexpected absences and while other employees are out for training. There are no plans to change the staffing size in 2025 or 2026.

Q. Please discuss the Wage & Salary Study undertaken by Wellsboro and other C&T companies in 2024.

A. C&T undertook a Wage and Salary (W&S) study that was last performed 10-12 years prior. The need for a W&S study became evident during COVID as businesses moved critical employees to remote settings and needed to remain competitive to retain their employees. The W&S study started with each CEO evaluating their respective job descriptions and time for competency which were then used to compare similar positions across the various C&T companies with a goal for consistency. A third-party consultant was contracted to take our company positions and insert it into the market wage data they assembled from the market. The consultant data was reviewed by C&T personnel for reasonableness. In the end, Wellsboro found some employees that required increases which were planned to be

paid in one to two years depending on the magnitude of the increase. The first increase was performed on January 1, 2025 and the second increase will be performed on January 1, 2026. Going forward the consultant will provide updated market wage data annually that C&T will evaluate and update as appropriate. Wellsboro had some employees that were right where their wage needed to be, some required a modest increase and some were significantly below the market data for comparable positions. It is very important for Wellsboro to pay its employees appropriately for their jobs to ensure employees can be retained after investing in their training.

DERIVATION OF EXPENSES FOR FTY AND FPFTY

Q. Please explain how Wellsboro calculated the expenses for the HTY, FTY, and FPFTY that were provided to Mr. Gorman for his analysis.

A. Mr. Gorman's analysis uses calendar years in the statement of the HTY, FTY, and FPFTY expenses. This is consistent with Wellsboro's budgeting and financial reporting.

The HTY shows our actual 2024 expenses, with any appropriate ratemaking adjustments.

The FTY is based on the budget we approved for 2025, with any adjustments that we may have adopted since the Board of Directors approved the budget in late Fall 2024.

The FPFTY incorporates additional cost increases that we anticipate for 2026. These cost increases are based on our best judgment regarding wage, benefit and material costs inflation, which is approximately 3.0% each year on an overall aggregate basis.

Q. Please explain why a 3% inflation factor is appropriate for 2026.

A. As Ms. Campbell discusses, most of our expenses are labor and overhead. Ms. Sullivan's testimony discusses the historic and projected increases for non-union labor and benefits provided by C&T. Ms. Campbell discusses the projected increases for our union labor and

benefits. Combined, we view a 3% increase from 2025 to 2026 as a conservative projection.

Material and supply costs are impacted by both general economic inflation trends, tariffs and, at times, by product-specific developments. The most recent 12-month percentage change CPI published by the Bureau of Labor Statistics in March 2025, without food and energy, was just under 3%, while the total 12-month PPI in March 2025 was 3.4%. Many of our materials and supplies have components or materials that are sourced from non-domestic markets. The cost of those items will be impacted by President Trump's imposition of tariffs and other trade policies. Currently, it is uncertain how those costs will be impacted; however, we are anticipating that it will push the year over year prices higher than the normal rate of inflation (which we project at 3%). Given this uncertainty, we have not further increased the projections beyond the normal inflation measure (i.e., 3%).

PROPOSED TARIFF CHANGES

Q. What changes does Wellsboro propose to make to its Tariff as part of this filing?

A. Wellsboro proposes to make various changes to the rates in its Tariff. While I will discuss the general basis for certain proposals, Mr. Gorman's will more comprehensively review the specific rates and rate designs in his Direct Testimony.

Q. Please discuss the reasons supporting the Company's rate design proposals, including the increase in the Customer Charge for Rate Schedules RS – Residential, CS – Commercial Service, and IS – General Service.

A. As an EDC, almost all of Wellsboro's costs to provide service are fixed and do not shift with changing consumption. For example, the cost to produce a monthly bill for a customer

remains identical whether that customer uses 10 kWh of electricity per month or 5,000 kWh. Additionally, the cost to construct and maintain poles, wires, and services do not vary with usage. In our prior case, Wellsboro began adopting rate designs for each customer class that better reflect cost of service by collecting more costs through the flat monthly Customer Charge and moving away from declining rate block rates that rely so heavily on volumetric consumption. We propose to continue that progress in this proceeding. Mr. Gorman's testimony will provide greater detail regarding the specific changes the Company proposes to make in this proceeding to the rates in these customer classes.

Q. Please discuss the Company's proposed changes regarding Billing Demand, including the impact on customer-generators that are eligible for Net Metering under Rider D of Wellsboro's tariff.

A. Since our last rate case, the Pennsylvania courts invalidated the Commission's regulations that placed limitations on the size of a customer generator entitled to Net Metering under the Alternative Energy Portfolio Standards ("AEPS") Act. The Commission's regulations had required that the customer generator have independent load (e.g., usage for retail purposes) at the location where the generation is installed. In addition, the regulations placed size limitations on the capacity of the generation in relation to the independent load, in some configurations. In May 2020, the Pennsylvania Supreme Court invalidated

portions of the Commission's net metering regulations, including the "independent load" requirement.[1] /

As a result, EDCs like Wellsboro must accommodate the interconnection and net metering of customer generators with capacity of up to 3 MW that use very little electricity supplied by the EDC. In addition, we may have a customer that has generation producing power that exceeds their usage at the service location. In both scenarios, the customer generator uses the Wellsboro distribution system to deliver its output, which then offsets the energy that must be delivered to the Wellsboro service territory through the PJM (FE MAIT) transmission system. We are obligated to compensate the customer generator first by netting any electricity used by the account against the exported kWh, then by paying them "full retail value" for the remaining kWh at the end of the year that has not been netted against their usage. For customers with Billing Demands over 400 kW, the annual cash out will be a weighted average locational marginal price ("LMP").

Q. Has the Commission recently addressed the "full retail value" for the customer generators?

A. Yes. In a recent UGI Electric Division default service proceeding, the Commission clarified that the full retail value of the excess generation can be determined by an hourly generation price and that determinations for using a fixed or hourly generation price can

[1] *Hommrich v. Pennsylvania Public Utility Commission*, 231 A.3d 1027, 1036 (Pa. Cmwlth. 2020).

be made according to the size of the installed generation. In UGI's case, the threshold for applying the hourly price was 100 kW.

Q. Does the UGI decision extend to other rate placement determinations for customer generators?

A. I am advised by counsel that the logical legal extension of the UGI decision is that distribution service schedule placement and billing can reflect the customer generator's use of the distribution system, whether through its peak import from the system or its peak export to the distribution system. This ensures non-discriminatory treatment between customers that use the distribution system to power their non-residential operations and those who use the distribution system for the delivery of their energy product.

Q. What is Wellsboro proposing in this proceeding?

A. We are proposing to ensure that the customer generator's use of the distribution system and placement on our GSSR-1 or 2 appropriately reflects the use of the distribution system. Specifically, we are adding a definition of "Billing Demand" to our tariff, which states:

> **Billing Demand:** Billing Demand shall reflect the Customer's use of the distribution system, which will be the greater of Gross Generator Rating (kW(AC)) as stated in the generator interconnection application or the maximum demand of the customer during any 15-minute period during the current month.

We also propose to modify the "Billing KW" section in Service Schedules 4 and 5 to incorporate the "Billing Demand" definition above. The occurrences of the phrase "billing demand" in the GSSR-1 and GSSR-2 rate schedules, and in the "Generation and Transmission Charge" section of Service Schedules 4 and 5 will be changed to "Billing Demand" to incorporate the new definition. Finally, we will make minor changes in the

"Application of Schedule" sections in Service Schedules 3, 4 and 5 to clarify that the minimum or maximum demands listed will be determined based on Billing Demand (e.g., 7 kW maximum for Service Schedule No. 3; 7 kW minimum for Service Schedule No. 4; and 50 kW minimum for Service Schedule No. 5).

Q. Are Wellsboro's actions to design and maintain the distribution system different for a Service Schedule 5 customer that is using the distribution system to import 400 kW of electricity in comparison to a customer generator that is using the distribution system to export 400 kW of electricity to the system?

A. No. The design of the system and maintenance activities are very similar. We cannot plan segments of our system based on the theory that other local customers will have sufficient needs when the customer generator is exporting power to take that electricity. We have to engage in the same planning, maintenance, billing, customer service and other activities for both types of customers. It is fair for the customer generator to pay for their use of the distribution system. We have a System Study process that is required to be performed for any new interconnects that could adversely impact electric service for the other customers. The System Study is performed using the Peak (kW(AC)) value that is provided in the interconnection application. Using the Gross Generator Rating kW(AC) value in determining Billing Demand would be consistent with the evaluation performed during the System Study to maintain a stable system.

Q. Why is Wellsboro proposing to use the same definition of Billing Demand to determine the eligibility for the GSSR-1 or GSSR-2?

A. First, using the same definition will reduce customer confusion. Second, it ensures that the larger customer generators are categorized with similar customers (e.g., commercial

establishments). Without this change, their cash-out could be reflected in the GSSR-1 class, which is residential and small commercial customers. This would shift costs from their commercial activities and use of our system onto the residential class.

Q. Do you have any other changes to Wellsboro's tariff?

A. Yes. We have several sections that are no longer necessary and can be deleted.

First, because we have completed the conversion of the lighting on our system to LEDs, the old light fixture rates and the "conversion" language is no longer necessary and can be removed from Service Schedules 6 and 7.

Second, Rider B—Qualified Advanced Meters and Meter-related Devices can be removed. Our metering technology has greatly expanded and we accommodate this functionality with our utility meters.

Q. Does this conclude your Direct Testimony?

A. Yes.

BEFORE

THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	**:**	
	:	
v.	**:**	**Docket No. R-2025-_____**
	:	
Wellsboro Electric Company	**:**	

EXHIBITS

OF

BYRON FARNSWORTH, JR.

ON BEHALF OF

WELLSBORO ELECTRIC COMPANY

APRIL 30, 2025

WELLSBORO ELECTRIC COMPANY

QUARTERLY RELIABILITY REPORT
57.195 REPORTING REQUIREMENTS
Docket Number M-2023-3039027

Fourth Quarter 2024

October-December 2024

SUBMITTED BY

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57.195 Reporting Requirements Section (e) Item (5)

A rolling 12-month breakdown and analysis of outage causes during the receding quarter including the number and percentage of service outages, the number of customers interrupted, and customer interruption minutes catergorized by outage cause such as equipment failure, animal contact, tree related, and so forth. Proposed solutions to indentified service problems shall be reported.

Outage Cause	# Customers Affected	# of Outages	Customer Minutes	Percentage of Outages
Animal	494	49	30245	20.4%
Elec Overload	0	0	0	0.0%
Equipt Failure	229	24	24274	10.0%
Lightning	11	3	560	1.3%
Tree, Off, R.O.W.	4814	142	545416	59.2%
Tree, On R.O.W.	79	7	10787	2.9%
Unknown	805	15	45660	6.3%
Wind	0	0	0	0.0%
Total	**6432**	**240**	**656942**	**100%**

A description of each major event that occurred during the preceding quarter including the time and duration of the event, the number of customers affected, the cause of the event and any modified procedures adopted in order to avoid or minimize the impact of similar events in the future.

Date	Time of		Time	# Cust	Cause
October-December 2024	Event		Restored	Affected	
10/13/2024	12:54:00 PM	10/13/2024	14:59:00 PM	1078	Off ROW tree
10/14/2024	10:30:00 AM	10/14/2024	11:55:00 AM	735	Off ROW tree
11/28/2024	6:05:00 AM	11/28/2024	8:24:00 AM	1078	Wind

Cause	Apr-24	May-24	Jun-24	Jul-24	Aug-24	Sep-24	Oct-24	Nov-24	Dec-24	Jan-24	Feb-24	Mar-24	
NUMBER OF OUTAGES													
Animal	2	4	10	8	3	7	1	10	2	0	2	0	49
Elec Overload	0	0	0	0	0	0	0	0	0	0	0	0	0
Equipt Failure	5	2	2	2	2	1	4	1	0	5	0	0	24
Lightning	1	0	0	0	0	2	0	0	0	0	0	0	3
Tree, Off, R.O.W	5	16	19	13	13	5	5	27	16	13	1	9	142
Tree, On R.O.W.	0	0	2	2	2	0	0	0	1	0	0	0	7
Unknown	0	1	3	5	1	1	0	0	2	1	0	1	15
Wind	0	0	0	0	0	0	0	0	0	0	0	0	0
	13	23	36	30	21	16	10	38	21	19	3	10	240

Cause	Apr-24	May-24	Jun-24	Jul-24	Aug-24	Sep-24	Oct-24	Nov-24	Dec-24	Jan-24	Feb-24	Mar-24	
CUSTOMERS AFFECTED													
Animal	3	32	45	168	5	179	1	31	28	0	2	0	494
Elec Overload	0	0	0	0	0	0	0	0	0	0	0	0	0
Equipt Failure	28	2	24	39	14	1	32	65	0	24	0	0	229
Lightning	1	0	0	0	0	10	0	0	0	0	0	0	11
Tree, Off, R.O.W.	623	951	798	756	359	31	53	334	414	241	1	253	4814
Tree, On R.O.W.	0	0	12	19	43	0	0	0	5	0	0	0	79
Unknown	0	1	89	633	1	13	0	0	5	1	0	62	805
Wind	0	0	0	0	0	0	0	0	0	0	0	0	0
	655	986	968	1615	422	234	86	430	452	266	3	315	6432

Cause	Apr-24	May-24	Jun-24	Jul-24	Aug-24	Sep-24	Oct-24	Nov-24	Dec-24	Jan-24	Feb-24	Mar-24	
Customer Minutes													
Animal	211	2232	2909	10481	244	12046	56	727	1258	0	81	0	30245
Elec Overload	0	0	0	0	0	0	0	0	0	0	0	0	0
Equipt Failure	2059	174	2330	2350	1261	53	2390	11929	0	1729	0	0	24274
Lightning	21	0	0	0	0	539	0	0	0	0	0	0	560
Tree, Off, R.O.W.	57008	66174	107618	116516	27470	2994	2885	46871	61947	29252	280	26401	545416
Tree, On R.O.W.	0	0	1035	1637	6500	0	0	0	1614	0	0	0	10787
Unknown	0	28	6208	32989	55	1220	0	0	418	83	0	4657	45660
Wind	0	0	0	0	0	0	0	0	0	0	0	0	0
	59299	68608	120100	163974	35530	16852	5332	59527	65237	31064	361	31058	656942

Rolling 12-Month reliability index values (SAIFI,CAIDI,SAIDI) for the EDC'S service territory for the receding quarter. The report shall include the data used in calculating the indices, namely the average number of customers served, the number of sustained customers interruptions, the number of customers affected, and the customer minutes of interruption.

WELLSBORO ELECTRIC COMPANY

ROLLING TWELVE MONTH INTERRUPTION INDEXS

4th Quarter 2024

SAIDI	SAIFI	CAIDI
102	0.99	102

ROLLING TWELVE MONTH STANDARD AS ESTABLISHED BY THE PUC

SAIDI	SAIFI	CAIDI
278	1.66	167

ROLLING THREE YEAR AVERAGE INTERRUPTION INDEXS

SAIDI	SAIFI	CAIDI
133	1.15	115

ROLLING THREE YEAR AVERAGE STANDARD AS ESTABLISHED BY THE PUC

SAIDI	SAIFI	CAIDI
185	1.12	136

AVERAGE NUMBER OF CUSTOMERS SERVED

6472

Wellsboro Electric Company **Reliability Index** **SAIDI**

Month	Total Customer Minutes	# Customers Served
Jan-24	31064.4	6464
Feb-24	361.2	6463
Mar-24	31057.8	6464
Apr-24	59298.6	6466
May-24	68608.2	6469
Jun-24	120100.2	6471
July-24	163974.6	6474
Aug-24	35530.2	6476
Sept-24	16851.6	6477
Oct-24	5331.6	6478
Nov-24	59526.6	6479
Dec-24	65237.4	6479
Totals	**656942.4**	**77660**

Average # Customers Served	**6472**
ROLLING TWELVE MONTH AVERAGE SAIDI INDEX	**101.51**

Wellsboro Electric Company **Reliability Index** **SAIFI**

Month	# Customers Interrupted	# Customers Served
Jan-24	266	6464
Feb-24	3	6463
Mar-24	315	6464
Apr-24	655	6466
May-24	986	6469
Jun-24	968	6471
July-24	1615	6474
Aug-24	422	6476
Sept-24	234	6477
Oct-24	86	6478
Nov-24	430	6479
Dec-24	452	6479
Totals	**6432**	**77660**

Average # Customers Served **6472**

Rolling Twelve Month Average SAIFI Index **0.99**

57.195 Reporting Requirements | Section(e) Item (2)

Wellsboro Electric Company | **Reliability Index** | **CAIDI**

Month	Total Customer Minutes	# Customers Interrupted
Jan-24	31064.4	266
Feb-24	361.2	3
Mar-24	31057.8	315
Apr-24	59298.6	655
May-24	68608.2	986
Jun-24	120100.2	968
July-24	163974.6	1615
Aug-24	35530.2	422
Sept-24	16851.6	234
Oct-24	5331.6	86
Nov-24	59526.6	430
Dec-24	65237.4	452
Totals	**656942.4**	**6432**

Rolling Twelve Month Average CAIDI Index **102.14**

ROLLING THREE YEAR WORKSHEET **4th Quarter 2024**

QTR	SAIDI	SAIFI	CAIDI
4-22	33.00	0.27	122.00
3-22	24.00	0.26	91.00
2-22	58.00	0.36	162.00
1-22	27.00	0.20	137.00
4-24	20.00	0.15	134.00
3-24	33.00	0.35	95.00
2-24	38.00	0.40	95.00
1-24	10.00	0.09	107.00
4-23	30.00	0.26	118.00
3-23	83.00	0.68	122.00
2-23	24.00	0.27	91.00
1-23	18.00	0.17	108.00
	398	3.46	1382
	132.6667	1.153333	115.1667

Summary

Trees caused (62.1%) of the outages (2.9% ON-ROW and 59.2% OFF-ROW)

Animal contacts caused (20.4%) of the outages

Equipment failures (10.0%) these outages were associated with cutouts, arrestors, and jumpers.

Unknown (6.3%)

Lightning (1.3%)

The Company filed exemptions for 3 major events in the 4th quarter of 2024.

WELLSBORO ELECTRIC COMPANY
Est 1894
P. O. Box 138 • 33 Austin Street • Wellsboro, PA 16901
(570) 724-3516 • FAX (570) 724-1798

April 15, 2025

E-FILED

Mr Matthew Homsher, Secretary
Pennsylvania Public Utility Commission
Commonwealth Keystone Building
2nd Floor, Room-N201
400 North Street
Harrisburg, PA 17120

Re: **Wellsboro Electric Company 2024 Annual Electric Reliability Report Docket No. M-2023-3039027**

Dear Secretary Homsher:

Please find enclosed for filing Wellsboro Electric Company's 2024 Annual Electric Reliability.

If you have any questions regarding the information contained in this filing, please contact me at (570)724-6701 or barneyf@ctenterprises.org.

Sincerely,

Byron Farnsworth Jr.
President/CEO

Enclosure
c (w/ enc.):
Bureau of Technical Utility Services (jvanzant@pa.gov, dsearfoorc@pa.gov,)
Office of Consumer Advocate (kyetter@paoca.org)
Office of Small Business Advocate (tereswagne@pa.gov)

2024 Annual Electric Reliability Report

to the

Pennsylvania Public Utility Commission

Wellsboro Electric Company
33 Austin Street
Wellsboro, PA 16901

April 15, 2025

WELLSBORO ELECTRIC COMPANY
ANNUAL ELECTRIC RELIABILITY REPORT

Filed April 15, 2025

52 Pa Code §57.195 Reporting Requirements

(a)(2) The name, title, telephone number and e-mail address of the persons who have knowledge of the matters, and can respond to inquiries.

Byron Farnsworth Jr. – President/CEO
(570)724-6701, barneyf@ctenterprises.org

Tyler Mead – Director of Engineering & Operations
(570)724-6725, tylerm@ctenterprises.org

(b)(1) An overall current assessment of the state of the system reliability in the electric distribution company's service territory including a discussion of the electric distribution company's current programs and procedures for providing reliable electric service.

Wellsboro Electric Company has maintained excellent reliability indices during 2024 keeping all of our indices below the PUC established standard. The Company experienced 10 major events throughout 2024 including rain, wind, and heavy snow events that impacted reliability. By maintaining a small number of major events, the Company recognizes this will increase some of our indices because the outages will be much smaller and be pushed out to the extremities of our system, which will not allow them to qualify as a major event. The Company will continue trimming 70-75 miles per year, which amounts to a circuit or a portion of a circuit each year and keeps us around a 5-year cycle. The Company identified hot spot trimming on the downtown three phase portion of the system. Danger trees were identified In and Out of ROW during the year and urgent removals were dealt with immediately and other Danger trees are prioritized and removed as funding is available.

In 2024, the Company reconductored 7 miles of line, and installed other group operated switches to create tie points in the system. In 2025, the Company plans to reconductor another 3 miles of line and work to build another tie point. This will provide reliability to the circuits allowing an alternate feed.

The Company continues to participate in and gather information from various industry best practice groups. These groups include members from diverse utility groups such as the Pennsylvania Rural Electric Association, the Energy Association of Pennsylvania, and the National Rural Electric Cooperative Association. The Company will continue to implement best practices defined by these groups as appropriate.

The Company does not own or maintain any transmission facilities.

Current Maintenance Programs

Program	Description	Cycle
Infrared Inspection	All substation equipment monthly, and overhead lines as needed.	Monthly
Vegetation Management	Each year, primary lines are visually inspected on 4 circuits. This comprehensive field inspection allows us to identify areas that require trimming. We are striving to maintain a 5–6 year trimming cycle and the Boro is inspected annually to help identify unexpected "hot spots." Based on a bid the winning bidder. Trimmed 70 miles by the end of 2024.	2 Years – Visual 5-6 Years – Trimming
Visual Line Inspection	4 distribution circuits lines and pole hardware are visually inspected each year during preparation of tree trimming contract. Line sections receiving infrared inspection are also inspected visually during that process. Drones are used on a limited basis in tough to access ROWs to inspect structures, equipment and tree conditions. AppSuite is being used to capture specific information which is then transferred into our IVUE system to run reports.	2 Years
Overhead Transformer Inspection	Overhead equipment on 4 circuits are visually inspected each year to identify and correct any developing problems or safety concerns.	2 Years
Padmount Transformer Inspection	Padmounted equipment on 2 circuits are visually inspected each year to identify and correct any developing problems or safety concerns.	4 Years
Line Equipment Inspection	Air switches, circuit tie switches, capacitors, regulators, and reclosers are visually inspected during the Line Inspections each year. Where applicable, proper operation of control equipment is verified, and counter readings are recorded.	Annual
Pole Inspection	Poles are inspected at the ground line with a sonic and bore style test.	10 Years
Reject Pole Replacements	Replace condemned poles identified during pole inspection.	As needed, annually
Substation Equipment Inspection	Entire station is visually inspected. Equipment batteries are tested, communications equipment operation is verified, fans are tested, various gauge and counter readings are recorded. An infrared inspection is performed on all equipment monthly.	Monthly
Regulator/OCR Maintenance	Tripsaver reclosers will be inspected during the Line Inspections each year. Regulators are visually inspected monthly	Monthly - Regulators Annually – OCR's

(b)(2) A description of each major event that occurred during the year being reported on, including the time and duration of the event, the number of customers affected, the cause of the event and any modified procedures adopted in order to avoid or minimize the impact of similar events in the future.

Date	Time	Duration of Event (Minutes)	#of Customers Affected	Cause
1/9/2024	12:46 PM	2,129,900	5382	High wind
2/28/2024	14:51 PM	185,742	2193	High wind
5/2/2024	01:19 AM	173,370	1735	Animal Contact
6/12/2024	10:34 AM	40,984	1738	Equipment Failure
6/17/2024	18:38 PM	199,183	1388	Animal Contact
6/20/2024	12:19 PM	42,000	1738	Unknown
7/15/2024	17:15 PM	1,223,750	1837	High Wind
10/13/2024	12:54 PM	98,653	1078	High Wind/Off ROW Tree
10/14/2024	10:30 AM	62,340	735	High Wind/Off ROW Tree
11/28/2024	06:05 AM	150,057	1078	

(b)(3) A table showing the actual values of each of the reliability indices (SAIFI, CAIDI, SAIDI, and if available, MAIFI) for the electric distribution company's service territory for each of the preceding 3 calendar years. The report shall include the data used in calculating the indices, namely the average number of customers served, the number of sustained customer minutes interruptions, the number of customers affected, and the minutes of interruption. If MAIFI values are provided, the number of customer momentary interruptions shall also be reported.

RELIABILITY BENCHMARKS AND STANDARDS
Wellsboro Electric Company**

	SAIDI	SAIFI	CAIDI	MAIFI
2024	102	.99	102	*
2023	155	1.37	114	*
2022	142	1.09	130	*
3 Year Average	133	1.15	116	*

* Sufficient information to calculate MAIFI is unavailable.
** System Performance Measures with Major Events and Planned Outages Excluded

Formulas Used in Calculating the Indices

SAIFI = Number of Customers experiencing an Interruption / Average Customers served

SAIDI = (Total Cust.-minutes interrupted) - (Cust.-minutes for a major event) / Average Customers served

CAIDI = SAIDI/SAIFI

(b)(4) A breakdown and analysis of outage causes during the year being reported on, including the number and percentage of service outages and customer interruption minutes categorized by outage cause such as equipment failure, animal contact, tree related, and so forth. Proposed solutions to identified service problems shall be reported.

January 1, 2024 through December 31, 2024

Outage Cause	Number of Interruptions	% of Interruptions	Number of Customers Affected	Customer Interruption Minutes
Animal	49	20.4%	494	30,245
Equipt Failure	24	10.0%	229	24,274
Tree, On, R.O.W.	7	2.9%	79	10,787
Tree, Off R.O.W.	142	59.2%	4814	545,416
Unknown	15	6.3%	805	45,660
Lightning	3	1.3%	11	560
Total	**240**	**100.0%**	**6432**	**656,942**

January 1, 2023 through December 31, 2023

Outage Cause	Number of Interruptions	% of Interruptions	Number of Customers Affected	Customer Interruption Minutes
Animal	31	14.8%	502	27,196
Equipt Failure	23	11.0%	640	49,926
Tree, On, R.O.W.	3	1.4%	31	2,334
Tree, Off R.O.W.	126	60.3%	6611	834,774
Unknown	25	12.0%	1036	88,180
Lightning	1	0.5%	2	608
Total	**209**	**100.0%**	**8822**	**1,003,019**

January 1, 2022 through December 31, 2022

Outage Cause	Number of Interruptions	% of Interruptions	Number of Customers Affected	Customer Interruption Minutes
Animal	57	24.9%	1277	180,514
Equipt Failure	35	15.3%	1351	255,308
Tree, On, R.O.W.	5	2.2%	64	10,310
Tree, Off R.O.W.	89	38.9%	3315	386,547
Unknown	35	15.3%	974	79,415
Lightning	8	3.5%	43	3,281
Total	**229**	**100.0%**	**7024**	**915,376**

Wellsboro Electric Co. Customer Service
Utility Code 111200
2022 Survey Results

Please choose one of the following ratings for each question that appears below:

1 Very Satisfied
2 Somewhat Satisfied
3 Neither Satisfied nor Dissatisfied
4 Somewhat Dissatisfied
5 Very Dissatisfied
6 Don't Know
7 Did not Call or Visit Office

1. How satisfied were you with the ease of contacting Wellsboro Electric Company?

1	2	3	4	5	6	7
44	5	4	0	1	0	21

2. How courteous was the customer service representative with whom you spoke?

1	2	3	4	5	6
51	2	0	1	0	0

3. How knowledgeable was the customer service representative with whom you spoke?

1	2	3	4	5	6
50	3	1	0	0	0

4. How satisfied were you with the way in which the customer service representative handled your question?

1	2	3	4	5	6
49	3	0	2	0	0

5. As a result of your contact with Wellsboro Electric Company, did anyone from our company make a visit to your home or property? Yes - 9

6. Were the visit and/or required work completed in a timely manner?

1	2	3	4	5	6
8	0	0	0	0	1

7. How courteous was the field representative who visited your home or property?

1	2	3	4	5	6
6	0	0	0	0	3

8. How knowledgeable was the field representative who visited your home or property?

1	2	3	4	5	6
5	0	2	0	0	2

9. How satisfied were you with how the field representative handled the visit to your home or property?

1	2	3	4	5	6
4	2	0	0	0	3

10. Considering all aspects of this recent contact with Wellsboro Electric Company, how satisfied were you with the quality of service provided by Wellsboro Electric Company.

1	2	3	4	5	6
47	6	0	0	1	0

11. If you indicated that you were somewhat dissatisfied or very dissatisfied with your interaction with Wellsboro Electric Company, would you like someone from our office to contact you about this?

Yes – 4

Wellsboro Electric Co. Customer Service
Utility Code 111200
2023 Survey Results

Please choose one of the following ratings for each question that appears below:

1 Very Satisfied
2 Somewhat Satisfied
3 Neither Satisfied nor Dissatisfied
4 Somewhat Dissatisfied
5 Very Dissatisfied
6 Don't Know
7 Did not Call or Visit Office

1. How satisfied were you with the ease of contacting Wellsboro Electric Company?

1	2	3	4	5	6	7
91	10	1	1	0	0	53

2. How courteous was the customer service representative with whom you spoke?

1	2	3	4	5	6
95	6	0	1	0	0

3. How knowledgeable was the customer service representative with whom you spoke?

1	2	3	4	5	6
93	8	0	1	0	0

4. How satisfied were you with the way in which the customer service representative handled your question?

1	2	3	4	5	6
92	6	0	1	0	0

5. As a result of your contact with Wellsboro Electric Company, did anyone from our company make a visit to your home or property? Yes - 18

6. Were the visit and/or required work completed in a timely manner?

1	2	3	4	5	6
18	0	0	0	0	0

7. How courteous was the field representative who visited your home or property?

1	2	3	4	5	6
17	0	0	0	0	1

8. How knowledgeable was the field representative who visited your home or property?

1	2	3	4	5	6
18	0	2	0	0	0

9. How satisfied were you with how the field representative handled the visit to your home or property?

1	2	3	4	5	6
17	0	0	0	0	1

10. Considering all aspects of this recent contact with Wellsboro Electric Company, how satisfied were you with the quality of service provided by Wellsboro Electric Company.

1	2	3	4	5	6
95	4	2	1	0	0

11. If you indicated that you were somewhat dissatisfied or very dissatisfied with your interaction with Wellsboro Electric Company, would you like someone from our office to contact you about this?

Yes – None

Wellsboro Electric Co. Customer Service
Utility Code 111200
2024 Survey Results

Please choose one of the following ratings for each question that appears below:

1. Very Satisfied
2. Somewhat Satisfied
3. Neither Satisfied nor Dissatisfied
4. Somewhat Dissatisfied
5. Very Dissatisfied
6. Don't Know
7. Did not Call or Visit Office

1. How satisfied were you with the ease of contacting Wellsboro Electric Company?

1	2	3	4	5	6	7
73	8	1	0	1	0	49

2. How courteous was the customer service representative with whom you spoke?

1	2	3	4	5	6
79	5	0	0	2	0

3. How knowledgeable was the customer service representative with whom you spoke?

1	2	3	4	5	6
75	6	3	0	2	0

4. How satisfied were you with the way in which the customer service representative handled your question?

1	2	3	4	5	6
74	5	3	1	2	0

5. As a result of your contact with Wellsboro Electric Company, did anyone from our company make a visit to your home or property? Yes - 16

6. Were the visit and/or required work completed in a timely manner?

1	2	3	4	5	6
16	0	0	0	0	0

7. How courteous was the field representative who visited your home or property?

1	2	3	4	5	6
15	1	0	0	0	0

8. How knowledgeable was the field representative who visited your home or property?

1	2	3	4	5	6
16	0	0	0	0	0

9. How satisfied were you with how the field representative handled the visit to your home or property?

1	2	3	4	5	6
16	0	0	0	0	0

10. Considering all aspects of this recent contact with Wellsboro Electric Company, how satisfied were you with the quality of service provided by Wellsboro Electric Company.

1	2	3	4	5	6
69	7	0	2	1	0

11. If you indicated that you were somewhat dissatisfied or very dissatisfied with your interaction with Wellsboro Electric Company, would you like someone from our office to contact you about this?

Yes – 2

Wellsboro Electric Company
PUC Quality of Service
Exhibit BF-4

2022	January	96.2%
2022	February	89.4%
2022	March	85.7%
2022	April	89.8%
2022	May	95.6%
2022	June	98.0%
2022	July	98.2%
2022	August	98.2%
2022	September	98.8%
2022	October	98.8%
2022	November	99.5%
2022	December	93.0%
12-mth Average		**95.08%**

2023	January	98.4%
2023	February	97.8%
2023	March	99.0%
2023	April	99.5%
2023	May	98.7%
2023	June	98.7%
2023	July	98.3%
2023	August	97.1%
2023	September	97.7%
2023	October	98.1%
2023	November	97.7%
2023	December	96.8%
12-mth Average		**98.15%**

2024	January	95.6%
2024	February	97.1%
2024	March	97.2%
2024	April	97.1%
2024	May	97.6%
2024	June	97.7%
2024	July	95.6%
2024	August	95.4%
2024	September	100.0%
2024	October	97.4%
2024	November	94.4%
2024	December	97.4%
12-mth Average		**96.87%**

Wellsboro Electric Company **Exhibit_(BF-5) Capital Budgets**

2024 Capital Budget - Engineering & Operations

GL Code	Description	2024 Budget	Actual Cost 1/31/2024	Actual Cost 2/28/2024	Actual Cost 3/31/2024	Actual Cost 4/30/2024	Actual Cost 5/31/2024	Actual Cost 6/30/2024	Actual Cost 7/31/2024	Actual Cost 8/31/2024	Actual Cost 9/30/2024	Actual Cost 10/31/2024	Actual Cost 11/30/2024	Actual Cost 12/31/2024	Actual Cost YTD
100	New Services	**30,000**	-	-	-	-	3,687.62	15,813.82	35,291.01	11,095.55	13,598.48	37,078.48	-	-	116,564.96
101	New Underground Service	**40,000**	5,371.30	-	-	11,736.71	-	-	-	10,960.38	11,274.50	4,120.36	6,246.90	3,708.79	53,418.94
102	New Overhead Service	**16,000**	705.29	1,061.08	1,144.92	2,188.31	79,633.10	-	3,356.24	765.44	858.21	867.53	5,054.98	-	95,635.10
103	New Service Upgrade w/Rtd	**45,000**	-	-	-	963.75	-	-	3,770.82	3,155.07	-	7,479.16	-	-	15,368.80
104	New OH Service w/Retirements	**10,000**	-	-	-	-	-	-	-	-	-	-	-	837,416.08	837,416.08
105	New OH and UG Service w/Retirements	**-**	-	-	-	-	841,048.21	-	-	-	-	-	-	-	841,048.21
113	Capital Improvement Projects	**785,000**	-	-	-	-	21,153.13	13,240.83	3,226.86	-	-	23,537.19	43,260.79	886,525.12	990,943.92
300	Misc System Improvements	**15,000**	58,865.39	5,635.58	10,734.03	14,236.77	18,347.08	24,927.76	13,106.94	10,694.19	5,361.43	3,271.28	13,820.02	14,574.26	193,574.73
301	Pole for Additional Height	**10,000**	-	-	-	-	-	-	-	-	-	10,094.65	-	-	10,094.65
302	Customer request line change	**-**	-	-	-	-	-	-	-	-	-	-	-	-	-
303	Ordinary Replacement	**-**	-	-	-	-	-	-	-	-	-	-	-	-	-
305	Storm Damage	**20,000**	-	8,480.02	-	-	-	-	82,338.93	-	-	29,184.00	-	-	120,002.95
400	Motor Vehicle Accidents	**-**	-	-	-	-	-	1,104.69	-	-	3,999.86	287.72	-	-	5,392.27
600	Special Equipment	**31,000**	-	-	-	-	-	-	-	-	-	-	-	-	-
601	Transformer-replacement/Upgrade	**8,500**	-	-	-	-	-	-	-	-	-	-	-	-	-
602	Transformer's-Cost	**150,000**	-	-	-	4,060.00	77,835.00	38,935.00	-	-	-	-	-	-	120,830.00
603	Cutouts/Sectionilizing	**-**	-	-	-	-	-	-	-	-	-	-	-	-	-
604	Regulator's	**140,000**	-	-	-	91,078.80	45,389.40	-	-	-	-	-	-	-	136,468.20
605	Capacitor's	**-**	-	-	-	-	-	-	-	-	-	-	-	-	-
606	Anchor's & Guy Replacement	**2,000**	44,693.09	-	-	-	-	-	-	-	-	-	-	-	44,693.09
607	Pole Replacement's	**500,000**	-	114,980.18	73,798.76	102,731.21	4,301.96	61,042.69	62,964.95	58,152.36	58,498.31	9,452.22	2,367.35	11,766.64	560,056.63
608	Reliability Improvement's	**50,000**	5,287.17	-	-	296.22	-	-	-	3,285.73	-	-	-	6,977.65	15,846.77
609	Install Ground's	**-**	-	-	-	-	-	-	-	-	-	-	-	-	-
610	Oil Circuit Reclosurer's-OCR's	**-**	-	-	-	-	-	-	-	-	-	-	-	-	-
700	Street Light's	**2,500**	-	506.20	-	-	-	-	-	-	641.58	-	-	68.15	1,215.93
701	Customer Outdoor Light's	**2,500**	743.21	1,142.15	421.80	-	444.42	53.66	-	3,349.22	-	414.16	-	-	6,568.62
702	Make Ready Work	**-**	-	-	-	-	-	-	-	-	-	8,660.63	-	-	8,660.63
703	Solar Make Ready Work	**-**	-	563.76	-	-	-	-	-	-	-	-	-	-	563.76
000	Retirement	**5,000**	-	-	-	-	-	-	138.87	-	-	-	-	34,598.22	34,737.09
	Construction Total	**1,862,500**	115,665.45	132,368.97	86,099.51	227,291.77	1,091,839.92	155,118.45	204,194.62	101,457.94	94,232.37	134,447.38	70,750.04	1,795,634.91	4,209,101.33
	Misc														
#362.00	Substation	**-**	-	-	-	-	-	-	-	-	-	-	-	-	-
#370.00	Meters	**20,000**	-	-	-	-	-	-	-	-	1,300.00	17,040.00	-	1,720.00	20,060.00
#390.00	Office - Structure & Improvements	**-**	-	-	-	-	-	-	-	-	-	-	-	3,721,728.13	3,721,728.13
#391.00	Office - Furniture & Equipment/IT	**124,680**	10,441.00	-	-	1,883.62	-	-	-	-	17,161.40	275.60	1,504.14	262,035.56	293,301.32
#394.00	Tools & Shop Equipment	**10,000**	-	-	-	-	-	-	-	-	-	-	-	-	-
#395.00	Equipment - outside	**-**	-	-	-	-	-	-	-	-	-	-	-	-	-
#396.00	Equipment - Power Operated	**-**	-	-	-	-	-	-	-	-	-	-	-	72,184.49	72,184.49
#397.00	Communication Equipment	**-**	-	-	-	1,302.48	-	-	2,647.50	-	-	-	-	3,624.80	7,574.78
	Misc Total	**154,680**	10,441.00	-	-	3,186.10	-	-	2,647.50	-	18,461.40	17,315.60	1,504.14	4,061,292.98	4,114,848.72
	Company Total	**2,017,180**	126,106.45	132,368.97	86,099.51	230,477.87	1,091,839.92	155,118.45	206,842.12	101,457.94	112,693.77	151,762.98	72,254.18	5,856,927.89	8,323,950.05
#392.00	Transportation Equipment	**325,000**	-	-	-	-	-	-	-	66,390.00	-	-	-	-	66,390.00

Wellsboro Electric Company **Exhibit_(BF-5) Capital Budgets**

2023 Capital Budget - Engineering & Operations

GL Code	Description	2023 Budget	Actual Cost 1/31/2023	Actual Cost 2/28/2023	Actual Cost 3/31/2023	Actual Cost 4/30/2023	Actual Cost 5/31/2023	Actual Cost 6/30/2023	Actual Cost 7/31/2023	Actual Cost 8/31/2023	Actual Cost 9/30/2023	Actual Cost 10/31/2023	Actual Cost 11/30/2023	Actual Cost 12/31/2023	Actual Cost YTD
100	New Services	**30,000**	-	11,103.19	4,760.15	15,642.64	5,044.17	-	24,223.16	6,013.81	15,498.31	10,976.03	-	47,698.63	140,960.09
101	New Underground Service	**40,000**	16,603.83	-	-	2,617.78	10,354.95	5,158.65	3,029.20	5,742.31	-	13,347.55	11,077.34	-	67,931.61
102	New Overhead Service	**16,000**	-	-	-	19,025.20	-	-	-	12,681.35	-	3,081.31	1,785.12	7,178.92	43,751.90
103	New Service Upgrade w/Rtd	**45,000**	-	-	-	16,947.90	6,636.24	-	-	-	-	-	-	-	23,584.14
104	New OH Service w/Retirements	**10,000**	-	-	-	-	-	-	-	-	-	-	-	-	-
105	New OH and UG Service w/Retirements	**-**	-	-	-	-	-	-	-	-	-	-	-	-	-
113	Capital Improvement Projects	**655,000**	-	-	-	-	4,195.47	16,338.15	3,527.58	546,586.01	282,676.48	22,302.90	57,100.69	2,553,830.96	3,486,558.24
300	Misc System Improvements	**15,000**	11,623.92	8,218.32	15,123.78	14,705.28	6,383.73	5,689.77	11,626.98	7,327.06	27,080.01	7,387.43	17,652.48	14,056.05	146,874.81
301	Pole for Additional Height	**10,000**	-	-	-	2,755.10	-	-	-	-	-	47,295.57	-	-	50,050.67
302	Customer request line change	**-**	-	-	-	-	-	-	-	-	-	-	-	-	-
303	Ordinary Replacement	**-**	-	-	-	-	-	-	-	-	-	-	-	-	-
305	Storm Damage	**20,000**	-	-	-	3,328.30	-	-	-	-	5,371.74	-	-	-	8,700.04
400	Motor Vehicle Accidents	**-**	-	-	7,152.58	-	-	2,866.12	-	-	-	2,298.86	-	3,603.33	15,920.89
600	Special Equipment	**31,000**	-	14,491.00	-	-	-	-	-	70,353.54	-	-	-	-	84,844.54
601	Transformer-replacement/Upgrade	**8,500**	-	-	-	-	-	-	-	-	-	-	-	-	-
602	Transformer's-Cost	**150,000**	-	47,260.00	70,468.00	-	-	-	11,130.00	96,772.00	11,130.00	-	-	-	236,760.00
603	Cutouts/Sectionilizing	**-**	-	-	-	-	-	23,158.08	-	-	-	-	-	-	23,158.08
604	Regulator's	**80,000**	-	-	-	-	-	-	-	-	-	-	-	-	-
605	Capacitor's	**-**	-	-	-	-	-	-	-	-	-	-	-	-	-
606	Anchor's & Guy Replacement	**2,000**	-	-	-	-	-	-	-	-	-	-	-	-	-
607	Pole Replacement's	**600,000**	2,121.86	121,662.67	44,524.20	63,638.54	97,793.20	90,931.69	55,516.48	65,601.16	28,756.04	88,537.09	-	63,665.61	722,748.54
608	Reliability Improvement's	**50,000**	12,569.39	-	-	29,278.16	-	-	-	15,514.64	-	-	-	3,774.29	61,136.48
609	Install Ground's	**-**	-	-	-	-	-	-	-	-	-	-	-	-	-
610	Oil Circuit Reclosurer's-OCR's	**-**	-	-	-	-	-	-	-	-	-	-	-	-	-
700	Street Light's	**57,000**	-	-	-	-	-	722.38	-	-	-	-	-	-	722.38
701	Customer Outdoor Light's	**42,000**	5,518.12	1,802.36	5,910.31	1,419.14	3,067.75	30,120.84	15,394.61	16,316.76	19,661.29	16,603.30	8,951.13	-	124,765.61
702	Make Ready Work	**-**	-	-	-	-	-	-	-	-	-	-	-	-	-
703	Solar Make Ready Work	**-**	-	-	-	-	-	-	-	-	-	-	-	-	-
000	Retirement	**5,000**	-	-	-	104.05	-	-	-	-	-	-	-	-	104.05
	Construction Total	**1,866,500**	48,437.12	204,537.54	147,939.02	169,462.09	133,475.51	174,985.68	124,448.01	842,908.64	390,173.87	211,830.04	96,566.76	2,693,807.79	5,238,572.07
	Misc														
#362.00	Substation	**-**	-	-	-	-	-	-	-	-	-	2,756.00	-	-	2,756.00
#370.00	Meters	**8,000**	-	-	-	-	-	-	-	-	-	1,300.00	-	-	1,300.00
#390.00	Office - Structure & Improvements	**-**	-	-	42,825.00	-	-	-	-	-	-	-	-	-	42,825.00
#391.00	Office - Furniture & Equipment/IT	**160,200**	-	50.00	3,990.00	17,569.50	-	2,146.50	-	-	-	7,963.20	403.83	-	32,123.03
#394.00	Tools & Shop Equipment	**10,000**	-	-	-	-	-	-	-	-	-	-	-	-	-
#395.00	Equipment - outside	**-**	-	-	-	-	-	-	-	-	-	-	-	-	-
#396.00	Equipment - Power Operated	**-**	-	17,630.25	-	-	-	-	-	-	-	-	-	-	17,630.25
#397.00	Communication Equipment	**-**	12,899.44	26,631.78	-	-	-	6,284.30	9,116.00	-	-	-	1,350.00	-	56,281.52
	Misc Total	**178,200**	12,899.44	44,312.03	46,815.00	17,569.50	-	8,430.80	9,116.00	-	-	12,019.20	1,753.83	-	152,915.80
	Company Total	**2,044,700**	61,336.56	248,849.57	194,754.02	187,031.59	133,475.51	183,416.48	133,564.01	842,908.64	390,173.87	223,849.24	98,320.59	2,693,807.79	5,391,487.87
#392.00	Transportation Equipment	**215,000**	-	-	-	-	-	-	-	-	-	24,262.12	185,574.20	-	209,836.32

Wellsboro Electric Company **Exhibit_(BF-5) Capital Budgets**

2022 Capital Budget - Engineering & Operations

GL Code	Description	2022 Budget	Actual Cost 1/31/2022	Actual Cost 2/28/2022	Actual Cost 3/31/2022	Actual Cost 4/30/2022	Actual Cost 5/31/2022	Actual Cost 6/30/2022	Actual Cost 7/31/2022	Actual Cost 8/31/2022	Actual Cost 9/30/2022	Actual Cost 10/31/2022	Actual Cost 11/30/2022	Actual Cost 12/31/2022	Actual Cost YTD
100	New Services	**30,000**	-	-	15,347.28	-	-	-	-	18,888.00	8,578.15	4,769.10	-	11,832.55	59,415.08
101	New Underground Service	**35,000**	-	4,445.53	-	-	6,882.89	11,589.37	-	3,798.21	5,792.64	60,770.48	-	15,145.58	108,424.70
102	New Overhead Service	**15,000**	-	1,144.81	-	-	2,069.29	19,663.06	857.09	8,519.78	-	158.34	-	755,046.33	787,458.70
103	New Service Upgrade w/Rtd	**40,000**	-	-	-	927.06	-	-	5,548.68	-	5,836.08	13,473.41	-	-	25,785.23
104	New OH Service w/Retirements	**10,000**	-	2,674.40	-	-	-	-	-	4,860.27	6,855.26	3,854.15	-	1,234.57	19,478.65
105	New OH and UG Service w/Retirements	**-**	-	-	3,636.08	-	-	-	-	-	6,595.35	-	-	-	10,231.43
113	Capital Improvement Projects	**560,000**	-	-	9,550.04	10,939.11	-	30,774.12	-	-	6,745.71	-	54,908.48	388,885.88	501,803.34
300	Misc System Improvements	**15,000**	10,074.43	-	13,318.99	-	13,253.05	7,704.56	40,611.76	6,152.69	-	10,154.48	14,229.73	8,684.28	124,183.97
301	Pole for Additional Height	**10,000**	-	-	-	-	2,690.23	1,002.66	-	-	-	2,148.00	-	-	5,840.89
302	Customer request line change	**-**	-	-	-	-	-	-	-	-	-	-	-	-	-
303	Ordinary Replacement	**-**	-	-	-	-	-	-	-	-	-	-	-	-	-
305	Storm Damage	**20,000**	-	-	3,239.10	-	-	-	-	2,746.04	1,694.24	-	7,065.95	-	14,745.33
400	Motor Vehicle Accidents	**-**	-	-	3,730.52	-	-	4,037.94	-	-	-	1,069.35	-	7,653.00	16,490.81
600	Special Equipment	**-**	-	-	-	-	-	-	-	-	-	-	-	10,220.64	10,220.64
601	Transformer-replacement/Upgrade	**8,000**	-	-	-	-	-	-	-	-	-	-	-	-	-
602	Transformer's-Cost	**25,000**	19,000.00	-	-	-	14,950.00	41,785.00	10,175.00	-	-	-	9,590.00	-	95,500.00
603	Cutouts/Sectionilizing	**-**	-	-	-	-	-	-	-	-	-	-	-	-	-
604	Regulator's	**-**	-	-	-	-	-	-	-	-	-	-	-	-	-
605	Capacitor's	**-**	-	-	-	-	-	-	-	-	-	-	-	-	-
606	Anchor's & Guy Replacement	**2,000**	-	-	-	-	-	-	-	-	-	-	-	-	-
607	Pole Replacement's	**750,000**	39,251.98	62,362.23	89,558.38	46,453.23	37,318.79	77,285.27	5,262.05	91,586.79	84,737.11	63,844.47	61,296.95	4,900.73	663,857.98
608	Reliability Improvement's	**69,600**	21,965.83	583.61	-	-	2,607.20	1,409.23	-	-	-	-	1,241.30	-	27,807.17
609	Install Ground's	**-**	-	-	-	-	-	-	-	-	-	-	-	-	-
610	Oil Circuit Reclosurer's-OCR's	**-**	-	12,363.90	-	-	-	-	-	-	-	-	32,552.20	-	44,916.10
700	Street Light's	**55,000**	1,338.69	519.29	435.17	898.74	-	-	-	-	868.12	225.35	648.16	-	4,933.52
701	Customer Outdoor Light's	**40,000**	8,458.63	21,339.82	13,740.83	8,520.47	12,831.46	8,036.88	7,684.37	24,580.39	17,050.53	3,240.75	15,725.07	9,826.50	151,035.70
702	Make Ready Work	**-**	-	-	-	7,190.05	-	-	-	-	-	-	-		7,190.05
703	Solar Make Ready Work	**-**	-	-	-	-	-	-	-	-	-	-	-		-
000	Retirement	**5,000**	-	-	-	-	240.32	-	-	-	-	-	-	5,195.14	5,435.46
	Construction Total	**1,689,600**	100,089.56	105,433.59	152,556.39	74,928.66	92,843.23	203,288.09	70,138.95	161,132.17	144,753.19	163,707.88	197,257.84	1,218,625.20	2,684,754.75
	Misc														
#362.00	Substation	**3,000**	-	-	-	-	-	-	-	-	-	66.74	-	-	66.74
#370.00	Meters	**20,000**	-	-	-	-	-	-	9,150.00	-	-	-	-	-	9,150.00
#390.00	Office - Structure & Improvements	**-**	-		-	-	-	-	1,022.90	-	1,953.04	28,400.00	1,107.70	45,785.10	78,268.74
#391.00	Office - Furniture & Equipment/IT	**45,375**	-	2,183.60	3,188.48	-	-	196.10	392.20	2,447.54	10,589.88	295.74	5,405.04	1,378.99	26,077.57
#394.00	Tools & Shop Equipment	**10,000**	1,338.78	-		23,544.39	-	-	-	-	-	-	-	881.36	25,764.53
#395.00	Equipment - outside	**-**	-	-		-	-	-	-	-	-	-	-	-	-
#396.00	Equipment - Power Operated	**-**	-	-		-	-	-	-	-	-	-	-	-	-
#397.00	Communication Equipment	**-**	-	-		-	3,205.00	-	-	6,214.78	-	-	-	2,059.58	11,479.36
	Misc Total	**78,375**	1,338.78	2,183.60	3,188.48	23,544.39	3,205.00	196.10	10,565.10	8,662.32	12,542.92	28,762.48	6,512.74	50,105.03	150,806.94
	Company Total	**1,767,975**	101,428.34	107,617.19	155,744.87	98,473.05	96,048.23	203,484.19	80,704.05	169,794.49	157,296.11	192,470.36	203,770.58	1,268,730.23	2,835,561.69
#392.00	Transportation Equipment	**191,000**	-	-	-	-	-	-	131,928.10	-	-	-	-	-	131,928.10

OSHA's Form 300A (Rev. 01/2004)

Summary of Work-Related Injuries and Illnesses

Note: You can type input into this form and save it.
Because the forms in this recordkeeping package are "fillable/writable" PDF documents, you can type into the input form fields and then save your inputs using the free Adobe PDF Reader.

Year 20 22

U.S. Department of Labor
Occupational Safety and Health Administration

Form approved OMB no. 1218-0176

All establishments covered by Part 1904 must complete this Summary page, even if no work-related injuries or illnesses occurred during the year. Remember to review the Log to verify that the entries are complete and accurate before completing this summary.

Using the Log, count the individual entries you made for each category. Then write the totals below, making sure you've added the entries from every page of the Log. If you had no cases, write "0."

Employees, former employees, and their representatives have the right to review the OSHA Form 300 in its entirety. They also have limited access to the OSHA Form 301 or its equivalent. See 29 CFR Part 1904.35, in OSHA's recordkeeping rule, for further details on the access provisions for these forms.

Number of Cases

Total number of deaths	Total number of cases with days away from work	Total number of cases with job transfer or restriction	Total number of other recordable cases
0	0	0	0
(G)	(H)	(I)	(J)

Number of Days

Total number of days away from work	Total number of days of job transfer or restriction
0	0
(K)	(L)

Injury and Illness Types

Total number of . . . (M)			
(1) Injuries	0	(4) Poisonings	0
(2) Skin disorders	0	(5) Hearing loss	0
(3) Respiratory conditions	0	(6) All other illnesses	0

Post this Summary page from February 1 to April 30 of the year following the year covered by the form.

Public reporting burden for this collection of information is estimated to average 50 minutes per response, including time to review the instructions, search and gather the data needed, and complete and review the collection of information. Persons are not required to respond to the collection of information unless it displays a currently valid OMB control number. If you have any comments about these estimates or any other aspects of this data collection, contact: US Department of Labor, OSHA Office of Statistical Analysis, Room N-3644, 200 Constitution Avenue, NW, Washington, DC 20210. Do not send the completed forms to this office.

Establishment information

Your establishment name: Wellsboro Electric Co.

Street: 33 Austin St

City: Wellsboro State: PA Zip: 16901

Industry description (*e.g., Manufacture of motor truck trailers*)
Electric Distribution Utility

Standard Industrial Classification (SIC), if known (*e.g., 3715*)

OR

North American Industrial Classification (NAICS), if known (e.g., 336212)
221122

Employment information *(If you don't have these figures, see the Worksheet on the next page to estimate.)*

Annual average number of employees: 18

Total hours worked by all employees last year: 36518

Sign here

Knowingly falsifying this document may result in a fine.

I certify that I have examined this document and that to the best of my knowledge the entries are true, accurate, and complete.

Company executive _____ Title _____

Phone ____ - ____ - ____ Date ____ / ____ / ____

Save Input

OSHA's Form 300A (Rev. 01/2004)

Summary of Work-Related Injuries and Illnesses

Note: You can type input into this form and save it.
Because the forms in this recordkeeping package are "fillable/writable" PDF documents, you can type into the input form fields and then save your inputs using the free Adobe PDF Reader.

Year 20 23

U.S. Department of Labor
Occupational Safety and Health Administration

Form approved OMB no. 1218-0176

All establishments covered by Part 1904 must complete this Summary page, even if no work-related injuries or illnesses occurred during the year. Remember to review the Log to verify that the entries are complete and accurate before completing this summary.

Using the Log, count the individual entries you made for each category. Then write the totals below, making sure you've added the entries from every page of the Log. If you had no cases, write "0."

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Number of Cases

Total number of deaths	Total number of cases with days away from work	Total number of cases with job transfer or restriction	Total number of other recordable cases
0	0	0	0
(G)	(H)	(I)	(J)

Number of Days

Total number of days away from work	Total number of days of job transfer or restriction
0	0
(K)	(L)

Injury and Illness Types

Total number of . . . (M)			
(1) Injuries	0	(4) Poisonings	0
(2) Skin disorders	0	(5) Hearing loss	0
(3) Respiratory conditions	0	(6) All other illnesses	0

Post this Summary page from February 1 to April 30 of the year following the year covered by the form.

Public reporting burden for this collection of information is estimated to average 50 minutes per response, including time to review the instructions, search and gather the data needed, and complete and review the collection of information. Persons are not required to respond to the collection of information unless it displays a currently valid OMB control number. If you have any comments about these estimates or any other aspects of this data collection, contact: US Department of Labor, OSHA Office of Statistical Analysis, Room N-3644, 200 Constitution Avenue, NW, Washington, DC 20210. Do not send the completed forms to this office.

Establishment information

Your establishment name: Wellsboro Electric Co.

Street: 33 Austin St

City: Wellsboro State: PA Zip: 16901

Industry description (*e.g., Manufacture of motor truck trailers*)
Electric Distribution Utility

Standard Industrial Classification (SIC), if known (*e.g., 3715*)

OR

North American Industrial Classification (NAICS), if known (e.g., 336212)
221122

Employment information *(If you don't have these figures, see the Worksheet on the next page to estimate.)*

Annual average number of employees: 17

Total hours worked by all employees last year: 36780

Sign here

Knowingly falsifying this document may result in a fine.

I certify that I have examined this document and that to the best of my knowledge the entries are true, accurate, and complete.

Company executive: Peter E. Yost Title: VP Safety & Compl

Phone: 570-522-6179 Date: 01/11/2024

Save Input

OSHA's Form 300A (Rev. 01/2004)

Summary of Work-Related Injuries and Illnesses

Note: You can type input into this form and save it.
Because the forms in this recordkeeping package are "fillable/writable" PDF documents, you can type into the input form fields and then save your inputs using the free Adobe PDF Reader.

Year 20 24

U.S. Department of Labor
Occupational Safety and Health Administration

Form approved OMB no. 1218-0176

All establishments covered by Part 1904 must complete this Summary page, even if no work-related injuries or illnesses occurred during the year. Remember to review the Log to verify that the entries are complete and accurate before completing this summary.

Using the Log, count the individual entries you made for each category. Then write the totals below, making sure you've added the entries from every page of the Log. If you had no cases, write "0."

Employees, former employees, and their representatives have the right to review the OSHA Form 300 in its entirety. They also have limited access to the OSHA Form 301 or its equivalent. See 29 CFR Part 1904.35, in OSHA's recordkeeping rule, for further details on the access provisions for these forms.

Number of Cases

Total number of deaths	Total number of cases with days away from work	Total number of cases with job transfer or restriction	Total number of other recordable cases
0	0	0	0
(G)	(H)	(I)	(J)

Number of Days

Total number of days away from work	Total number of days of job transfer or restriction
0	0
(K)	(L)

Injury and Illness Types

Total number of . . . (M)			
(1) Injuries	0	(4) Poisonings	0
(2) Skin disorders	0	(5) Hearing loss	0
(3) Respiratory conditions	0	(6) All other illnesses	0

Post this Summary page from February 1 to April 30 of the year following the year covered by the form.

Public reporting burden for this collection of information is estimated to average 50 minutes per response, including time to review the instructions, search and gather the data needed, and complete and review the collection of information. Persons are not required to respond to the collection of information unless it displays a currently valid OMB control number. If you have any comments about these estimates or any other aspects of this data collection, contact: US Department of Labor, OSHA Office of Statistical Analysis, Room N-3644, 200 Constitution Avenue, NW, Washington, DC 20210. Do not send the completed forms to this office.

Establishment information

Your establishment name: Wellsboro Electric Co.

Street: 33 Austin St

City: Wellsboro State: PA Zip: 16901

Industry description (*e.g., Manufacture of motor truck trailers*)
Electric Distribution Utility

Standard Industrial Classification (SIC), if known (*e.g., 3715*)

OR

North American Industrial Classification (NAICS), if known (e.g., 336212)
221122

Employment information *(If you don't have these figures, see the Worksheet on the next page to estimate.)*

Annual average number of employees: 17

Total hours worked by all employees last year: 36721

Sign here

Knowingly falsifying this document may result in a fine.

I certify that I have examined this document and that to the best of my knowledge the entries are true, accurate, and complete.

Company executive: [signature] Title: Safety Director

Phone: 570 - 724 - 5814 Date: 1 / 20 / 25

Save Input

BEFORE
THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	**Docket No. R-2025-3054392**
	:	
Wellsboro Electric Company	:	

REBUTTAL TESTIMONY AND EXHIBIT

OF

BYRON FARNSWORTH, JR.

ON BEHALF OF

WELLSBORO ELECTRIC COMPANY

AUGUST 13, 2025

BEFORE
THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	**Docket No. R-2025-3054392**
	:	
Wellsboro Electric Company	:	

REBUTTAL TESTIMONY OF BYRON FARNSWORTH, JR. ON BEHALF OF WELLSBORO ELECTRIC COMPANY

Q. Please state your name and business address.

A. My name is Byron (Barney) Farnsworth, Jr., and my business address is 33 Austin Street, Wellsboro, Pennsylvania.

Q. Are you the same Byron (Barney) Farnsworth, Jr., who previously submitted Direct Testimony in this proceeding on behalf of Wellsboro Electric Company ("Wellsboro")?

A. Yes, Terms defined in my direct testimony have the same meaning in this rebuttal testimony.

Q. What is the purpose of your testimony today?

A. The purpose of my testimony is to rebut the testimony of the Office of Consumer Advocate ("OCA") witness Greg Meyer, OCA witness LeeAnn Wise, Office of Small Business Advocate ("OSBA") witness Justin Farr and Bureau of Investigation and Enforcement ("I&E") witness Christopher Keller regarding Performance Adjustment, Size Adjustment, Wage and Salary justification, Security Deposits, Payment Plans, Advertising Expense, Miscellaneous Expenses (588) and Rate Case Amortization timeframe.

Q. Do you agree with OSBA witness Justin Farr and I&E witness Christopher Keller's rejection of Performance and Size Adjustments?

A. No, Mr. D'Ascendis will discuss the reasons why the Pennsylvania Public Utility Commission ("Commission" or "PUC") should again recognize the size adjustment. I will address the performance adjustment.

The Company has made significant improvements to the reliability and resiliency of the WECO distribution system over the past seven years. As a result, the Company has experienced a reduction in customer complaints. The majority of complaints relate to payment plans and are typically resolved in the Company's favor.

PAPUC Complaints (WECO)

	2018	2019	2020	2021	2022	2023	2024	2025
Informal	4	4	1	1	2	5	3	1
Formal	0	1	0	0	0	0	0	0

Customer survey responses have remained very positive over the past seven years for the Company. This is a testament to our employees who know our customers and are very responsive to their needs. I have received positive feedback during local meetings and from local organizations I am involved with, commending the Company for its improved reliability and maintaining consistent power supply.

Over the past seven years, the Company has systematically implemented capital projects to improve the overall reliability and resilience of the WECO distribution system. This work has been executed in phases, beginning with enhancements to the transmission feed and substation, followed by improvements to the three-phase circuits, and finally work continues on all remaining lines that serve the Company's customers.

In 2019 and 2020, the Company upgraded its substation to accommodate a new 115 kV transmission line being constructed by FirstEnergy MAIT. This upgrade eliminated outages previously attributed to the "Power Supplier" category across the entire service territory, stabilized system voltage regulation, and reduced the Tap Changer movement by half, which reduced our maintenance costs. The project also reduced costs for our customers by eliminating FirstEnergy's monthly "Other Supporting Facilities" charge.

The Company also began two voltage conversion projects in the downtown area to transition the last two circuits to the main substation. These conversions addressed persistent outages experienced in 2016–2018, allowed for the completion of AMI meter installations, and supported the development of tie-points (loop feeds) to enhance system flexibility.

Since 2020, the Company has been actively reconductoring its three-phase lines, further supporting the development of tie-points and providing backup feeds for each circuit. These efforts have increased redundancy, reduced outage durations, and improved storm resilience throughout the system.

Additionally, the Company has expedited its wood pole replacement program. Over the past seven years, this initiative has lowered historical pole failure rates from 12–15% to under 5% during 2025 testing. The failure rate is expected to continue declining through 2027 toward an industry standard of 1-2%.

Finally, the Company installed vacuum reclosers that replaced aging and high maintenance hydraulic reclosers. This modernization has contributed to reduced outages and helped the Company control maintenance costs over the past seven years.

Q. Please discuss the benefits of consistent regulatory treatment for Wellsboro.

A. When we are planning our system improvements and projecting our future financial situation, we rely on receiving consistent treatment by the Commission. This includes certainty on items such as the recognition of the size and performance adjustments, which the Commission granted to us in the past.

Q. Do you agree with OCA witness Greg Meyer that WECO payroll should be reduced?

A. No, our payroll expense has been fully supported and should be approved. We provided support demonstrating how the 2024 (HTY) payroll will increase over the FTY and FPFTY through a combination of base compensation increases, merit increases and market adjustments to reflect the results of the Wage & Salary Study. Mr. Meyer advocates for a simplistic 4% annual increase in place of our more detailed calculation. This should be rejected.

The Company conducted a comprehensive review of employee wages during 2024 led by a third-party consultant hired by C&T Enterprises, Inc. ("C&T"). The purpose of the Wage & Salary (W&S) study was to evaluate existing wage grades and assess how employees were positioned within those grades. This was the first corporate-wide W&S study in over a decade, and it followed the identification of employee compensation as a corporate risk during the COVID-19 pandemic. Ensuring competitive wages was deemed essential for employee retention, business continuity, and cost stability.

The study concluded that, overall, the Company's wages were below market. To address this, a phased adjustment process was implemented in January 2025 with some employees receiving targeted adjustments over a one to two year period to bring compensation closer

to market levels. This approach was selected to balance fairness to employees with our responsibility to the ratepayers.

The Company recognized the importance of long-term wage competitiveness and will be reviewing wages annually with the help of the third-party consultant to keep wages close to market. Our Exhibit JC-5 provided a year-by-year breakdown of salary adjustments for union and non-union employees. OCA was provided access to extensive data in discovery, including the actual salary plan results for all of the non-union employees. Mr. Meyer ignores this evidence and instead relies on his observational experience. The Company's wage expenses are reasonable based on the 2024 W&S study and the other supporting evidence. Mr. Meyer's adjustment should be rejected.

Q. I&E proposes to use a sixty-month (five year) rate case normalization period based on the average time between Wellsboro's last three rate cases. Please explain why a three year normalization period is appropriate.

A. Wellsboro's last three rate cases were filed in 2016, 2019 and 2025. Our sister-affiliates Citizens' Electric Company of Lewisburg PA ("Citizens'") and Valley Energy, Inc. ("Valley") filed rate cases in 2022; however, Wellsboro did not join with Citizens' and Valley. Generally, Wellsboro, Citizens' and Valley attempt to coordinate filing schedules so we can share a portion of the litigation costs and expert witness fees; however, in 2022 several factors went into the decision for the Company not to file for a rate increase in 2022.

First, the Company's financial projections in 2022 showed that a rate case would not be cost-effective for our ratepayers. Even with the cost sharing that I previously discussed, rate cases are expensive for the ratepayers and require significant internal resources. These

factors must be balanced against the rate increase that could be expected to result from the filing. Due to several unique developments, our revenues were sufficient to support a reasonable overall return.

To maintain our financial outlook, we managed operating expenses and supplemented our revenues by securing grant funding through the Paycheck Protection Program ("PPP") and Tioga County grant opportunities. Those funding sources were tied to the COVID-19 pandemic, which is a unique and non-recurring situation.

In addition, we undertook efforts to increase non-customer revenues from pole attachments. Back in 2018, the Company performed an asset verification project with Davey Resources that found hundreds of attachments that were not being captured. The Company then proceeded to back bill for those attachments which recovered approximately $120,000 in additional "Other Revenue" during 2019 and 2020. Going forward, the Company then saw growth in pole attachments due to an initial push for broadband services in the area around COVID in 2020. As Tri-County Rural Electric Cooperative constructed its broadband network, other broadband providers also upgraded their facilities on our poles. Additionally, the Company renegotiated its pole attachment agreements to include the Federal Communications Commission ("FCC") formula rate that adjusts each year, ensuring that attachment rates remain aligned with the costs associated with ongoing system upgrades. Finally, the Company implemented an application fee to cover administrative costs while reviewing the application(s) and to perform a system evaluation to confirm pole attachment application data.

Wellsboro also saw unusual growth in regulated revenues. From 2020-2025 the Company saw growth from the Marcellus shale gas industry in our service territory. Those companies

requested significant three-phase builds/rebuilds on the distribution system to serve their expansion plans. On average, the Company has energized approximately one new account per year in the 400 kW to 1,200 kW range. These additions have helped the Company maintain flat to slightly positive revenue growth, contributing to the Company's return on equity ("ROE") exceeding the PUC-approved level. Many of these new accounts are expected to operate for five years before they are retired from service, which does not support long- term company revenue growth.

Q. Do you anticipate that similar factors will recur to enable the Company to avoid a rate case for the next five years?

A. No, the circumstances outlined above are very extraordinary. Although the pole attachment changes result in ongoing benefits, the revenue infusion that we experienced in the last five years will not occur again. Similarly, the additional accounts from the Marcellus activity have limited durations. We anticipate that we will return to a three-year filing interval for our next rate case.

Q. Do you agree with OCA witness Greg Meyer requesting the Company use ten or fifteen-year periods to calculate customer growth and revenue values?

A. No, there are several factors that have led to flat or declining revenues. These factors include a lower kilowatt sales usage by customers and an increase in net metered installations. The Wellsboro area had a robust Industrial base up until 2016 when two large industrial customers abruptly ceased operations without new customers replacing them in the territory. The system peak in 2016 was 24.1 MWs and has continually declined to the current value of 18.0 MWs in 2025. Using ten or fifteen-year sales data is unrealistically high and thus will significantly overstate any realistic revenue estimates for the Company.

The local area faces limited availability of property and housing, which has contributed to flat customer growth. The primary source of growth in recent years has come from the addition of second meters on existing properties, typically for garages. However, these garages tend to have minimal load, primarily limited to lighting, which offers little impact on overall system usage. While this may result in a slight increase in customer count, it simultaneously reduces the average usage per customer. The broader trend of declining usage is largely driven by customer energy efficiency and conservation efforts, supported by advancements in technology such as Energy STAR appliances, LED lighting, and other energy-saving devices used in everyday life. As more solar installations have increased over the past 3-4 years, more customers/developers are taking advantage of current Net Metering rules which have led to lower distribution revenues. Another shortcoming of Net Metering is that customers are compensated at the full retail rate, a price well above market pricing for their excess generation impacting distribution ROE. Based on the rapid change in energy with accelerated growth of solar installations under net metering, increased energy efficiency and conservation over the past 5–6 years, it is more appropriate to use a five-year sales forecast when developing the Company's revenue projections.

Q. Please address I&E's proposal to disallow Wellsboro's entire claim for Account 588 (Miscellaneous Distribution Expenses)?

A. Ms. Campbell provides a detailed explanation of the costs in Account 588. It is important to note that the Company manages our workforce based on our needs and these choices are evaluated with the best operational and financial decision in mind for ratepayers and the Company. The size of our workforce is small and consistent; however, if we have to change the duties assigned to an individual employee due to special projects, regulatory

requirements or absences, the expenses in our individual accounts will follow that reassignment. We expect our employees to cross-train and to be flexible in helping with shifting project needs.

Shifting just one Full-Time Employee ("FTE") can significantly impact an annual budget based on the size of the Company. The Company has eight employees in the field to carry out metering, line maintenance and capital work. One of the FTEs was used exclusively to meet the PUC mandated Inspection and Maintenance ("I&M") plan that the Company is required to perform each year. The Company experienced a retirement a few years ago that was backfilled with one FTE. Based on the Maintenance work and Capital improvements the Company has performed on the distribution system it was found that the I&M work took less time to complete. The Company had a vacant lineman position and the employee working on I&M showed interest in becoming a line worker. The employee that was performing I&M work completed his work in the first half of the year and then was shifted to work with the linemen during the second half of the year. The Company had budgeted for a resource for the second half of 2025 and may look at it again in the future. Based on the negative financial start in 2025 we have opted to hold on to the Part-Time ("PT") resource and have chosen to complete the 2025 I&M work by shifting a lineman to perform the required I&M inspections. The Company will be evaluating the effectiveness of the shared resource at the end of 2025.

The Company also employs a fully qualified outdoor workforce. During COVID and for a couple years following it was difficult to get any external training completed. Training was implemented again in 2024 and moving into future years. Account 588 contains training costs. It is very important for the Company to continuously train our outside workforce to

keep their skills sharp for the purpose of re-emphasizing and implementing safe work practices. The training keeps the workforce retrained and sharp while teaching employees about new tools, equipment and practices in the industry. As a small Electric Distribution Company ("EDC"), it is important that we keep training continuously to maintain a fully qualified workforce. Otherwise, the resources available in our area each year are limited, and any workforce reduction would increase costs, lead to decreased efficiency and potentially impact safety in the future.

Q. How are Advertising Expenses important to the Wellsboro area and the Company?

A. The Company's advertising expenses are limited and primarily focused on supporting local community activities within our service territory. The Company is a major business in the area, so advertising efforts reinforce the Company's strong presence in the community. This contributes to initiatives that may otherwise lack visibility or funding, such as the broadcasting of local sporting events that help foster community spirit and engagement. In conjunction with this support, the Company incorporates energy efficiency messaging into its advertising to help educate customers on ways to manage their energy use. These dollars serve a dual purpose, community support and customer education, to ensure that advertising dollars provide value both in terms of public engagement and responsible energy stewardship. The loss of advertising would be harmful to our local community that lacks a wide breath of business support in our remote area of the state.

Q. Are you in agreement with OCA witness LeeAnn Wise's thoughts about the handling of Payment Plans?

A. No, I respectfully disagree and am genuinely concerned with OCA witness Wise's characterization of the Company's Payment Plan administration. Witness Wise asserts "the

absence of such oversight may reflect a lack of due diligence and raise concerns about the company's ability to manage financial risk or make informed decisions regarding customer repayment strategies." This assertion reflects a misunderstanding of the legal and regulatory framework under which EDCs in Pennsylvania must operate. I would encourage the witness to further review the applicable regulations under Chapter 14 of the Public Utility Code and Chapter 56 of the Commission's regulations, which govern how EDCs manage customer accounts and interactions. Our employees are very well versed in these requirements and use them daily while serving our customers. The lack of a formal "procedure" or a "study" with "metrics" should in no way be construed as our employees or the Company lacking the knowledge to run the business. To the contrary, a high percentage of our customer surveys acknowledge the fact that our employees get the job done.

The Company has built a knowledgeable and responsive organization, fully aligned with these requirements. Our employees are locally staffed and receive ongoing training to ensure compliance and effective customer service. Because our employees live in and are part of the community we serve, they bring unique insight into the needs of our customer base. This community connection allows our employees to engage more effectively with customers, directing them toward appropriate solutions such as budget billing, payment arrangements, or available assistance programs like LIHEAP, the Dollar Energy Fund, and programs that were available during COVID such as ERAP and PAHAF. Overdue account balances are reported monthly to senior management, and our staff has consistently done an exceptional job in monitoring and managing those balances, keeping them at manageable levels and minimizing the risk of uncollectible accounts. Historically, the

Company's write-off levels have remained reasonable due to these diligent and locally informed practices. The Company sees a typical Delinquent ("DQ") % to Accounts Receivable averaging 17% for 2020-2024 and 2025 is averaging 14%, this is a testament to the work performed by our employees to stay on top of the DQ balances.

Q. Please discuss why the OCA's proposed payment arrangement study and metrics are not appropriate.

A. The OCA's suggestion that we conduct a study of payment arrangement and establish metrics to evaluate our effectiveness is not necessary and, in my opinion, unworkable. At the core, the OCA's witness assumes that the Company will be able to pinpoint a reason for a customer failing to adhere to a payment arrangement. In our experience, however, many factors influence customer behavior.

A significant portion of our customer base consists of hardworking individuals who take great pride in their independence and often find it difficult to seek assistance. Some choose not to pursue help from available programs because they believe others are in greater need, or they feel uncomfortable with the experience of engaging with assistance organizations. As a result, some customers who may benefit from support decline to access those resources.

At the same time, the Company has observed a small subset of customers who, despite having the financial means to pay their bills, intentionally attempt to delay payment by exploiting provisions of Chapter 14. This behavior became particularly evident during the COVID-19 moratorium period. These customers may file repeated or frivolous complaints with the PUC's Bureau of Consumer Services ("BCS") to delay collections, especially as the Winter Moratorium approaches. Others misuse medical certificates or repeatedly break

payment agreements in order to postpone payment obligations. Unfortunately, these delays often lead to significantly higher arrearage balances, making it more difficult for the customer to become current, increasing the risk of disconnection for non-payment, which increases write-offs and supports the need to collect a security deposit.

We believe the OCA's study and metrics will be an administrative burden that produces little statistically valid information for our Company. We comply with Chapter 56 and the Commission's reporting requirements. Additional studies and metrics are not warranted.

Q. OCA Witness Wise also requests changes to the Company's security deposit policies. Please comment.

A. The OCA request that we engage in additional income screening before we request a security deposit and that we provide low-income customers with the option to receive the full security deposit back rather than applying it to outstanding charges first.

We have collected security deposits consistently across our customer base utilizing Chapter 14 regulations based on the applicant's creditworthiness. The Company utilizes Online Utility Exchange for all Residential applications to determine creditworthiness. If the credit check determines a security deposit is required, the applicant is provided with a Denial of Credit Statement outlining why a security deposit is required. The Company is open to incorporating language to inform customers of the opportunity to qualify for a waiver as part of the Denial of Credit Statement. If it is determined that the applicant is low income, Chapter 56 waiver guidelines will be followed.

For the return of security deposits, we believe that it is appropriate to follow a consistent policy for all customers, rather than creating a separate policy for the return of security deposits for low-income customers.

Q. Finally, Witness Wise objects to Wellsboro requiring ratepayers to pay the third-party credit card convenience fees of $3.95. Does Wellsboro agree with this proposal?

A. No, first, it is important to clarify that the Company does not charge the $3.95 convenience fee. This fee is assessed by the third-party credit card processing company that handles credit, debit, and electronic check payments. The fee is intended to cover the processing costs incurred by that vendor and is not retained by the Company.

While it was noted that customers have other payment options that do not include the $3.95 fee, those alternatives are not cost-free for the customer. For example, customers who mail a check bear the cost of purchasing the check itself and paying for postage, which continues to rise. Customers who choose to pay in person incur fuel or transportation expenses. Similarly, customers who use their own bank's online bill pay system may be subject to fees charged by their financial institution.

The Company believes customers should have the freedom to choose their preferred payment method—and the associated costs—without shifting the burden of credit/debit card processing fees onto the ratepayers. Additionally, customers who choose to pay by credit card may do so to earn rewards or benefits that can offset the cost of the convenience fee. Increasingly, local businesses are itemizing credit card processing fees as separate charges rather than absorbing them, due to the growing cost of payment processing. It is common practice for businesses to apply "cash" versus "card" pricing to manage these costs, and the Company's current approach aligns with this broader trend.

Q. If the Commission determines that the cost of the third-party service should be added to distribution rates, is the OCA's proposed adjustment sufficient?

A. No, we are very concerned that credit card payments will increase if it becomes a free option. Attached as Exhibit BF-1R is information from a New York utility that saw a substantial increase in the use of credit card payments when it became a free option. As a result, we should be allowed to track all costs in excess of the amount that OCA has calculated for inclusion in distribution rates and recover those costs, with appropriate carrying charges, in a subsequent proceeding.

Q. Does this complete your Rebuttal Testimony?

A. Yes.

BEFORE
THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	**:**	
	:	
v.	**:**	**Docket No. R-2025-3054392**
	:	
Wellsboro Electric Company	**:**	

EXHIBIT

OF

BYRON FARNSWORTH, JR.

ON BEHALF OF

WELLSBORO ELECTRIC COMPANY

AUGUST 13, 2025

Corning Natural Gas

EXHIBIT__(BF-1R)

	actual	actual	actual	actual	actual	actual	actual	approved in rate case				
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
# of transactions	11,590	19,240	25,575	30,063	39,253	45,913						
% increase		66.01%	32.93%	17.55%	30.57%	16.97%						
*fees		$ 46,176	$ 52,242	not available	$ 66,288	$ 78,683	$ 98,344	$ 107,914	$ 114,872	$ 120,839	$ 125,556	$ 129,679
% increase						18.70%	24.99%	9.73%	6.45%	5.19%	3.90%	3.28%

eliminated fee

*fees - credit/debit varied by type of payment, not a single fee.

BEFORE
THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	**:**	
	:	
v.	**:**	**Docket No. R-2025-3054392**
	:	
Wellsboro Electric Company	**:**	

SURREBUTTAL TESTIMONY

OF

BYRON FARNSWORTH, JR.

ON BEHALF OF

WELLSBORO ELECTRIC COMPANY

AUGUST 28, 2025

BEFORE
THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	**:**	
	:	
v.	**:**	**Docket No. R-2025-3054392**
	:	
Wellsboro Electric Company	**:**	

SURREBUTTAL TESTIMONY OF BYRON FARNSWORTH, JR.
ON BEHALF OF WELLSBORO ELECTRIC COMPANY

Q. Please state your name and business address.

A. My name is Byron (Barney) Farnsworth, Jr., and my business address is 33 Austin Street, Wellsboro, Pennsylvania.

Q. Are you the same Byron (Barney) Farnsworth, Jr., who previously submitted Direct Testimony and Rebuttal Testimony in this proceeding on behalf of Wellsboro Electric Company ("Wellsboro")?

A. Yes. Terms defined in my Direct Testimony or Rebuttal Testimony have the same meaning as in this Surrebuttal Testimony.

Q. What is the purpose of your Surrebuttal Testimony?

A. My Surrebuttal Testimony will respond to certain issues raised during the August 21, 2025, Public Input Hearings, including general comments and more specifically: (1) the testimony of Mrs. Cheryl Kaminski (Tr. 110) regarding a billing question; and (2) the testimony of Mrs. Candace Callahan regarding a tree trimming matter (Tr. 103).

Q. Please respond to the general concerns raised during the Public Input Hearings about the impact of the rate increase on residents of Wellsboro.

A. The Company takes customer affordability very seriously as we serve the Wellsboro residents. We have taken reasonable steps to operate efficiently, and we continually make improvements. There are several steps, which I spoke about in my Direct Testimony and Rebuttal Testimony, that the Company took to delay the need for a rate case over the past six (6) years. Growth in the natural gas business in the area provided revenue for a few years after the last rate case; however, the duration for most of these projects is limited to roughly five (5) years, meaning these revenue streams will not continue to recur. Also, the Company reviewed all pole attachment agreements, implemented new agreements, and then back-billed pole attachers for several years of unbilled attachments, which provided $120K in Other Revenue. The Company proactively secured Paycheck Protection Program (PPP) and Tioga County grant opportunities to offset expenses. The Company has continually monitored spending over the past six (6) years and has only purchased items if they were deemed essential or purchased to address a safety deficiency. There has been an efficiency directive established by management for the Company to utilize our existing National Information Solutions Cooperative ("NISC") system more efficiently (service orders, work orders, meter orders, inspection data capture, corporate assets, etc.) and remove the use of standalone spreadsheets, which carry considerable risk of human error. The Company completed the Advanced Metering Infrastructure ("AMI") project back in 2019 to automate all meter readings into the NISC system for billing and removed all manual meter reading, which essentially eliminates the chance for erroneous reads.

Q. Did the Company follow up with Mrs. Kaminski about her bill?

A. Yes, the Company was concerned that a printing error might have placed an "Activation Charge" on a bill(s) that we were unaware of at the time of the public meeting. Upon further review, the Company checked Mrs. Kaminski's bill and found nothing erroneous on it. Mrs. Kaminski checked her Wellsboro electric bill after the public meeting, called the office immediately to inform us that there was no "Activation Charge" on her bill, and also apologized for the confusion.

Q. Has the Company been contacted by Mr. or Mrs. Callahan regarding tree trimming?

A. Yes, the Company received a call from Mr. Callahan in June 2019 about a dead tree on his property. The Company met with Mr. Callahan and the tree was found to be 40' outside of the Company right-of-way. This tree was well outside the reasonable distance where the Company would consider removal of a tree for reliability purposes. Mr. Callahan was informed that the tree removal was his responsibility. He was also asked if he wanted contact information for tree companies to assist with removal of the tree, and he declined.

Q. Does this complete your Surrebuttal Testimony?

A. Yes.

BEFORE

THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	**:**	
	:	
v.	**:**	**Docket No. R-2025**
	:	
Wellsboro Electric Company	**:**	

DIRECT TESTIMONY

AND EXHIBITS

OF

JILL CAMPBELL

ON BEHALF OF

WELLSBORO ELECTRIC COMPANY

APRIL 30, 2025

BEFORE

THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	**:**	
	:	
v.	**:**	**Docket No. R-2025**
`	**:**	
Wellsboro Electric Company	**:**	

DIRECT TESTIMONY OF JILL CAMPBELL
ON BEHALF OF WELLSBORO ELECTRIC COMPANY

Q. Please state your name and business address.

A. My name is Jill Campbell, and my business address is 33 Austin Street, Wellsboro, Pennsylvania.

Q. By whom are you employed and in what capacity do you serve at Wellsboro Electric Company?

A. I am employed by C&T Enterprises, Inc. ("C&T"), and assigned to Wellsboro as the Vice President of Finance and Administration.

Q. Please describe your duties in this capacity.

A. My duties are to organize, direct, and coordinate the financial department. I provide administrative direction and oversight for billing for electric service to consumers. I also advise the President & CEO of the financial aspects of the company, manage the financial record keeping, coordinate the budget, coordinate with computer services, and coordinate with consumer services. I also am involved in the negotiation and administration of Wellsboro’s collective bargaining agreement (“CBA”) with its union workers.

Q. Please describe your employment and educational background.

A. I have a bachelor's degree from Pennsylvania State University as well as a Masters in Business Administration with Accounting concentration from Keller Graduate School of Management. I have been with C&T Enterprises assigned to Wellsboro Electric since June of 2014. I have served in various capacities in the company prior to being promoted to my current position as Vice President of Finance and Administration in May of 2019.

Q. What were your responsibilities with respect to this filing?

A. As the Vice President of Finance and Administration, I was responsible for coordinating with our auditors and representatives of HSG Group, Inc. ("HSG Group") to ensure that historic and test year expenses, taxes, revenues, and rate base are appropriately reflected.

Q. Are Wellsboro and its records regularly audited by a licensed accounting firm?

A. Yes. The accounting firm of FORVIS MAZARS, LLC ("FORVIS") audits the Company's financial records. Prior to FORVIS, BKD and Beard Miller Company, LLP performed the audits. They prepare an annual report of the Company operations and assist Company personnel on specific PUC filings, such as our State Tax Adjustment Surcharge ("STAS") filings. They also prepare our tax returns. A copy of our Annual Report for the year ended December 31, 2024, is attached as Exhibit __ (JC-1). A copy of our most recent Pennsylvania state tax return is included as Wellsboro Confidential Exhibit 3.

Q. Do you have any comments regarding the future test year expenses?

A. Yes. Attached as Exhibit __ (JC-3) is a table showing the operating expenses for the Historic Test Year ("HTY"), Future Test Year ("FTY") and Fully-Projected Future Test Year ("FPFTY"). Also enclosed are actual expenses in the FTY through March 31, 2025. Although there is some variation within particular categories and expenses, on the whole

our actual year 2025 expenses are tracking closely to the projected FTY expenses used by HSG Group in the filing. We will continue to update this information on a quarterly basis during the proceeding.

Q. Did you compile a similar comparison of future test year plant?

A. Yes. Attached as Exhibit __ (JC-4) is a table showing the utility plant for the HY, FTY and FPFTY, as well as actual plant as of March 31, 2025.

Q. Is Wellsboro proposing to roll-in its STAS?

A. Yes. Mr. Gorman has reflected the current levels of state taxes in his analysis. As a result, the current STAS is being rolled-into based rates. When the new rates take effect, we will adjust the then-applicable STAS rate to reflect any difference between the then-applicable tax levels and the ones that were rolled-into base rates. Our most recent STAS filing is included as Exhibit __ (JC-2).

Q. How does Wellsboro develop its annual budget?

A. As part of the budget process, Leadership reviews the goals and priorities of the company. Revenue is then forecasted based on an estimate of expected sales, customer growth, and approved rates. Each department then submits anticipated expenses which are then compiled to form the revenue and expenses budget. Capital expenditures are identified and budgeted separately. The consolidated budget is then reviewed internally by the management team and adjustments made when necessary to align with the strategic goals of the company. A final draft is then presented to the Board of Directors for approval to then be used as a guide throughout the fiscal year.

A copy of Wellsboro's 2025 budget and 5-year financial plan is included as Wellsboro Confidential Exhibit 2.

Q. Please discuss Wellsboro's major expense categories.

A. Wellsboro's expenses are budgeted and tracked in the following categories: (1) Labor & Overheads, including C&T Shared Services; (2) Transportation; (3) Materials & Supplies; (4) Administrative & General; (5) Outside Services; (6) Uncollectibles; (7) Depreciation & Amortization; (8) Regulatory Fees; and (9) Taxes. Wellsboro also reports by account, corresponding to the FERC chart of accounts. Each Operating and Maintenance account includes (as appropriate) costs for Labor, Overhead, Material and Transportation. The information provided to Mr. Gorman is by FERC account, with subaccounts for Labor, Overhead, Material and Transportation.

Q. What is the largest expense category?

A. Labor & Overheads constitute the largest expense item. This category includes our employees and the various benefits that we provide (health, dental, vision, retirement, etc.). To develop the projected 2025 costs for Labor & Overheads, we examined the wages and benefits for our employees. This included the impacts of the Wage & Salary Study discussed by Mr. Farnsworth and the annual compensation adjustment discussed by Ms. Sullivan. Ms. Sullivan's testimony discusses the C&T Shared Services and insurance benefits.

Q. How were Labor and Overhead costs projected for Wellsboro's union employees?

A. We have 8 Union employees who are covered by a collective bargaining agreement ("CBA"). The current CBA is included in the filing as Wellsboro Confidential Exhibit . The CBA expires at the end of 2026.

To develop the FTY and FPFTY, the union employees' salaries were adjusted from 2024 to 2025, and then from 2025 to 2026 based on the CBA.

Q. Have you prepared an exhibit showing the impact of the salary changes and the position changes for the FTY and FPFTY?

A. Yes. Attached as Exhibit__(JC-5) is an analysis that supports that impact. It also calculates the impact on the associated Overheads, using the benefits projections explained by Ms. Sullivan. We have assumed the same rate of change for the union benefits that we projected for the C&T employees. The impact of these changes are distributed among the various FERC accounts that Mr. Gorman reflects in his analysis according to where the employees' time is booked (based on activities performed).

Ms. Sullivan's testimony discusses the 2025 and projected 2026 C&T base compensation adjustments and our projections for personnel insurance benefits cost changes. Ms. Sullivan also discusses the C&T Shared Services that are included in our Labor & Overheads for 2024, 2025 and 2026.

Q. Please discuss the Transportation projections.

A. This item reflects the costs of our vehicles and other equipment, including fuel and maintenance expenses. For 2025 and 2026, we are projecting vehicle and equipment purchases, including a bucket truck in 2025.

Q. Is Wellsboro projecting increased Materials and Supplies costs?

A. Yes. The various materials and supplies for our business have increased consistent with general inflation of many items. We included a 3% increase for office supplies. Mr. Farnsworth will address the increases in our materials.

Q. Please discuss the costs incurred by Wellsboro for Administrative and General.

A. The items in this category include the general costs to heat, furnish and maintain our office space and warehouses.

Q. What costs are included in Outside Services?

A. Outside Services includes the charges by various vendors for their service. This includes attorneys, accountants, auditors, consultants, cleaning vendors and contractors that we hire for capital projects. Most of the construction contractor expense would be capitalized rather than expensed.

Q. Could costs in the other categories that you addressed above be capitalized rather than being expensed?

A. Yes. As part of this filing, we have made assumptions regarding the portion of Labor & Overheads, Transportation, Materials & Supplies and Administrative & General that will be capitalized rather than expensed. We have done this based on both historic experience and projected 2025 and 2026 capital projects.

Q. How did Wellsboro develop the Uncollectible expenses?

A. Uncollectible expense is based on historical experience.

Q. Please discuss the Depreciation and Amortization expense reflected in the filing.

A. Depreciation expense is developed by Mr. Gorman, Exhibit__(HSG-1), Schedule C3 and explained in his testimony.

Q. What depreciation changes is the Company proposing for this filing?

A. We are proposing to reduce the useful life of our computer equipment and software from 5 years to 3 years. This is consistent with the replacement cycle for IT equipment that we follow and is also consistent with the warranty period on new equipment. We are also proposing to reduce the useful life for power operated equipment from 33 to 25 years consistent with actual replacement cycles. If these changes are accepted by the Commission, we will make them going forward in 2026.

Q. Finally, what Regulatory Fees and Taxes are reflected in the filing?

A. These are developed by Mr. Gorman, Exhibit__(HSG-1), Schedule C1-3, and explained in his testimony.

WELLSBORO'S FINANCING ACTIVITIES

Q. Please explain the Company's financing arrangements.

A. Wellsboro's primary source of financing is its parent company, C&T., which obtains long-term loans, lines of credit and letters of credit on Wellsboro's behalf through the National Cooperative Servicing Corporation ("NCSC"). Each long-term loan is supported by a Securities Certificate approved by the Commission. Ms. Sullivan provides an exhibit with details of each loan. We also have access to a short-term line of credit through C&T, as described by Ms. Sullivan.

Finally, we maintain a local banking relationship with C&N Bank, Wellsboro, PA.

AFFILIATE CHARGES

Q. Does Wellsboro have any affiliate charges in the HTY, FTY or FPFTY in addition to the ones with C&T that are discussed by Ms. Sullivan?

A. No.

Q. Does this conclude your testimony at this time?

A. Yes.

BEFORE

THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	**:**	
	:	
v.	**:**	**Docket No. R-2025**
	:	
Wellsboro Electric Company	**:**	

EXHIBITS

OF

JILL CAMPBELL

ON BEHALF OF

WELLSBORO ELECTRIC COMPANY

APRIL 30, 2025

Wellsboro Electric Company

Independent Auditor's Report, Financial Statements and Supplementary Information

December 31, 2024 and 2023

Wellsboro Electric Company
Contents
December 31, 2024 and 2023

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Independent Auditor's Report

Board of Directors
Wellsboro Electric Company
Wellsboro, Pennsylvania

Opinion

We have audited the financial statements of Wellsboro Electric Company (Company), which comprise the balance sheets as of December 31, 2024 and 2023, and the related statements of operations, stockholders' equity, and cash flows for the years then ended, and the related notes to the financial statements.

In our opinion, the accompanying financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2024 and 2023, and the results of its operations and its cash flows for the years then ended in accordance with accounting principles generally accepted in the United States of America.

Basis for Opinion

We conducted our audits in accordance with auditing standards generally accepted in the United States of America (GAAS). Our responsibilities under those standards are further described in the "Auditor's Responsibilities for the Audit of the Financial Statements" section of our report. We are required to be independent of the Company and to meet our other ethical responsibilities, in accordance with the relevant ethical requirements relating to our audits. We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Responsibilities of Management for the Financial Statements

Management is responsible for the preparation and fair presentation of the financial statements in accordance with accounting principles generally accepted in the United States of America, and for the design, implementation, and maintenance of internal control relevant to the preparation and fair presentation of financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the financial statements, management is required to evaluate whether there are conditions or events, considered in the aggregate, that raise substantial doubt about the Company's ability to continue as a going concern within one year after the date that these financial statements are available to be issued.

Auditor's Responsibilities for the Audit of the Financial Statements

Our objectives are to obtain reasonable assurance about whether the financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditor's report that includes our opinion. Reasonable assurance is a high level of assurance but is not absolute assurance and therefore is not a guarantee that an audit conducted in accordance with GAAS will always detect a material misstatement when it exists. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control. Misstatements are considered material if there is a substantial likelihood that, individually or in the aggregate, they would influence the judgment made by a reasonable user based on the financial statements.

In performing an audit in accordance with GAAS, we:

- Exercise professional judgment and maintain professional skepticism throughout the audit.

- Identify and assess the risks of material misstatement of the financial statements, whether due to fraud or error, and design and perform audit procedures responsive to those risks. Such procedures include examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements.

- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control. Accordingly, no such opinion is expressed.

- Evaluate the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluate the overall presentation of the financial statements.

- Conclude whether, in our judgment, there are conditions or events, considered in the aggregate, that raise substantial doubt about the Company's ability to continue as a going concern for a reasonable period of time.

We are required to communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit, significant audit findings, and certain internal control-related matters that we identified during the audit.

Supplementary Information

Our audits were conducted for the purpose of forming an opinion on the financial statements that collectively comprise the Company's basic financial statements. The supplementary information listed in the table of contents is presented for purposes of additional analysis and is not a required part of the basic financial statements. Such information is the responsibility of management and was derived from and relates directly to the underlying accounting and other records used to prepare the basic financial statements.

The information has been subjected to the auditing procedures applied in the audit of the basic financial statements and certain additional procedures, including comparing and reconciling such information directly to the underlying accounting and other records used to prepare the basic financial statements or to the basic financial statements themselves, and other additional procedures in accordance with auditing standards generally accepted in the United States of America. In our opinion, the information is fairly stated in all material respects in relation to the basic financial statements as a whole.

Forvis Mazars, LLP

St. Louis, Missouri
March 12, 2025

Wellsboro Electric Company
Balance Sheets
December 31, 2024 and 2023

	2024	2023
ASSETS		
Utility Plant, at Cost		
Electric plant in service	$ 41,101,936	$ 36,030,374
Accumulated depreciation	(15,226,786)	(15,048,529)
	25,875,150	20,981,845
Construction work in progress	27,017	54,982
Net utility plant	25,902,167	21,036,827
Other Assets and Nonutility Property		
Nonutility property, net	144,043	147,228
Regulatory assets	40,145	31,474
Rentals and other	65,176	62,151
Total Other Assets and Nonutility Property	249,364	240,853
Current Assets		
Cash and cash equivalents	203,335	1,532,425
Accounts receivable:		
Customers, net of allowance 2024 - $12,306, 2023 - $20,165	1,186,224	1,380,833
Unbilled revenues	667,515	483,780
Other	287,005	323,873
Advances, affiliate	49,000	49,000
Inventories	247,983	334,040
Prepaid expenses and other	8,439	5,138
Prepaid taxes, net	108,863	135,655
Under collected power costs	72,766	19,231
Total Current Assets	2,831,130	4,263,975
Total Assets	$ 28,982,661	$ 25,541,655

See Notes to Financial Statements

	2024	2023
LIABILITIES AND STOCKHOLDERS' EQUITY		
Stockholders' Equity		
Preferred stock, 4% cumulative, $100 par value; authorized 2,000 shares; issued and outstanding, 2024 - 1,256 shares, 2023 - 1,258 shares	$ 125,800	$ 126,000
Common stock, par value $100 per share; authorized 2,000 shares; issued 1,123 shares; outstanding 1,055.5 shares	112,300	112,300
Additional paid-in capital	127,846	127,846
Retained earnings	5,050,799	5,200,624
	5,416,745	5,566,770
Treasury stock, at cost: 67.5 common shares	(159,250)	(159,250)
Total Stockholders' Equity	5,257,495	5,407,520
Long-Term Debt	18,477,675	15,380,234
Finance Lease Liabilities	349,544	422,484
Current Liabilities		
Current maturities of long-term debt	865,074	612,797
Current maturities of finance lease liabilities	129,214	127,363
Line of credit	700,000	-
Accounts payable		
Trade	520,911	525,183
Related party	133,216	136,794
Due for purchased electricity	537,362	540,438
Accrued expenses	227,799	210,705
Customer deposits	195,713	164,443
Deferred compensation	-	49,441
Total Current Liabilities	3,309,289	2,367,164
Deferred Charges and Other Liabilities		
Deferred income taxes	1,172,700	1,530,700
Accrued postretirement cost	185,579	190,178
Regulatory liability	230,379	243,375
Total Deferred Charges and Other Liabilities	1,588,658	1,964,253
Total Liabilities and Stockholders' Equity	$ 28,982,661	$ 25,541,655

Wellsboro Electric Company
Statements of Operations
Years Ended December 31, 2024 and 2023

	2024	2023
Operating Revenues	$ 13,158,392	$ 14,712,539
Operating Expenses		
Power	6,429,293	8,108,800
Distribution expenses		
Operation	253,121	236,392
Maintenance	1,085,382	1,040,748
Customer accounts	925,755	893,054
Sales expense, public relations	2,991	2,052
General and administrative	1,264,381	1,146,050
Depreciation	1,335,247	1,155,288
Taxes, other than income	814,557	857,783
	12,110,727	13,440,167
Operating Income Before Interest and Other Expenses	1,047,665	1,272,372
Other Income (Expenses)		
Interest income	38,238	93,563
Interest expense	(859,424)	(727,220)
Acquisition debt expense	(361,458)	(124,686)
Miscellaneous	27,835	35,454
Loss on disposal of utility plant and nonutility property	(81,514)	(164,327)
Other expense	(20,481)	(25,229)
	(1,256,804)	(912,445)
Income (Loss) Before Income Taxes	(209,139)	359,927
Credit for Income Taxes	(113,046)	(318,381)
Net Income (Loss)	$ (96,093)	$ 678,308

Wellsboro Electric Company
Statements of Stockholders' Equity
Years Ended December 31, 2024 and 2023

	Preferred Stock		Common Stock	
	Shares	**Amount**	**Shares**	**Amount**
Balance, January 1, 2023	1,300	$ 130,200	1,055.5	$ 112,300
Redemption of preferred stock	(42)	(4,200)	-	-
Dividends on preferred stock	-	-	-	-
Dividends on common stock	-	-	-	-
Net income	-	-	-	-
Balance, December 31, 2023	1,258	126,000	1,055.5	112,300
Redemption of preferred stock	(2)	(200)	-	-
Dividends on preferred stock	-	-	-	-
Dividends on common stock	-	-	-	-
Net loss	-	-	-	-
Balance, December 31, 2024	1,256	$ 125,800	1,055.5	$ 112,300

See Notes to Financial Statements

Treasury Stock		Additional		
Common Shares	Amount	Paid-in Capital	Retained Earnings	Total
67.5	$ (159,250)	$ 127,846	$ 4,572,900	$ 4,783,996
-	-	-	-	(4,200)
-	-	-	(5,084)	(5,084)
-	-	-	(45,500)	(45,500)
-	-	-	678,308	678,308
67.5	(159,250)	127,846	5,200,624	5,407,520
-	-	-	-	(200)
-	-	-	(5,032)	(5,032)
-	-	-	(48,700)	(48,700)
-	-	-	(96,093)	(96,093)
67.5	$ (159,250)	$ 127,846	$ 5,050,799	$ 5,257,495

Wellsboro Electric Company
Statements of Cash Flows
Years Ended December 31, 2024 and 2023

	2024	2023
Operating Activities		
Net income (loss)	$ (96,093)	$ 678,308
Items not requiring (providing) cash		
Depreciation and amortization	1,507,274	1,357,134
Deferred income taxes	(358,000)	(380,300)
Loss on disposal of utility plant and nonutility property	81,514	164,327
Provision for credit losses on accounts receivable	(7,859)	(15,189)
Changes in		
Accounts receivable	55,601	419,595
Inventories	86,057	107,224
Regulatory assets and liabilities	(39,594)	24,971
Prepaid expenses and other	(6,326)	(5,294)
Accounts payable, accrued expenses and other	25,835	327,587
Due for purchased electricity	(3,076)	(374,382)
Accrued postretirement cost	(21,190)	(63,441)
Deferred compensation	(49,441)	(48,222)
Prepaid taxes, net	26,792	(249,878)
Customer deposits	31,270	7,440
Under collected power costs	(53,535)	215,510
Net Cash Provided by Operating Activities	1,179,229	2,165,390
Investing Activity		
Additions to utility plant and nonutility property	(6,366,626)	(5,223,322)
Net Cash Used in Investing Activity	(6,366,626)	(5,223,322)
Financing Activities		
Principal payments on finance lease liabilities	(137,479)	(108,464)
Borrowings under line of credit agreement	3,700,000	-
Repayments under line of credit agreement	(3,000,000)	(150,000)
Proceeds from issuance of long-term debt	4,000,000	3,000,000
Principal payments on long-term debt	(650,282)	(828,701)
Dividends paid	(53,732)	(50,584)
Redemption of preferred stock	(200)	(4,200)
Net Cash Provided by Financing Activities	3,858,307	1,858,051
Decrease in Cash and Cash Equivalents	(1,329,090)	(1,199,881)
Cash and Cash Equivalents, Beginning of Year	1,532,425	2,732,306
Cash and Cash Equivalents, End of Year	$ 203,335	$ 1,532,425
Supplemental Cash Flows Information		
Interest paid	$ 859,424	$ 727,220
Right-of-use asset obtained in exchange for new finance lease liability	$ 66,390	$ 185,574
Income taxes paid	$ 10,000	$ 243,300
Income taxes refunded	$ 26,006	$ -

Wellsboro Electric Company
Notes to Financial Statements
December 31, 2024 and 2023

Note 1. Nature of Operations and Summary of Significant Accounting Policies

Nature of Operations

Wellsboro Electric Company ("Company"), also known as Wellsborough Electric Company, is a regulated public utility distributing electric service to customers in and around Wellsboro, Pennsylvania. C & T Enterprises, Inc. ("C&T") owns all of the outstanding common stock of the Company. The Company's operations are regulated by the Pennsylvania Public Utility Commission ("PUC"). The Company extends unsecured credit to its customers.

Basis of Accounting

The Company maintains its accounting records in accordance with the Federal Energy Regulatory Commission's ("FERC") uniform system of accounts for public utilities as modified and adopted by the PUC. The accompanying financial statements and the related notes have been prepared on the basis of U.S. generally accepted accounting principles ("GAAP").

In accordance with FERC guidelines, the Company also maintains its accounts in accordance with Codification Topic 980, *Regulated Operations*. On a regular basis, the Company reevaluates its application of accounting for regulated operations. The Company has determined that regulatory assets and liabilities should continue to be accounted for under provisions of Codification Topic 980 because it is reasonable to assume that the Company will continue to be able to charge and collect its cost of service-based rates.

Purchased Power

The Company purchases power under a default service plan that utilizes a third party generator to fulfill its requirements under the current plan. The plan, which was approved by the PUC, allows for full recovery of the cost of energy supply and all related costs, including legal and consulting fees and allows adjustments to rates to reflect current market conditions. Power costs can be different than what is recovered in base charges, resulting in over or under collected power costs.

Use of Estimates

The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates. Significant estimates include unbilled revenues, depreciation and postretirement benefits.

Cash and Cash Equivalents

The Company considers all liquid investments with original maturities of three months or less to be cash equivalents. At December 31, 2024 and 2023, cash equivalents consisted primarily of a daily investment fund account.

At December 31, 2024, the Company's cash accounts did not exceed federally insured limits.

Accounts Receivable

Accounts receivable include billed and unbilled amounts for services provided to customers for which the Company has an unconditional right to payment. The Company provides an allowance for credit losses, which is based upon a review of outstanding receivables, historical collection information and existing economic conditions adjusted for current conditions and reasonable and supportable factors.

Accounts receivable are generally due within 20 days after the date of the billing. Accounts that are unpaid after the due date bear interest at 1.50% per month. Accounts past due more than 30 days are considered delinquent. Interest continues to accrue on delinquent accounts until the account is no longer classified as delinquent.

Delinquent receivables are written off based on individual credit evaluation and specific circumstances of the customer.

During the years ended December 31, 2024 and 2023, there was no credit loss expense related to doubtful accounts receivable, where collectability is not reasonably assured.

Inventories

Inventories consist of materials and supplies and are stated at the lower of cost or net realizable value. Cost is determined based on average cost.

Utility Plant

Utility plant is carried at cost. Additions to utility plant and replacements of property are capitalized at cost. Retirements of electric plant or replacements are removed from electric plant accounts at cost and these costs plus cost of removal less salvage are charged to accumulated depreciation. Assets under finance lease obligations are amortized over the shorter of the lease term or respective estimated useful lives. Depreciation of utility plant is provided over the estimated useful life of the respective assets on a straight line basis as follows:

Utility Plant	Years
Distribution plant	10-40
General plant	5-40
Vehicles	5

Maintenance and repairs of property and replacements are charged to expense.

Nonutility Property

Nonutility property consists of land and other depreciable property not currently used for utility purposes.

Impairment of Long-Lived Assets

The Company reviews the carrying amount of an asset for possible impairment whenever events or changes in circumstances indicate that such amounts may not be recoverable. If a long-lived asset is tested for recoverability and the undiscounted estimated future cash flows expected to result from the use and eventual disposition of the asset is less than the carrying amount of the asset, the asset cost is adjusted to fair value and an impairment loss is recognized as the amount by which the carrying amount of a long-lived asset exceeds its fair value. No asset impairment was recognized during the years ended December 31, 2024 and 2023.

Deferred Compensation

As described in Note 11, the amount of expense accrued for deferred compensation is based on the present value of the total amount payable under the agreement.

Income Taxes

The Company is included in the consolidated federal income tax return filed by C&T. The Company files its own tax return in Pennsylvania. The Company's federal income tax expense is computed using the separate return method for intercorporate tax allocation.

The Company accounts for income taxes in accordance with income tax accounting guidance (Financial Accounting Standards Board ("FASB") Accounting Standards Codification ("ASC") 740, *Income Taxes*). The income tax accounting guidance results in two components of income tax expense: current and deferred. Current income tax expense reflects taxes to be paid or refunded for the current period by applying the provisions of the enacted tax law to the taxable income or excess of deductions over revenues. The Company determines deferred

income taxes using the liability (or balance sheet) method. Under this method, the net deferred tax asset or liability is based on the tax effects of the differences between the book and tax bases of assets and liabilities, and enacted changes in tax rates and laws are recognized in the period in which they occur. Deferred income tax expense results from changes in deferred tax assets and liabilities between periods. Deferred tax assets are reduced by a valuation allowance if, based on the weight of evidence available, it is more likely than not that some portion or all of a deferred tax asset will not be realized.

Tax positions are recognized if it is more likely than not, based on the technical merits, that the tax position will be realized or sustained upon examination. The term “more likely than not” means a likelihood of more than 50%; the terms examined and upon examination also include resolution of the related appeals or litigation processes, if any. A tax position that meets the more likely than not recognition threshold is initially and subsequently measured as the largest amount of tax benefit that has a greater than 50% likelihood of being realized upon settlement with a taxing authority that has full knowledge of all relevant information. The determination of whether or not a tax position has met the more likely than not recognition threshold considers the facts, circumstances and information available at the reporting date and is subject to the management’s judgment.

The Company recognizes interest and penalties on income taxes as a component of income tax expense.

Regulatory Matters

The Company is subject to the authoritative accounting guidance applicable to rate-regulated organizations. The Pennsylvania PUC has full authority to establish electric rates. Certain items collected in rates have been recorded as regulatory liabilities. These amounts will be recognized as revenue in future periods as costs for which the amounts have been collected are incurred, or when authorized by the Pennsylvania PUC. Certain expenses have been recorded as regulatory assets, and management believes these amounts are probable of future rate recovery.

Revenue Recognition

Revenues from the sale of electricity are recognized as electricity is delivered to customers. Revenues also include amounts receivable from or payable to customers through purchased power clauses, which are adjusted semi-annually.

Costs that are recoverable or refundable in future periods through purchase power recovery are deferred. Costs that are refundable or recoverable in future periods through purchased power recovery rates are subject to audit and approval by the appropriate regulatory body. Changes to the related asset or liability amounts that result from these audits are recorded as a charge to current operations.

The amount and timing of revenue recognition varies based on the nature of the goods or services provided and the terms and conditions of the customer contract. Unbilled revenues of $667,515 and $483,780 at December 31, 2024 and 2023, respectively, represent amounts delivered through December 31 and not billed to the customers until the following month. Customer deposits of $195,713 and $164,443 at December 31, 2024 and 2023, respectively, represent amounts received in advance of services provided. See Note 14 for additional information about the Company’s revenue.

For significant financing components, the Company elected a practical expedient, which allows an entity to recognize the promised amount of consideration without adjusting for the time value of money if the contract has a duration of one year or less, or if the reason the contract extended beyond one year is because the timing of delivery of the product is at the customer’s discretion. As the Company’s contracts are typically less than one year in length and do not have significant financing components, the Company does not present revenue on a present value basis.

Leases

The Company determines if an arrangement is a lease or contains a lease at inception. Leases result in the recognition of right-of-use (ROU) assets and lease liabilities on the balance sheets. ROU assets represent the right to use an underlying asset for the lease term, and lease liabilities represent the obligation to make lease payments arising from the lease, measured on a discounted basis. The Company determines lease classification as operating or finance at the lease commencement date. The ROU asset for finance leases are included in utility plant in our balance sheets.

At lease commencement, the lease liability is measured at the present value of the lease payments over the lease term. The ROU asset equals the lease liability adjusted for any initial direct costs, prepaid or deferred rent, and lease incentives. The Company has made a policy election to use a risk-free rate (the rate of a zero-coupon U.S. Treasury instrument) for the initial and subsequent measurement of all lease liabilities. The risk-free rate is determined using a period comparable with the lease term.

The lease term may include options to extend or to terminate the lease that the Company is reasonably certain to exercise. Lease expense is generally recognized on a straight-line basis over the lease term.

The Company has elected not to record leases with an initial term of 12 months or less on the balance sheets. Lease expense on such leases is recognized on a straight-line basis over the lease term.

Treasury Stock

Common stock shares repurchased are recorded at cost. Cost of shares retired or reissued is determined using the first-in, first-out method.

Taxes Collected from Customers and Remitted to Governmental Authorities

Sales and gross receipts taxes collected from customers and remitted to governmental authorities are presented in the accompanying statements of income on a net basis.

Note 2. Leases

Nature of Leases

The Company has the following lease arrangements:

Finance Leases

These leases mainly consist of vehicles for the use of the Company. Termination of the leases generally are prohibited unless there is a violation under the lease agreement.

All Leases

The Company has no material related-party leases. The Company’s lease agreements do not contain any material residual value guarantees or material restrictive covenants.

Quantitative Disclosures

The lease cost and other required information for the years ended December 31, 2024 and 2023, are:

	2024	2023
Lease cost		
Finance lease cost		
Amortization of right-of-use asset	$ 93,050	$ 109,180
Interest on lease liabilities	25,420	15,650
Short-term lease cost	36,561	33,159
Total lease cost	$ 155,031	$ 157,989
Other information		
Cash paid for amounts included in the measurement of lease liabilities		
Financing cash flows from finance leases	$ 137,479	$ 108,464
Weighted-average remaining lease term		
Finance leases	4.0 years	4.0 years
Weighted-average discount rate		
Finance leases	1.74%	2.13%

See Note 7 for future minimum lease payments and reconciliation to the balance sheet at December 31, 2024.

Note 3. Utility Plant

Utility plant consists of the following at December 31:

	2024	2023
Electric plant in service		
Distribution plant	$ 31,648,701	$ 29,731,485
General plant	9,453,235	6,298,889
	41,101,936	36,030,374
Construction work-in-progress	27,017	54,982
	41,128,953	36,085,356
Accumulated depreciation	(15,226,786)	(15,048,529)
	$ 25,902,167	$ 21,036,827

Note 4. Regulatory Assets and Liability

Regulatory assets consist of the following at December 31:

	2024	2023	Amortization Period
Default service plan	$ 32,362	$ 25,397	4 years
Other regulatory assets	7,783	6,077	3 years
	$ 40,145	$ 31,474	

For the years ended December 31, 2024 and 2023, the Company recorded a regulatory liability of $230,379 and $243,375, respectively, for other postretirement benefits that resulted from unrecognized gains. The Company expects to recover the deferred other postretirement benefits consistent with the anticipated income recognition of other postretirement income.

Amortization expense was $17,927 and $54,149 for the years ended December 31, 2024 and 2023, respectively.

Note 5. Nonutility Property

Nonutility property consists of the following at December 31:

	2024	2023
Land	$ 51,909	$ 51,909
Buildings and improvements	154,174	154,174
	206,083	206,083
Accumulated depreciation	(62,040)	(58,855)
	$ 144,043	$ 147,228

Note 6. Line of Credit

The Company has a $3,000,000 revolving line of credit with C&T payable on demand. At December 31, 2024, there was $700,000 borrowed against this line. At December 31, 2023, there were no borrowings against this line. Interest varies based on the CoBank quoted variable rate. The rate was 6.39% and 7.41% on December 31, 2024 and 2023, respectively, and is payable monthly.

While the line of credit above is due on demand, the Company utilized the financing for long-term operating purposes and does not have liquid funds available to repay the balance. The borrowings are available as a result of a line of credit agreement that C&T has with a third party, which is due in July 2026. C&T has no intentions of calling the debt before July 2026.

Wellsboro Electric Company
Notes to Financial Statements
December 31, 2024 and 2023

Note 7. Long-Term Debt and Finance Lease Liabilities

	2024	2023
Notes payable, C&T, payable in quarterly installments of approximately $80,000 including interest through September 2038; interest at 2.76% to 4.88%; collateralized by substantially all Company assets	$ 3,269,885	$ 3,440,823
Note payable, C&T, quarterly principal and interest payments of approximately $22,000; interest at 2.37%; collateralized by substantially all Company assets; due December 2028	280,213	346,225
Note payable, C&T, payable in quarterly installments of approximately $29,000 including interest through September 2031; interest at 2.635% to 4.63%; collateralized by substantially all Company assets	615,703	695,977
Note payable, C&T, quarterly principal and interest payments of approximately $22,000; interest at 3.575%; collateralized by substantially all Company assets; due December 2034	675,020	730,233
Note payable, C&T, quarterly principal and interest payments of approximately $36,000; interest at 4.175% to 4.80%; collateralized by substantially all Company assets; due June 2035	1,204,597	1,292,609
Note payable, C&T, quarterly principal and interest payments of $15,931; interest at 3.925%; collateralized by substantially all Company assets; due December 2041	787,765	819,781
Note payable, C&T, quarterly principal and interest payments of $17,075; interest at 4.175%; collateralized by substantially all Company assets; due December 2041	828,462	861,312
Note payable, C&T, quarterly principal and interest payments of $26,317; interest at 3.26%; collateralized by substantially all Company assets; due June 2050	1,818,139	1,863,214
Notes payable, C&T, quarterly principal and interest payments of $53,642; interest at 5.865% to 6.00%; collateralized by substantially all Company assets; due October 2052 through March 2053	5,862,965	5,942,857
Note payable, C&T, quarterly principal and interest payments of $66,095; interest at 5.18%; collateralized by substantially all Company assets; due December 2054	4,000,000	-
Finance lease liabilities for equipment, requiring monthly principal and interest payments ranging from $1,707 to $3,661, collateralized by leased equipment, payments due in varying amounts through December 2030	478,758	549,847
	19,821,507	16,542,878
Less current maturities	994,288	740,160
	$ 18,827,219	$ 15,802,718

Aggregate annual maturities of long-term debt and payments on finance lease liabilities at December 31, 2024, are:

	Long-Term Debt	Finance Lease Liabilities
2025	$ 865,074	$ 139,518
2026	902,292	129,400
2027	941,209	114,658
2028	981,908	70,731
2029	950,182	51,059
Thereafter	14,702,084	32,890
	$ 19,342,749	538,256
Less amount representing interest		59,498
Present value of future minimum lease payments		$ 478,758

Transportation equipment under finance lease liabilities is as follows:

	2024	2023
Transportation equipment	$ 1,016,222	$ 949,832
Accumulated depreciation	(561,754)	(432,235)
	$ 454,468	$ 517,597

C&T has a Master Letter of Credit agreement with National Cooperative Services Corporation. This Letter of Credit is for $7,000,000 and expires October 2029. The Company has the ability to post letters of credit with wholesale electric suppliers under the terms of this agreement. As of December 31, 2024 and 2023, the Company had no outstanding letters of credit.

Note 8. Income Taxes

The credit for income taxes includes these components:

	2024	2023
Taxes currently payable	$ 244,954	$ 61,919
Deferred income taxes	(358,000)	(380,300)
Income tax benefit	$ (113,046)	$ (318,381)

A reconciliation of income tax expense (benefit) at the statutory rate to the Company's actual income tax benefit is shown below:

	2024	2023
Computed at the statutory rate (21%)	$ (43,919)	$ 75,585
Increase (decrease) resulting from		
State income rates	(55,584)	4,608
Utilization of federal net operating losses	-	(380,300)
Other	(13,543)	(18,274)
Actual tax benefit	$ (113,046)	$ (318,381)

The tax effects of temporary differences related to deferred taxes shown on the balance sheets were:

	2024	2023
Deferred tax assets		
Allowance for credit losses	$ 3,400	$ 5,600
Post retirement benefits	58,000	64,700
Net operating loss carryforwards	-	12,300
Deferred compensation	-	13,700
Other	103,300	103,900
	164,700	200,200
Deferred tax liabilities		
Depreciation	(1,324,100)	(1,722,600)
Other	(13,300)	(8,300)
	(1,337,400)	(1,730,900)
Net deferred tax liability	$ (1,172,700)	$ (1,530,700)

At December 31, 2024 and 2023, the Company had no allocation of C&T consolidated unused federal operating loss carryforwards.

Note 9. Pension, Profit-Sharing and Postretirement Plans

Multiemployer Pension Plans

C&T is a member of the National Rural Electric Cooperative Association ("NRECA") Retirement Security Plan ("RS Plan"), a defined benefit pension plan qualified under Section 401 and tax-exempt under Section 501(a) of the Internal Revenue Code. It is a multiemployer plan under the accounting standards. The Plan sponsor's Employer Identification Number is 53-0116145 and the Plan Number is 333.

A unique characteristic of a multiemployer plan compared to a single employer plan is that all plan assets are available to pay benefits of any plan participant. Separate asset accounts are not maintained for participating employers. This means that assets contributed by one employer may be used to provide benefits to employees of other participating employers.

C&T contributions to the RS Plan in 2024 and 2023 represented less than 5% of the total contributions made to the plan by all participating employers. C&T made contributions to the plan of $3,497,266 and $3,441,415 for the years ended December 31, 2024 and 2023, respectively. The Company reimbursed C&T $271,079 and $259,724 for its share of the contributions for the years ended December 31, 2024 and 2023, respectively. There have been no significant changes affecting the comparability of the 2024 and 2023 contributions.

In the RS Plan, a "zone status" determination is not required, and therefore not determined, under the *Pension Protection Act* ("PPA") of 2006. In addition, the accumulated benefit obligations and plan assets are not determined or allocated separately by individual employer. In total, the RS Plan was over 80% funded on January 1, 2024 and 2023, based on the PPA funding target and PPA actuarial value of assets on those dates.

Because the provisions of the PPA do not apply to the RS Plan, funding improvement plans and surcharges are not applicable. Future contribution requirements are determined each year as a part of the actuarial valuation of the plan and may change as a result of plan experience.

C&T is also a member of the NRECA SelectRE Pension Plan. C&T makes a matching contribution of 200% of the employees' contributions up to 2.5% of compensation. The Company reimbursed C&T $51,725 and $43,729 for its share of contributions for the years ended December 31, 2024 and 2023, respectively.

Profit Sharing Plan

The Company has a profit sharing plan that covers all full-time employees who have attained one year of service. Contributions are discretionary and are allocated based upon eligible compensation. A vesting schedule provides for full vesting after six years of service while in the Plan. The Company made a discretionary profit-sharing plan contribution to the Plan of $89,000 and $75,000 for the years ended December 31, 2024 and 2023, respectively.

Other Postretirement Plans

The Company also has a defined contribution retirement plan that covers all full-time employees covered under a collective bargaining agreement who have attained the age of 18 years and have one year of service. Employees are permitted to make tax deferred contributions of up to 15% of eligible compensation. The Company makes a matching contribution to the Plan up to 5% of a participant's eligible compensation. The Company contributed $38,489, and $36,416 to the Plan for the years ended December 31, 2024 and 2023, respectively.

C&T has a postretirement health care plan covering substantially all employees. The plan is unfunded. The estimated costs that will be paid after retirement are generally being accrued over the employees' active service periods to the dates they are fully eligible for benefits. The Company expects to contribute $9,000 to the Plan in 2025. The following table sets forth the plan's funded status and the amounts of accrued benefit cost of the C&T plan and the Company's allocation based on an actuarial valuation as of December 31, 2024 and 2023.

	2024	2023
C&T's benefit obligation	$ 5,587,931	$ 5,725,208
Company's allocation of benefit obligation	$ 212,352	$ 233,542
C&T's accrued benefit cost	$ 5,587,931	$ 5,725,208
Company's allocation of accrued benefit cost	$ 212,352	$ 233,542
Amounts recognized in the Company's balance sheets		
Current liability, included in accrued expenses	$ 26,773	$ 43,364
Non-current liability	185,579	190,178
	$ 212,352	$ 233,542
C&T's benefit expense	$ 472,065	$ 480,148
Company's allocation of benefit expense	$ 9,188	$ 10,867

The Company uses a December 31 measurement date for the plans. For measurement purposes, a 6.50% annual rate of increase in the per capita cost of covered health care benefits was assumed in 2024. The rate was assumed to decrease gradually to 4.75% in 2031 and remain at that level thereafter.

The benefit obligation was calculated assuming a weighted average discount rate of 5.15% and 5.10% in 2024 and 2023, respectively.

The amount of net gain and net prior service cost expected to be recognized by the Company during 2025 is $12,385 and $-0-, respectively.

Benefits expected to be paid by the Company in each of the next five years and in the aggregate for the five years thereafter are as follows:

2025	$	26,773
2026	$	34,678
2027	$	25,401
2028	$	19,611
2029	$	24,382
2030-2034	$	14,371

Because the Company is subject to regulation in the states in which it operates, it is required to maintain its accounts in accordance with the regulatory authority's rules and regulations, which may differ from other authoritative accounting pronouncements. In those instances, the Company follows the guidance of accounting for regulated operations. Based on prior regulatory practice, and in accordance with the related guidance, the Company recorded an unfunded postretirement obligation, which otherwise would be recognized as other comprehensive income, as a regulatory asset, and expects to recover those costs in rates charged to customers.

Note 10. Related Party Transactions

The Company has a contract for services with C&T to purchase all employee services. The contract automatically renews annually unless terminated by either party.

The Company has a lease agreement with C&T for space in the primary office building, the contract renews monthly unless terminated by either party. The Company also had a lease agreement with C&T for space in the secondary office building, this contract was terminated November 2023.

In the ordinary course of business, the Company's activities involve significant transactions with C&T. The activity between the Company and C&T for the years ended December 31, 2024 and 2023, and the effected account balances at December 31, 2024 and 2023, are as follows:

	2024		2023	
Allocation of overhead recorded as operating expense	$	442,449	$	404,670
Other costs in accounts receivable - other	$	276,900	$	276,900
Accounts payable - related party	$	133,216	$	136,794
Accrued vacation liability in accrued expenses	$	147,991	$	131,852
Payroll costs paid in advance and included in advances, affiliate	$	49,000	$	49,000
Interest expense	$	859,424	$	727,220
Acquisition debt expense	$	361,458	$	124,686
Rental income in miscellaneous income	$	-	$	33,000

The Company paid C&T $1,037,111 and $984,657 for payroll and $450,012 and $397,354 for benefits in 2024 and 2023, respectively.

Note 11. Deferred Compensation

The Company had a deferred compensation agreement with a certain former officer. The total amount payable under the agreement is $152,074, to be paid in three equal annual installments of $50,691, starting in January 2022 through January 2024. As of December 31, 2024, installment payments of $152,074 have been paid to the former officer.

At December 31, 2024, there was no deferred compensation liability. At December 31, 2023, the present value of the 2024 payment is $49,411 which is included in current liabilities.

Note 12. Commitments and Contingencies

The Company has guaranteed payments on notes payable that are obligations of C&T. At December 31, 2024, the amounts outstanding on these obligations are $23,092,250, of which $19,342,749 is recorded by the Company, see Note 7. These obligations are being repaid in quarterly payments of principal and interest through 2054. The amounts outstanding that are not recorded by the Company are being repaid through acquisition debt expense. The Company would be required to perform under this guarantee if C&T were to default under the notes payable and the bank were to demand the Company's performance.

Note 13. Significant Concentration

Accounting principles generally accepted in the United States of America require disclosure of current vulnerabilities due to certain concentrations.

Labor Agreement

Approximately 50% of the Company's employees are covered by a collective bargaining agreement, which expires December 31, 2026.

Note 14. Revenue from Contracts with Customers

Performance Obligations

The Company's revenues are derived primarily from the sale of electric power to customers. Customers consist of commercial, industrial and residential accounts within dedicated territories in and around Wellsboro, Pennsylvania.

Rates charged for electric power sales to customers are established by the Pennsylvania PUC. The Company provides energy and capacity to customers as one stand-ready performance obligation. Electric power revenue is recognized by the Company upon transfer of control of promised services to customers in an amount that reflects the consideration expected to be received in exchange for those services.

The Company transfers control of the electric power to customers at each customer's meter point and the customers simultaneously receive and consume the benefits of the energy provided. Electric power provided to customers is accounted for as a series of performance obligations. Progress towards completion is measured using the output method [kilowatt hour (kwh) received by the customer], meter readings are taken at the end of each month for billing purposes, the quantity of energy transferred is determined after the meter readings.

Payments from customers are received in accordance with each customer's contract, which is ordinarily 20 days from the invoice date.

Revenue associated with the electric power performance obligation to customers are recorded as sales of electric energy and capacity to customers in our accompanying statements of income.

The Company has determined that the nature, amount, timing and uncertainty of revenue and cash flows are primarily affected by factors that impact demand.

Contract Balances

The following table provides information about the Company's accounts receivable and customer deposits from contracts with customers:

	2024	2023
Accounts receivable - customers, beginning of year	$ 1,380,833	$ 1,508,966
Accounts receivable - customers, end of year	$ 1,186,224	$ 1,380,833
Unbilled revenues, beginning of year	$ 483,780	$ 752,184
Unbilled revenues, end of year	$ 667,515	$ 483,780
Customer deposits, beginning of year	$ 164,443	$ 157,003
Customer deposits, end of year	$ 195,713	$ 164,443

Note 15. Subsequent Events

Subsequent events have been evaluated through March 12, 2025, which is the date the financial statements were available to be issued.

Supplementary Information

Wellsboro Electric Company
Utility Plant and Accumulated Depreciation
Year Ended December 31, 2024

Acct. No.	Account	Utility Plant: Cost January 1, 2024	Additions	Retirements	Contributions in Aid to Construction	Cost December 31, 2024	Accumulated Depreciation: Balance January 1, 2024	Depr. Rate (%)	Credits Representing: Depreciation Accruals	Credits Representing: Salvage	Debits Representing: Property Retired	Debits Representing: Cost of Removal	Balance December 31, 2024
	Distribution, plant												
360	Land and land rights	$ 178,334	$ -	$ -	$ -	$ 178,334	$ -	0.00	$ -	$ -	$ -	$ -	$ -
361	Structures and improvements	-	-	-	-	-	-	4.08	-	-	-	-	-
362	Station equipment	3,979,535	13,265	-	-	3,992,800	3,245,999	6.88	141,847	-	-	-	3,387,846
364	Poles, towers and fixtures	12,456,164	1,918,214	109,492	808,299	13,456,587	3,885,628	3.50	440,594	5,611	109,492	113,107	4,109,234
365	Overhead conductors and devices	5,529,274	1,721,121	58,783	1,107,640	6,083,972	1,707,606	3.97	221,459	3,674	58,783	62,882	1,811,074
366	Underground conduits	26,899	-	-	-	26,899	10,761	3.15	849	-	-	-	11,610
367	Underground conductors and devices	1,008,032	19,299	-	15,781	1,011,550	634,193	4.36	43,964	-	-	-	678,157
368.1	Line transformers	2,923,411	285,923	11,002	-	3,198,332	1,388,859	3.52	102,104	118	11,002	12,960	1,467,119
369	Services	849,838	12,862	2,831	4,560	855,309	788,699	6.00	9,466	187	2,831	2,741	792,780
369.1	Underground services	1,300,817	76,122	1,177	31,212	1,344,550	464,366	2.48	32,826	16	1,177	27	496,004
370.1	Meters	986,943	27,460	2,922	-	1,011,481	556,160	7.70	75,858	-	2,922	-	629,096
371	Installation on customer premises	373,328	4,992	8,701	2	369,617	(9,128)	10.37	38,453	1,627	8,701	6,514	15,737
373	Street lighting and signal systems	118,915	419	62	-	119,272	(71,623)	2.40	2,861	-	62	87	(68,911)
	General plant												
390.1	Structures and improvements, office	2,486,413	3,722,470	544,972	-	5,663,911	507,553	4.58	92,336	-	485,119	-	114,770
390.2	Structures and improvements, other	884,002	-	-	-	884,002	31,957	5.20	45,708	-	-	-	77,665
391	Office furniture and equipment	601,624	297,517	124,652	-	774,489	378,038	19.49	69,221	-	122,201	-	325,058
392	Transportation equipment	1,646,618	66,390	180,998	-	1,532,010	1,035,960	Various	155,341	-	180,998	-	1,010,303
394	Tools, shop and garage equipment	90,042	-	-	-	90,042	29,100	6.17	4,976	-	-	-	34,076
395	Laboratory equipment	96,079	-	80,650	-	15,429	90,397	2.66	1,544	-	80,650	-	11,291
396	Power operated equipment	98,149	72,184	80,518	-	89,815	59,514	3.11	2,845	-	61,308	-	1,051
397	Communications equipment	110,323	7,578	-	-	117,901	29,968	7.71	8,336	-	-	-	38,304
398	Miscellaneous equipment	-	-	-	-	-	(64)	0.00	-	-	-	-	(64)
301	Intangible plant, organization	1,046	-	-	-	1,046	-	0.00	-	-	-	-	-
303	Intangible asset - EDI	284,588	-	-	-	284,588	284,586	14.28	-	-	-	-	284,586
		$ 36,030,374	$ 8,245,816	$ 1,206,760	$ 1,967,494	$ 41,101,936	$ 15,048,529		$ 1,490,588	$ 11,233	$ 1,125,246	$ 198,318	$ 15,226,786
	Construction work-in-process	54,982	(27,965) (N)	-	-	27,017			155,341	Less charged to clearing			
		$ 36,085,356	$ 8,217,851	$ 1,206,760	$ 1,967,494	$ 41,128,953			$ 1,335,247	Total depreciation			

(N) Net decrease

Wellsboro Electric Company
Prepaid Taxes, Net
December 31, 2024 and 2023

	2024	2023
State gross receipts tax	$ 124,940	$ (100,575)
State public realty tax	6,000	2,583
State capital stock and corporate loans taxes	13,116	13,116
Federal income tax	(156,426)	90,833
State income tax	120,114	133,815
State sales tax	1,119	(4,117)
	$ 108,863	$ 135,655

Wellsboro Electric Company
Operating Revenues and Taxes, Other Than Income
Years Ended December 31, 2024 and 2023

	2024	2023
Operating Revenues		
Residential sales	$ 6,987,418	$ 8,117,407
Commercial and industrial sales	5,815,205	6,260,544
Public street and highway lighting sales	19,202	21,836
Sales for resale	18,070	19,546
Customers' forfeited discounts	28,860	41,090
Rent from electric property	266,738	205,307
Other electric revenues	22,899	46,809
	$ 13,158,392	$ 14,712,539
Taxes, Other Than Income		
State gross receipts	$ 781,072	$ 812,368
State use tax	837	908
Lease tax	(10,663)	3,743
State public utility realty tax	43,311	40,764
	$ 814,557	$ 857,783

Wellsboro Electric Company
Distribution, Operation; Distribution, Maintenance;
Customer Accounts; Sales Expense, Public Relations
and General and Administrative Expenses
Years Ended December 31, 2024 and 2023

	2024	2023	Increase (Decrease)	% Change
Distribution, Operation Expenses				
Supervising and engineering	$ 8,121	$ -	8,121	100.00%
Overhead lines expense	769	685	84	12.26%
Street lighting and signal systems expense	146	675	(529)	100.00%
Meter expenses	36,984	33,644	3,340	9.93%
Miscellaneous	174,151	170,671	3,480	2.04%
Rents	32,950	30,717	2,233	7.27%
	$ 253,121	$ 236,392	$ 16,729	7.08%
Distribution, Maintenance Expenses				
Supervising and engineering	$ 101,529	$ 85,711	$ 15,818	18.46%
Station equipment	3,210	5,697	(2,487)	-43.65%
Overhead lines	869,787	836,768	33,019	3.95%
Underground lines	30,206	28,436	1,770	6.22%
Line transformers	14,532	5,678	8,854	155.94%
Street lighting and signal system	1,612	2,991	(1,379)	-46.10%
Meters	64,506	75,467	(10,961)	-14.52%
	$ 1,085,382	$ 1,040,748	$ 44,634	4.29%
Customer Accounts Expenses				
Meter reading expense	$ 21,775	$ 19,809	$ 1,966	9.92%
Customer records and collection expense	903,980	873,245	30,735	3.52%
	$ 925,755	$ 893,054	$ 32,701	3.66%
Sales Expense, Public Relations	$ 2,991	$ 2,052	939	45.76%
General and Administrative Expenses				
Salaries	$ 757,901	$ 652,640	$ 105,261	16.13%
Office expense	178,754	145,066	33,688	23.22%
Outside services employed	137,115	87,889	49,226	56.01%
Property insurance	53,098	51,268	1,830	3.57%
Regulatory commission expenses	42,985	68,366	(25,381)	-37.13%
Miscellaneous general expenses, net	84,584	108,939	(24,355)	-22.36%
Rents	3,611	2,442	1,169	47.87%
Maintenance of general plant	72,186	112,581	(40,395)	-35.88%
Cost allocated to power purchased	(65,853)	(83,141)	17,288	-20.79%
	$ 1,264,381	$ 1,146,050	$ 118,331	10.33%

McNees Wallace & Nurick LLC
100 Pine Street
P.O. Box 1166
Harrisburg, PA 17108-1166

Adeolu A. Bakare
Direct Dial: 717.237.5290
Direct Fax: 717.260.1744
abakare@mcneeslaw.com

December 20, 2024

VIA ELECTRONIC FILING

Rosemary Chiavetta, Secretary
Pennsylvania Public Utility Commission
Commonwealth Keystone Building
400 North Street, 2nd Floor
Harrisburg, PA 17120

RE: Wellsboro Electric Company
Supplement No. 159 to Tariff Electric PA. P.U.C. No. 8 (State Tax Adjustment Surcharge Recalculation); Docket No. _____

Dear Secretary Chiavetta:

Attached for filing with the Commission is Wellsboro Electric Company's ("Wellsboro" or the "Company") Supplement No. 159 to Tariff Electric-Pa. P.U.C. No. 8 ("Supplement No. 159"). Supplement No. 159 reflects a recalculation of the State Tax Adjustment Surcharge ("STAS"). Supplement No. 159 contains an issued date of December 19, 2024, and an effective date of January 1, 2025. This complies with the ten (10) day notice period for STAS modifications specified on page 46 of Wellsboro's tariff.

This filing adjusts Wellsboro's STAS to refund a prior period overcollection and to reflect changes in the Corporate Net Income Tax and Utility Realty Tax. The documents supporting the Company's recalculation are set forth in Tab A, Attachments A, B, C, D, E, and F (computation of STAS for period January 1, 2025, through December 31, 2025). For completeness, a copy of proposed Supplement No. 159 is attached at Tab B. The supporting documents at Tab A demonstrate that Wellsboro's STAS rate will decrease from a surcredit of -0.0102% to a surcredit of -0.0438%, effective January 1, 2025. See Tab A.

If you have any questions regarding the documents, please feel free to contact the undersigned. Thank you.

Very truly yours,

Adeolu A. Bakare
MCNEES WALLACE & NURICK LLC
Counsel to Wellsboro Electric Company

AAB/leh
Enclosures
c: Certificate of Service
Erin Laudenslager, Bureau of Technical Utility Services (via E-mail)
Lori Burger, Bureau of Audits (via E-mail)

CERTIFICATE OF SERVICE

I hereby certify that I am this day serving a true copy of the foregoing document upon the participants listed below in accordance with the requirements of Section 1.54 (relating to service by a participant).

VIA E-MAIL

NazAarah Sabree
Small Business Advocate
Commonwealth of Pennsylvania
Office of Small Business Advocate
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555 Walnut Street, 1st Floor
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Allison C. Kaster, Esq.
Bureau of Investigation and Enforcement
Pennsylvania Public Utility Commission
Commonwealth Keystone Building
P. O. Box 3265
Harrisburg, PA 17105-3265
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Adeolu A. Bakare

Counsel to Wellsboro Electric Company

Dated this 20th day of December, 2024, in Harrisburg, Pennsylvania.

Wellsboro Electric Company

Supplement No. 159 to
Tariff Electric Pa. P.U.C. No. 8

WELLSBORO ELECTRIC COMPANY

General Tariff of

Rates, Rules and Regulations Governing

the Provision of Electric Service

in

The Borough of Wellsboro

and the Townships of Charleston,

Delmar and Middlebury, Tioga County, Commonwealth of Pennsylvania

Issued December 20, 2024

Effective January 1, 2025

Issued by: Byron Farnsworth, Jr., President and Chief Executive Officer
Wellsboro Electric Company
33 Austin Street
Wellsboro, PA 16901

NOTICE

THIS TARIFF MAKES {{CHANGES}} TO EXISTING RATES
See Page 2

Wellsboro Electric Company

Supplement No. 159 to
Tariff Electric Pa. P.U.C. No. 8
One-Hundred-Forty-Fourth Revised Page No. 2
Canceling One-Hundred-Forty-Third Revised Page No. 2

LIST OF CHANGES

Page 46:

Supplement No. 159 sets the Company's State Tax Adjustment Surcharge ("STAS") at -0.0438% effective on January 1, 2025. This recalculation is necessary to refund a prior period overcollection and to reflect changes to the Company's Corporate Net Income Tax and Utility Realty Tax.

Wellsboro Electric Company

Supplement No. 159 to
Tariff Electric Pa. P.U.C. No. 8
One-Hundred-Forty-Second Revised Page No. 3
Canceling One-Hundred-Forty-First Revised Page No. 3

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(C) Indicates Change

Wellsboro Electric Company

Supplement No. 159 to
Tariff Electric Pa. P.U.C. No. 8
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(C) Indicates Change

Wellsboro Electric Company

Supplement No. 159 to
Tariff Electric Pa. P.U.C. No. 8
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Canceling Thirty-Fourth Revised Page No. 46

RIDER A – STATE TAX ADJUSTMENT SURCHARGE

(Applicable to all rates except Service Schedule No. 8)

In addition to the charges provided in this tariff, a surcredit of -0.0438% will apply to all bills for service rendered on or after January 1, 2025. (D) (C)

The above surcharge will be recomputed, using the elements prescribed by the Pennsylvania Public Utility Commission.

(a) Whenever any of the tax rates used in the calculations of the surcharge are changed.

(b) Whenever the Company makes effective increased or decreased rates.

The above recalculations will be submitted to the Commission within 10 days after the occurrence of the event or date which occasion such re-computation. If the recomputed surcharge is less than the one in effect the Company will, and if the recomputed surcharge is more than the one then in effect the company may submit with such re-computation a Tariff or supplement to reflect such recomputed surcharge; the effective date of which shall be ten days after filing.

(D) Indicates Decrease (C) Indicates Change

WELLSBORO ELECTRIC COMPANY

Computation of State Tax Adjustment Surcredit
for the Period January 1, 2025 through December 31, 2025

			Amount	Attachment Number
1	Capital Stock Tax	$	-	
2	Corporate Net Income Tax	$	(28,406)	**F**
3	Utility Realty Tax	$	1,085	**A**
4	Gross Receipts Tax	$	-	
5	Total of Lines 1, 2, 3, and 4	$	(27,321)	
6	PURTA Surcharge Rate Adjustment	$	-	**B**
7	Revenue Neutral Reconciliation (RNR) Tax Adjustment	$	-	**C**
8	Total of Lines 5, 6, and 7	$	(27,321)	
9	Line 8 divided by complement of Gross Receipts Tax Rate (.941)	$	(29,034)	
10	STAS reconciliation for period January 1, 2024 through December 31, 2024	$	22,572	**D**
11	Total of Lines 9 and 10	$	(6,462)	
12	Gross Intrastate Operating Revenues derived from service under rates subject to the jurisdiction of the Pa. Public Utility Commission for the period January 1, 2023 through December 31, 2023 (Page 11)	$	14,743,214	**E**
13	Surcredit rate to be applied for the period January 1, 2025 through December 31, 2025 (Line 11 divided by Line 12)		-0.0438%	

ATTACHMENT A

WELLSBORO ELECTRIC COMPANY

Calculation of Surcredit Rate 1/01/25 - 12/31/25

Public Utility Realty Tax Assessment (PURTA)

1	7/31/2024 Notice of Determination Adjustments: State Tax Property Value at December 31, 2023	$ 1,819,024		
2	Pa. Public Utility Realty Tax (Based on applied rate of 23.7970 mills x Line 1)		$ 43,287	
3	8/1/2023 Notice of Determination Adjustments: State Tax Property Value at December 31, 2022	$ 1,699,052		
4	Pa. Public Utility Realty Tax (Based on applied rate of 24.8531 mills x Line 1)		$ 42,227	
5	2025 PURTA Adjustment (Line 2 minus Line 4)			$ 1,061

continued on page 2A

ATTACHMENT A

WELLSBORO ELECTRIC COMPANY

Calculation of Surcredit Rate 1/01/25 - 12/31/25

Public Utility Realty Tax Assessment (PURTA)

1	Continued from page 2 (Line 5)			$	1,061
	7/31/2024 Notice of Determination Adjustments:				
2	2019 PURTA				
	Liability Adjustment	$	3	$	3
3	2020 PURTA				
	Liability Adjustment	$	3	$	3
4	2021 PURTA				
	Liability Adjustment	$	3	$	3
5	2022 PURTA				
	Liability Adjustment	$	15	$	15
7	Total 2025 PURTA Adjustment (Lines 1 through 19)			$	1,085

ATTACHMENT B

WELLSBORO ELECTRIC COMPANY

Calculation of Surcredit Rate 1/01/25 - 12/31/25

Public Utility Realty Tax Assessment Surcharge

Tax Year Ending 2025

Projected taxable revenues for period January 1, 2025 to December 31, 2025 (Page 13)	$	15,636,525
PURTA surcharge rate as established by the Department of Revenue and published in the Pennsylvania Bulletin on September 21, 2024		0.0000
2025 PURTA Surcredit	$	-

ATTACHMENT C

WELLSBORO ELECTRIC COMPANY

Revenue Neutral Reconciliation (RNR) Tax Adjustment
Applicable to Gross Receipts Tax

Tax Year Ending 2025

Projected taxable revenues for Pa. gross receipts tax for period January 1, 2025 to December 31, 2025 (Page 13)	$	15,636,525
RNR tax rate adjustment as established by the Department of Revenue and published in the Pennsylvania Bulletin on Dec. 1, 2001		0.000
Projected increase in applicable 2025 gross receipts tax liability based on RNR tax rate adjustment	$	-

ATTACHMENT D

WELLSBORO ELECTRIC COMPANY

Reconciliation of State Tax Adjustment Surcredit
for the Period ending December 31, 2024

			Amount	Schedule Number
1	Capital Stock Tax	$	-	**1**
2	Corporate Net Income Tax	$	-	
3	Utility Realty Tax	$	520	**2**
4	Gross Receipts Tax	$	-	
5	Total of Items 1, 2, 3, and 4	$	520	
6	PURTA Surcharge Rate Adjustment	$	-	**3**
7	Revenue Neutral Reconciliation (RNR) Tax Adjustment	$	-	**4**
8	Total of Lines 5, 6, and 7	$	520	
9	Line 8 divided by complement of Gross Receipts Tax Rate (.941)	$	552	
10	STAS reconciliation for period Jan. 1, 2023 through December 31, 2023	$	20,740	
11	Total of Lines 9 and 10	$	21,292	
12	Total revenue collected/(refunded) from Jan. 1, 2024 through Dec. 31, 2024 (Page 10)	$	(1,279)	**5**
13	(Over)/Under Collection (Line 11 minus Line 12)	$	22,572	

ATTACHMENT D

WELLSBORO ELECTRIC COMPANY

Schedule 1

Reconciliation of State Tax Adjustment Surcredit
for the Period ending December 31, 2024

Capital Stock Tax @ .00 mills effective 1/1/17

1	Tax Base -- current settlement - year 2016 see attached page 2 of 2016 PA Corporate Tax Report		$ -
2	Tax Millage in basic rates (2017)	0.000000	
3	Tax Millage effective 1/1/18	0.000000	
4	Effective Rate Increase (Decrease) (Line 2 minus Line 3)		0.000000
5	Total Capital Stock/Franchise Tax Increase (Decrease) (Line 1 X Line 4)		$ -

ATTACHMENT D

WELLSBORO ELECTRIC COMPANY

Schedule 2

Reconciliation of State Tax Adjustment Surcharge
for the Period ending December 31, 2024

Public Utility Realty Tax Assessment (PURTA)

1	8/1/2023 Notice of Determination Adjustments: State Tax Property Value at December 31, 2022	$ 1,699,052		
2	Pa. Public Utility Realty Tax (Based on applied rate of 24.8531 mills x Line 1)		$ 42,227	
3	8/1/2022 Notice of Determination Adjustments: State Tax Property Value at December 31, 2021	$ 1,506,376		
4	Pa. Public Utility Realty Tax (Based on applied rate of 27.1851 mills x Line 1)		$ 40,951	
5	2024 PURTA Adjustment (Line 2 minus Line 4)			$ 1,276

continued on page 7A

ATTACHMENT D

WELLSBORO ELECTRIC COMPANY

Schedule 2

Public Utility Realty Tax Assessment (PURTA)

1	Continued from page 7 (Line 5)			$	1,276
	Notice of Determination Adjustments:	**8/1/2023**			
2	2018 PURTA				
	Liability Adjustment	$	(95)	$	(95)
3	2019 PURTA				
	Liability Adjustment	$	(88)	$	(88)
4	2020 PURTA				
	Liability Adjustment	$	(106)	$	(106)
5	2021 PURTA				
	Liability Adjustment	$	(467)	$	(467)
7	Total 2025 PURTA Adjustment (Lines 1 through 19)			$	520

ATTACHMENT D

WELLSBORO ELECTRIC COMPANY

Schedule 3

Reconciliation of State Tax Adjustment Surcredit
for the Period ending December 31, 2024

Public Utility Realty Tax Assessment Surcharge

Tax Year Ending 2024

Projected taxable revenues for period January 1, 2024 to December 31, 2024 (Page 12)	$	12,919,100
PURTA surcharge rate as established by the Department of Revenue and published in the Pennsylvania Bulletin on September 30, 2023		0.0000
2024 PURTA Surcharge	$	-

ATTACHMENT D

WELLSBORO ELECTRIC COMPANY

Schedule 4

Reconciliation of State Tax Adjustment Surcredit
for the Period ending December 31, 2024

Revenue Neutral Reconciliation (RNR) Tax Adjustment
Applicable to Gross Receipts Tax

Tax Year Ending 2024

1	Projected taxable revenues for Pa. gross receipts tax for period January 1, 2024 to December 31, 2024 (Page 12)	$	12,919,100
2	RNR tax rate adjustment as established by the Department of Revenue and published in the Pennsylvania Bulletin on Dec. 1, 2001		0.000
3	Projected increase in applicable 2024 gross receipts tax liability based on RNR tax rate adjustment	$	-

ATTACHMENT D

WELLSBORO ELECTRIC COMPANY

Schedule 5

STAS Revenue Collected/(Refunded)
for the Period ending December 31, 2024

Month		**Tax Surcharge**
January	$	(118)
February	$	(117)
March	$	(112)
April	$	(105)
May	$	(95)
June	$	(96)
July	$	(111)
August	$	(112)
September	$	(104)
October	$	(92)
November (estimate)	$	(109)
December (estimate)	$	(109)
Total STAS Collected/(Refunded)	$	(1,279)

ATTACHMENT E

WELLSBORO ELECTRIC COMPANY

OPERATING REVENUES

Revenue billed for 12 month audited period ending December 31, 2023

Residential	$	8,265,130		
Commercial & Industrial	$	6,374,476		
Public Street & Highway Lighting	$	21,836		
Sales for Resale	$	19,546		
Customer' Forfeited Discounts	$	41,090		
Total Gross Electric Revenue including Tax Surcharge *			$	14,722,078
Less: Tax Surcharge collected			$	(21,136)
Total Electric Revenue projected for application period January 1, 2025 through December 31, 2025			$	14,743,214

*Revenue does not include unbilled revenue.

WELLSBORO ELECTRIC COMPANY

Revenues from Service Billed Under Rates
for the Application Period January 1, 2024 to December 31, 2024

Month	MWh Sales	Base Rate Revenue*	Forfeited Discounts	Revenues
January	8,840	$ 1,189,359	$ 2,481	$ 1,191,840
February	8,667	$ 1,173,983	$ 3,353	$ 1,177,336
March	8,304	$ 1,119,739	$ 3,073	$ 1,122,812
April	7,959	$ 1,053,682	$ 2,403	$ 1,056,086
May	7,183	$ 954,906	$ 2,254	$ 957,159
June	7,787	$ 966,531	$ 1,849	$ 968,380
July	8,650	$ 1,125,966	$ 2,623	$ 1,128,588
August	8,674	$ 1,126,974	$ 2,247	$ 1,129,220
September	8,047	$ 1,051,241	$ 1,757	$ 1,052,999
October	7,076	$ 930,287	$ 2,849	$ 933,136
November (Projected)	8,194	$ 1,097,876	$ 2,895	$ 1,100,771
December (Projected)	8,194	$ 1,097,876	$ 2,895	$ 1,100,771
Totals	97,576	$ 12,888,421	$ 30,679	$ 12,919,100

*Revenue does not include unbilled revenue.

WELLSBORO ELECTRIC COMPANY

Projected Revenues from Service Billed Under Rates
for the Application Period January 1, 2025 to December 31, 2025

Month	MWh Sales		Base Rate Revenue*		Forfeited Discounts		Projected Revenues
January	9,144	$	1,430,853	$	2,917	$	1,433,770
February	8,076	$	1,263,732	$	2,917	$	1,266,649
March	8,281	$	1,295,811	$	2,917	$	1,298,728
April	7,127	$	1,115,233	$	2,917	$	1,118,150
May	7,652	$	1,197,385	$	2,917	$	1,200,302
June	7,841	$	1,226,960	$	2,917	$	1,229,877
July	9,222	$	1,443,059	$	2,917	$	1,445,976
August	8,965	$	1,402,843	$	2,917	$	1,405,760
September	8,020	$	1,254,970	$	2,917	$	1,257,887
October	8,018	$	1,254,657	$	2,917	$	1,257,574
November	8,369	$	1,309,581	$	2,917	$	1,312,498
December	8,988	$	1,406,442	$	2,913	$	1,409,355
Totals	99,703	$	15,601,525	$	35,000	$	15,636,525

*Revenue does not include unbilled revenue.

ATTACHMENT F

WELLSBORO ELECTRIC COMPANY

Pursuant to the Pennsylvania Utility Commission's State Tax Adjustment Surcharge (STAS) Procedures.

			Distribution Only
1	Net Operating Income Excluding Income Taxes		$1,493,687
2			
3	Synchronized interest expense:		
4	Rate base		14,653,172
5	Less: CWIP		0
6	Rate base for interest compuation		14,653,172
7	Weighted Cost of debt		2.457%
8	Synchronized interest expense		359,975
9	Taxable income before depreciation tax adjustments		1,133,712
10			
11	Pennsylvania depreciation adjustment:		
12	Tax depreciation (using DDB method)		(1,045,406)
13	Book depreciation		1,331,977
14	Pennsylvania depreciation adjustment		286,571
15	Pennsylvania taxable income		1,420,283
16	Regulatory Pennsylvania income tax expense	9.99%	141,886
		7.99%	113,481
17	Regulatory Pennsylvania Income Tax Expense Credit		(28,406)
	Monthly CNIT Credit		(2,367)

Operating Expenses

	2019	2020	2021	2022	2023	2024	1st Qtr 2025 Balance
Distribution Operating Expenses							
Operation, Supervision & Engineering	81,013.05	1,208.84	18.15	-	-	8,120.83	-
Station Expense	-	-	243.90	74.37	-	-	-
Overhead Line Expense	33,789.87	19,061.94	15,614.21	6,665.79	685.67	769.70	673.78
Street Lighting Expense	4,669.97	2,228.80	493.48	-	674.98	146.00	-
Meter Expense	58,554.29	31,807.23	36,301.23	41,054.59	33,643.75	36,983.28	5,632.10
Customer Installation Expense	12,746.46	5,307.03	99.60	-	-	206.47	-
Miscellaneous Distribution Expense	232,673.62	233,359.23	151,049.73	201,682.52	170,671.11	173,944.04	38,903.17
Rents	21,000.65	20,502.17	44,911.99	32,396.64	30,716.78	32,950.44	7,799.04
Distribution Operating Expenses Total	**444,447.91**	**313,475.24**	**248,732.29**	**281,873.91**	**236,392.29**	**253,120.76**	**53,008.09**
Distribution Maintenance Expenses							
Maintenance, Supervision & Engineering	55,622.24	43,849.90	61,058.93	68,775.19	85,710.48	97,875.02	31,373.64
Maintenance of Structures	296.14	1,175.48	464.05	687.46	1,847.71	-	178.26
Maintenance of Station Equipment	13,792.21	23,464.62	9,092.50	9,391.98	5,697.14	3,210.20	1,253.23
Maintenance of Overhead Lines	584,648.20	742,414.32	712,829.82	762,068.47	836,768.64	869,787.87	197,158.78
Maintenance of Underground Lines	21,498.29	28,923.85	52,754.63	48,059.59	28,435.79	30,206.08	6,056.81
Maintenance of Line Transformers	15,712.70	9,148.66	2,547.33	8,897.72	5,677.47	14,532.38	530.29
Maintenance of Street Lighting and signal system	145.22	742.50	747.11	4,239.41	2,990.96	1,611.76	619.21
Maintenance of Meters	60,174.72	73,141.44	70,080.28	79,972.92	75,467.27	64,505.30	19,855.61
Distribution Maintenance Expenses Total	**751,889.72**	**922,860.77**	**909,574.65**	**982,092.74**	**1,042,595.46**	**1,081,728.61**	**257,025.83**
Customer Accounting & Collection Expense							
Supervision	-	-	-	-	-	3,654.38	-
Meter Reading Expense	8,108.82	20,411.33	17,017.04	18,616.38	19,808.19	21,775.28	3,498.48
Customer Records & Collection Expense	603,022.90	588,982.48	637,325.48	727,808.73	872,948.87	903,979.98	237,254.73
Uncollectible Accounts	75,617.80	20,000.00	28,000.00	19,666.72	-	-	-
Customer Records & Collection Expense Total	**686,749.52**	**629,393.81**	**682,342.52**	**766,091.83**	**892,757.06**	**929,409.64**	**240,753.21**
Sales Promotion Expense							
Customer Assistance Expense	1,214.22	1,122.34	2,014.41	1,504.32	2,029.53	180.39	447.21
Customer Service - Public Relations - Commercial	1,233.22	-	-	816.40	314.00	800.00	941.00
Supervision	-	-	-	-	-	-	-
Advertising Expense	1,544.00	1,825.13	2,508.62	2,933.96	1,738.00	2,191.00	294.00
Sales Promotion Expense Total	**3,991.44**	**2,947.47**	**4,523.03**	**5,254.68**	**4,081.53**	**3,171.39**	**1,682.21**
Administrative & General Expenses							
Administrative & General Salaries	424,872.28	678,593.43	580,954.85	628,734.61	652,638.72	757,901.37	185,471.76
Office Supplies & Expense	75,462.64	83,978.10	79,035.69	65,096.77	61,925.37	112,900.44	22,435.49
Working Capital Claim	111,723.79	213,661.93	72,969.10	74,357.05	87,889.08	137,115.05	45,106.85
Outside Services Employed	59,914.46	56,403.29	54,104.22	48,306.33	51,268.11	53,098.02	13,433.62
Property Insurance	-	-	-	-	-	-	-
Employee Pensions & Benefits	-	-	-	1,083.78	-	-	-
Regulatory Commission Expense	100,546.84	124,452.44	146,367.72	144,821.72	68,366.08	42,985.00	10,746.24
Directors Expense	85,754.86	82,505.98	81,027.38	85,988.28	101,167.34	83,256.69	18,266.94
Misc. General Expense - GPS Mapping	2,915.00	78,102.88	31,527.59	8,369.07	3,074.00	-	662.49
Misc. General Expense - Industry Assn. Dues	1,113.00	897.00	898.75	1,117.00	1,113.40	1,147.00	1,080.00
Rents	2,373.06	2,436.66	2,419.92	2,436.66	2,442.24	3,610.62	1,000.02
Maintenance of General Property	62,960.15	74,602.72	79,585.28	58,348.24	112,579.95	72,185.85	18,916.91
Administrative & General Expense Total	**927,636.08**	**1,395,634.43**	**1,128,890.50**	**1,118,659.51**	**1,142,464.29**	**1,264,200.04**	**317,120.32**
Total Operating Expenses	**2,814,714.67**	**3,264,311.72**	**2,974,062.99**	**3,153,972.67**	**3,318,290.63**	**3,531,630.44**	**869,589.66**

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Statement of Utility Plant

	2019	2020	2021	2022	2023	2024	1st QTR 2025
Distribution Plant							
Land & Land Rights	178,334.71	178,334.71	178,334.71	178,334.71	178,334.71	178,334.71	178,334.71
Structures & Improvements	109,167.57	109,167.57	109,167.57	109,167.57	-	-	-
Station Equipment	3,736,009.92	4,304,358.66	3,956,590.88	3,956,684.10	3,979,530.10	3,992,794.61	3,992,794.61
Poles, Towers, & Fixtures	9,844,164.62	10,227,483.18	10,811,919.27	11,469,263.89	12,455,793.24	13,456,216.24	13,605,442.64
Overhead Conductors & Devices	3,618,731.34	3,710,672.35	4,061,769.56	4,860,901.19	5,529,145.46	6,083,842.68	6,069,822.61
Underground Conduit	26,899.09	26,899.09	26,899.09	26,899.09	26,899.09	26,899.09	26,899.09
Underground Conductors & Devices	915,739.84	939,952.25	957,984.65	960,369.32	1,008,035.17	1,011,553.48	1,014,226.42
Transformers	2,495,180.75	2,545,689.36	2,651,336.72	2,705,949.80	2,923,909.87	3,198,831.56	3,249,159.52
Services	835,994.56	848,292.98	852,260.78	849,189.67	849,839.34	855,310.76	856,947.06
Underground Services	1,160,936.69	1,185,041.72	1,237,418.34	1,266,452.78	1,300,814.95	1,344,546.64	1,344,809.00
Meters	930,018.62	944,633.35	965,512.96	973,115.09	986,942.48	1,011,480.19	1,028,258.30
Installation on Customer Premises' - Customer Lights	274,050.64	292,325.63	299,481.84	330,227.32	373,326.87	369,616.20	329,942.38
Installation on Customer Premises' - Street Lights	82,833.78	98,817.13	123,217.01	120,366.12	118,916.23	119,273.41	109,406.70
Total Distribution Plant	**24,208,062.13**	**25,411,667.98**	**26,231,893.38**	**27,806,920.65**	**29,731,487.51**	**31,648,699.57**	**31,806,043.04**
General Plant							
Structures & Improvements - Office	583,657.35	583,657.35	614,690.10	692,958.84	2,486,359.91	5,663,858.30	5,663,858.30
Structures & Improvements - Other	341,105.21	341,105.21	343,555.21	343,555.21	879,044.58	879,044.58	879,044.58
Office Furniture & Equipment	678,913.22	583,047.81	585,211.39	595,561.03	606,627.93	779,493.16	786,792.94
Transportation Equipment	1,018,962.79	1,317,232.57	1,304,855.85	1,436,783.95	1,646,620.27	1,532,012.07	1,532,012.07
Tools, Shop, & Garage Equipment	76,772.99	76,772.99	89,071.68	87,904.08	90,045.43	90,045.43	90,045.43
Laboratory Equipment	96,080.92	96,080.92	96,080.92	96,080.92	96,080.92	15,431.27	15,431.27
Power Operated Equipment	80,519.24	80,519.24	80,519.24	80,519.24	98,149.49	89,814.74	89,814.74
Communications Equipment	248,922.90	248,922.90	248,922.90	260,402.26	110,327.23	117,902.01	117,902.01
Miscellaneous Equipment	288.72	288.72	288.72	288.72	-	-	-
Organization	1,046.20	1,046.20	1,046.20	1,046.20	1,046.20	1,046.20	1,046.20
Miscellaneous Intangible Plant	284,587.90	284,587.90	284,587.90	284,587.90	284,587.90	284,587.90	284,587.90
Total General Plant	**3,410,857.44**	**3,613,261.81**	**3,648,830.11**	**3,879,688.35**	**6,298,889.86**	**9,453,235.66**	**9,460,535.44**
Total Plant in Service	**27,618,919.57**	**29,024,929.79**	**29,880,723.49**	**31,686,609.00**	**36,030,377.37**	**41,101,935.23**	**41,266,578.48**
Net Additions to Plant		**1,406,010.22**	**855,793.70**	**1,805,885.51**	**4,343,768.37**	**5,071,557.86**	**164,643.25**
Non-Utility Plant							
Non-Utility Plant - No Depreciation	51,908.61	51,908.61	51,908.61	51,908.61	51,908.61	51,908.61	51,908.61
Non-Utility Plant - Apartment House	154,174.48	154,174.48	154,174.48	154,174.48	154,174.48	154,174.48	154,174.48
Non-Utility Plant - Call Center	227,695.04	227,695.04	227,695.04	227,695.04	-	-	-
Non-Utility Plant - Propane Businese	-	-	-	-	-	-	-
Total Non-Utility Plant	**433,778.13**	**433,778.13**	**433,778.13**	**433,778.13**	**206,083.09**	**206,083.09**	**206,083.09**

FTY & FPFTY Wage & Salary Increase Detail

Wellsboro Electric Company

Exhibit JC-5

	Non-Union Wages					
	2024	2025		2026		
	$$$	$$$	% of Total Increase	$$$	% of Total Increase	
Total Budgeted Wages	$ 945,592	$ 985,502		$ 1,054,120		
Total Wage Increase		$ 118,684		$ 124,569		
COLA		$ 67,319	56.7%	$ 72,467	58.2%	
Market		$ 41,000	34.5%	$ 41,000	32.9%	
Merit		$ 10,365	8.7%	$ 11,103	8.9%	
	WECo Union Wages					
	2024	2025		2026		
	$$$	$$$	% of Total Increase	$$$	% of Total Increase	
Total Budgeted Wages	$ 914,658	$ 919,329		$ 955,649		
CBA Increase		$ 31,387	100.0%	$ 32,677	100.0%	
Combined Total Budgeted Wages	**$ 1,860,250**	**$ 1,904,830**		**$ 2,009,769**		

BEFORE
THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	**:**	
	:	
v.	**:**	**Docket No. R-2025-3054392**
	:	
Wellsboro Electric Company	**:**	

REBUTTAL TESTIMONY

AND EXHIBIT

OF

JILL CAMPBELL

ON BEHALF OF

WELLSBORO ELECTRIC COMPANY

AUGUST 13, 2025

BEFORE
THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	**Docket No. R-2025-3054392**
`	:	
Wellsboro Electric Company	:	

REBUTTAL TESTIMONY OF JILL CAMPBELL
ON BEHALF OF WELLSBORO ELECTRIC COMPANY

Q. Please state your name and business address.

A. My name is Jill Campbell, and my business address is 33 Austin Street, Wellsboro, Pennsylvania.

Q. Are you the same Jill Campbell who previously submitted Direct Testimony in this proceeding on behalf of Wellsboro Electric Company ("Wellsboro" or "Company")?

A. Yes. Terms defined in my direct testimony have the same meaning in this rebuttal testimony.

Q. What is the purpose of your testimony today?

A. The purpose of my testimony is to rebut the testimony of the Bureau of Investigation and Enforcement's ("I&E") Zachari Walker regarding the proposed disallowance of $12,804 in membership dues and subscriptions for ratemaking purposes, the $258,688 disallowance related to GL 588 miscellaneous distribution expenses, the request for additional detail regarding the $81,880 in administrative and general expenses, and the need for clarification on GL 932 maintenance of general property. My testimony also addresses the statement made by the Office of Consumer Advocate ("OCA") witness Greg Walker regarding

purchased power costs. I also will provide updated actual expenses and plant additions/retirements through the 2nd Quarter 2025.

Q. Do you agree with Mr. Walker's basis for disallowing $12,804 in membership dues and subscriptions claims for ratemaking purposes?

A. No, I do not agree. Mr. Walker asserts that sufficient detail was not provided in response to I&E-RE-10-D because the payee and account number were not included. The table below provides the requested information, including the payee and account details, to fully support the Company's claim for membership dues and subscriptions.

Account Number	Bank Charges	2024	2025	2026
921.00	C&N Bank	5,134	6,000	6,000
	Subscriptions	**2024**	**2025**	**2026**
921.40	Handy Whitman Index	175	175	175
921.40	Wellsboro Gazette	93	100	100
921.40	Adobe Pro for Teams Subscription	1,831	1,900	1,900
921.40	Notary Fees	693	1,050	1,050
921.40	Zoom Subscription	169	175	175
		2,961	3,400	3,400
	Membership Dues & Subscriptions	**2024**	**2025**	**2026**
930.30	Energy Association	957	957	957
921.40	PA Chamber of Business & Industry	1450	1450	1450
930.30	Voam	190	190	190
921.40	Wellsboro Chamber of Commerce	775	775	775
		3372	3372	3372
	Lobbying Expenses	**2024**	**2025**	**2026**
930.30	Energy Association	29	32	32

Q. Do you agree with Mr. Walker's rationale for disallowing the full $285,688 FPFTY for GL 588 miscellaneous distribution expense claimed for ratemaking purposes?

A. No, I do not agree. Mr. Walker denied Wellsboro's recovery for all expenses in this Account based on our purported failure to provide sufficient detail to assess whether the

Company's miscellaneous distribution expense claim is appropriate for ratemaking purposes. In response, we are providing a detailed breakdown of General Ledger Account 588 subaccounts.

		2023	2024	2025	2026
588.00	Repair of Customer Property	1,084.29	-	5,000.00	5,000.00
588.00	Misc. Expense	0.09	(1,388.81)	500.00	500.00
588.00	Right of Way Filing Fee's	-	-	500.00	500.00
588.00	Tree Replacement Program	-	-	800.00	800.00
		1,084.38	(1,388.81)	6,800.00	6,800.00
588.20	Schools and Trainings	9,205.11	11,770.29	15,000.00	15,000.00
		9,205.11	11,770.29	15,000.00	15,000.00
588.40	CDL Medical Cards	260.00	390.00	650.00	650.00
588.40	Safety Meetings/Safety Equipment	2,105.18	3,917.45	7,500.00	7,500.00
588.40	Random Drug and Alcohol Testing	765.00	693.00	1,500.00	1,500.00
		3,130.18	5,000.45	9,650.00	9,650.00
588.01	Misc Distribution Expense-Labor	37,840.12	29,488.68	61,874.63	64,014.38
588.02	Misc Distribution Expense-Overhead	48,792.87	40,264.33	62,211.00	62,486.00
588.11	Misc Dist Exp-General Meeting-Labor	7,872.03	11,083.74	8,466.55	8,766.41
588.12	Misc Dist Exp-General Meeting-Overhead	5,224.99	8,630.60	9,349.00	9,351.00
588.21	Misc Dist Exp-Outside Training-Labor	5,186.04	10,140.62	11,505.56	11,845.96
588.22	Misc Dist Exp-Outside Training-Overhead	1,559.48	2,481.95	5,245.00	5,556.00
588.31	Misc Dist Exp-On Call Stand-By-Labor	12,639.15	12,129.17	14,798.67	14,651.47
588.32	Misc Dist Exp-On Call Stand-By-Overhead	3,574.82	3,096.93	6,746.00	6,873.00
588.41	Misc Dist Exp-Safety Meeting Training-Labor	22,120.31	28,264.96	39,910.15	41,188.13
588.42	Misc Dist Exp-Safety Meeting Training-Overhead	12,441.63	12,981.13	28,865.00	29,506.00
		157,251.44	158,562.11	248,971.56	254,238.35
		170,671.11	173,944.04	280,421.56	285,688.35

These include costs related to employee training, which is critical for apprentice development, journeyman education, and the meter department's ability to stay current with evolving AMI technology. The account also includes mandatory CDL medical card expenses for commercial drivers, which are conditions of employment.

Other items include safety meetings, safety equipment, and random drug and alcohol testing, which is mandatory for employment, and it supports our safety culture and safe work practices.

Labor projections for this account reflect annual wage increases, as well as adjustments due to staffing changes and workload distribution. In 2024, a temporary vacancy in the

General Utility position contributed to lower labor costs. Additionally, a higher proportion of labor was charged to capital projects that year, further reducing expense allocations to this GL. Since then, responsibilities have been realigned among existing staff, and the Company is now budgeting for the workforce to have a normalized balance between capital and expense labor. This results in an appropriate reallocation of labor costs to this account for the test year.

Labor activities captured within this GL include PA One Call notifications, substation and regulator inspections, safety meetings and training, and on-call coverage to ensure prompt response to system outages. The budgeted labor levels reflect the resources needed to maintain safe, reliable operations across our service territory under typical conditions.

Other general miscellaneous distribution expenses include the repair of customer property. While the Company has not incurred a lot of expense under the repair of customer property, miscellaneous expenses, right of way filing fees, and the tree replacement program budget line items in recent years, it remains a reasonable and prudent expense to include in the budget. These categories represent a contingency for events that are unpredictable but plausible—such as accidental damage to customer property caused by utility operations (e.g., during service restoration, equipment failure, or construction work), filing fees for new projects, or the need for tree replacements on customer property.

Omitting these line items entirely would leave no allocated funds for addressing such occurrences should they arise, potentially requiring the reallocation of resources from other operational areas or delaying response and repair efforts. Including a modest, consistent amount in the budget ensures readiness, supports responsible financial planning, and

demonstrates the Company's commitment to maintaining positive customer relationships by addressing unforeseen issues promptly.

All costs in this category are reasonable, directly related to the safe and reliable operation of the distribution system and therefore appropriate for recovery through rates.

Q. How do you respond to Mr. Walker's concern that the Company has not provided sufficient justification for the $81,880 increase in forecast Administrative and General (A&G) overhead expense?

A. Further detailed breakdown of A&G expenses are provided below:

Description	2023	2024	2025	2026
Admin Salaries	281,014.75	304,110.07	334,261.75	361,797.26
Admin Salaries OH	351,030.64	402,852.45	468,335.00	484,732.00
Continuing Education Management & Staff	20,593.33	50,938.85	67,300.00	64,700.00
	652,638.72	757,901.37	869,896.75	911,229.26

The percentage of overheads allocated to administrative salaries increased from 125% in 2023 actuals to 132% in 2024 actuals and is projected at 140% and 134% for 2025 and 2026, respectively. This represents a 7.2% increase in overheads as a percentage of salaries from 2023 to the 2026 budget, with a percentage difference over that period of 29% in labor and 38% in overheads.

A portion of the A&G expenses includes continued investment in education and professional development of staff and management. The Company has prioritized educational opportunities to strengthen cross-training and operational resilience by ensuring multiple employees are proficient in key systems, which helps maintain continuity during absences and turnover. These investments also drive efficiency improvements and cost savings, as well-trained employees use systems more effectively, reducing manual processes, data entry errors, and customer service issues. Additionally, providing

professional development opportunities supports employee retention by increasing engagement and job satisfaction, which is more cost-effective than external hiring. Finally, these initiatives support succession planning which is driven by our president/CEO and Board of Directors to prepare the next generation of manager, supervisors, and employees to assume leadership roles as retirements or vacancies occur.

Q. How do you respond to the claim that the Company did not provide a detailed breakdown of the cost drivers contributing to the increase in Account 932, as referenced in response to I&E-RE-20-D?

A. In response to I&E-RE-20-D, I provided key components of Account 932 to support the budgeted costs. The Company experienced irregular expenses during the construction of its new building, with some items temporarily elevated and others reduced. Now that the building project is complete, we expect maintenance-related expenses in this account to return to more normalized and levelized levels. However, it is prudent to budget for a typical winter season, including snow removal services, especially given the recent trend of milder winters that may not reflect a typical year. Additionally, with construction concluded, the Company has resumed routine outdoor maintenance activities, such as lawn care, blacktop coating, HVAC checks, and other various maintenance to catch issues before they become major expenses, which were minimized or temporarily suspended during the building period.

The Company acknowledges that, as part of the transition to a revised budgeting process, certain IT-related expenses were inadvertently allocated twice, once within departmental budgets and again within the centralized IT budget. Upon review, we identified approximately $34,816 in duplicated IT-related costs for FTY 2025 and $40,240 in

duplicated IT-related costs for FPFTY 2026. To avoid any potential overstatement, the Company is voluntarily removing $40,240 from its FPFTY 2026 claim. A revised, more detailed breakdown is shown below.

		2023	2024	2025	2026
932.00	Dumpster, Pole Yard	$ 8,456.95	$ 7,153.50	$ 8,500.00	$ 8,500.00
932.00	Emergency Generator Maintenance	$ -	$ -	$ 3,000.00	$ 3,000.00
932.10	Alarm System Maintenance	$ 5,845.58	$ 5,714.50	$ 1,500.00	$ 1,500.00
932.10	Maintenance, Office Building	$ 3,824.46	$ 2,785.33	$ 2,500.00	$ 2,500.00
932.20	Maintenance, SCADA,AMI,ETC.	$ -	$ -	$ 500.00	$ 500.00
932.30	Maintenance, Operations Building	$ 1,682.63	$ 8,619.06	$ 3,000.00	$ 3,000.00
932.30	Maintenance, Blacktop Coating	$ -	$ -	$ 9,550.00	$ 9,550.00
932.10	Snow Removal, Salting of Parking Areas	$ 2,724.48	$ 2,445.00	$ 7,000.00	$ 7,000.00
		$ 22,534.10	$ 26,717.39	$ 35,550.00	$ 35,550.00
932.70	Mailing Machine Maintenance	$ 702.02	$ 546.96	$ 1,800.00	$ 1,800.00
932.70	Office Equipment Maintenance	$ 114.48	$ 114.48	$ 1,000.00	$ 1,000.00
932.70	Computers/Repairs/Service	$ 431.12	$ 1,246.63	$ 1,000.00	$ 1,000.00
		$ 1,247.62	$ 1,908.07	$ 3,800.00	$ 3,800.00
932.00	Natural Gas	$ 9,863.23	$ 3,880.46	$ 4,500.00	$ 4,500.00
932.00	Cylinder Rental	$ 2,077.29	$ 2,568.75	$ 1,320.00	$ 1,320.00
932.00	Generator Repairs & Maintenance	$ 3,618.92	$ 1,557.14	$ 3,500.00	$ 3,500.00
932.00	Crew Building Water (Boro)	$ 717.64	$ 581.38	$ 780.00	$ 780.00
932.00	Crew Culligan	$ 1,026.42	$ 1,523.20	$ 1,500.00	$ 1,500.00
932.00	IT Budget	$ 20,929.24	$ 22,085.84	$ 29,059.59	$ 23,635.59
		$ 38,232.74	$ 32,196.77	$ 40,659.59	$ 35,235.59
932.01	Maintenance of General Property-Labor	$ 49,935.71	$ 10,176.44	$ 10,814.41	$ 11,134.85
932.02	Maintenance of General Property-Overhead	$ -	$ -	$ 4,930.00	$ 5,223.00
932.31	Maint Gen Property-Plant Building-Labor	$ 629.78	$ 1,504.94	$ 1,563.89	$ 1,611.39
932.32	Maint Gen Property-Plant Building-Overhead	$ -	$ -	$ 713.00	$ 756.00
		$ 50,565.49	$ 11,681.38	$ 18,021.30	$ 18,725.24
		$ 112,579.95	**$ 72,503.61**	**$ 98,030.89**	**$ 93,310.83**

Q. Has the Company identified any corrections or clarifications to the actual purchased power cost for the Historic Test Year ("HTY") 2024 in response to Mr. Meyer's concern regarding the revenue requirement adjustment proposed to remove purchased power expenses from the Company's revenues and expenses?

A. Yes; however, it does not impact the Company's revenue requirement for distribution service. Upon review, I identified that the actual purchased power cost for the HTY 2024, as shown in Cell C22 (Line 13), should be $6,429,293. This corrects an error in the original filing, which inaccurately reported the actual purchased power cost. As a result, the true difference between the actual and projected purchased power costs is approximately

$474,034. This variance is largely attributable to normal fluctuations in over- and under-collections related to the E-Factor mechanism, as well as the inherent uncertainty involved in forecasting purchased power costs during the budgeting process.

Q. Please explain how the Company's generation costs are recovered.

A. Our generation costs are recovered through automatic adjustment mechanisms that were approved in our default service proceedings. The GSSR-1 is a fixed rate with just a kWh component for customers with a Billing Demand under 400 kW. The GSSR-2 is a variable rate for customers with a Billing Demand Over 400 kW, which includes kWh and demand-based components. We change the GSSR-1 rate twice per year based on our forward projections of the purchased power costs and our projections of sales to that group of customers. We also calculate an e-factor to address any overcollection or undercollection of the prior period costs and revenues (in comparison to the projections used to establish the prior period GSSR-1 rate). The GSSR-2 includes a real time hourly price (kWh), the supplier adder (kWh), a Company administrative charge (kWh), a capacity charge (kW) and a transmission charge (kW). All elements of the GSSR-2 retail rate are customer-specific, except the supplier adder and Company administrative charge, which are uniform for all GSSR-2 customers. Starting with the period that began on June 1, 2025, we also will be calculating an E-Factor for the GSSR-2 rate.

Q. Does the Commission separately audit the GSSR mechanisms?

A. Yes. Our GSSR mechanisms are periodically audited by the Commission.

Q. Does the unbundling of the generation costs streamline the process for removing generation costs and revenues for the rate case?

A. Yes. Unbundling enables us to account for the generation costs and revenues separately from distribution.

Q. Finally, can you provide actual expenses and plant additions/retirements for the FTY?

A. Yes. Attached as Exhibit__(JC-1R) are the updated expenses and plant, by account, through the 2nd Quarter 2025.

Q. Does this complete your Rebuttal Testimony?

A. Yes.

Wellsboro Statement No. 5R

BEFORE
THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	**Docket No. R-2025-3054392**
	:	
Wellsboro Electric Company	:	

EXHIBIT

OF

JILL CAMPBELL

ON BEHALF OF

WELLSBORO ELECTRIC COMPANY

AUGUST 13, 2025

EXHIBIT__(JC-1R)

Operating Expenses

	1st QTR 2025 Balance	2nd QTR 2025 Balance	3rd QTR 2025 Balance	4th QTR 2025 Balance
Distribution Operating Expenses				
Operation, Supervision & Engineering	-	-	-	-
Station Expense	-	-	-	-
Overhead Line Expense	673.78	(1,236.46)	-	-
Street Lighting Expense	-	-	-	-
Meter Expense	5,632.10	14,604.56	-	-
Customer Installation Expense	-	-	-	-
Miscellaneous Distribution Expense	38,903.17	89,413.81	-	-
Rents	7,799.04	15,598.08	-	-
Distribution Operating Expenses Total	53,008.09	118,379.99	-	-
Distribution Maintenance Expenses				
Maintenance, Supervision & Engineering	31,373.64	60,016.04	-	-
Maintenance of Structures	178.26	178.26	-	-
Maintenance of Station Equipment	1,253.23	1,757.58	-	-
Maintenance of Overhead Lines	197,158.78	481,667.03	-	-
Maintenance of Underground Lines	6,056.81	17,057.44	-	-
Maintenance of Line Transformers	530.29	928.77	-	-
Maintenance of Street Lighting and signal system	619.21	740.30	-	-
Maintenance of Meters	19,855.61	39,076.07	-	-
Distribution Maintenance Expenses Total	257,025.83	601,421.49	-	-
Customer Accounting & Collection Expense				
Supervision	-	-	-	-
Meter Reading Expense	3,498.48	6,997.72	-	-
Customer Records & Collection Expense	237,254.73	473,093.58	-	-
Uncollectible Accounts	-	1,281.00	-	-
Customer Records & Collection Expense Total	240,753.21	481,372.30	-	-
Sales Promotion Expense				
Customer Assistance Expense	447.21	616.25	-	-
Customer Service - Public Relations - Commercial	941.00	941.00	-	-
Supervision	-	-	-	-
Advertising Expense	294.00	1,355.76	-	-
Sales Promotion Expense Total	1,682.21	2,913.01	-	-
Administrative & General Expenses				
Administrative & General Salaries	185,471.76	383,066.02	-	-
Office Supplies & Expense	22,435.49	47,048.89	-	-
Working Capital Claim	45,106.85	68,695.09	-	-
Outside Services Employed	13,433.62	27,928.88	-	-
Property Insurance	-	-	-	-
Employee Pensions & Benefits	-	-	-	-
Regulatory Commission Expense	10,746.24	21,492.48	-	-
Directors Expense	18,266.94	38,479.00	-	-
Misc. General Expense - GPS Mapping	662.49	1,324.98	-	-
Misc. General Expense - Industry Assn. Dues	1,080.00	1,080.00	-	-
Rents	1,000.02	2,000.04	-	-
Maintenance of General Property	18,916.91	26,509.80	-	-
Administrative & General Expense Total	317,120.32	617,625.18	-	-
Total Operating Expenses	**869,589.66**	**1,821,711.97**	**-**	**-**

Utility Plant

Distribution Plant				
Land & Land Rights	178,334.71	178,334.71	-	-
Structures & Improvements	-	-	-	-
Station Equipment	3,992,794.61	3,995,974.61	-	-
Poles, Towers, & Fixtures	13,605,442.64	13,824,836.50	-	-
Overhead Conductors & Devices	6,069,822.61	6,210,631.66	-	-
Underground Conduit	26,899.09	26,899.09	-	-
Underground Conductors & Devices	1,014,226.42	1,015,303.73	-	-
Transformers	3,249,159.52	3,357,234.39	-	-
Services	856,947.06	858,614.95	-	-
Underground Services	1,344,809.00	1,351,957.84	-	-
Meters	1,028,258.30	1,029,157.42	-	-
Installation on Customer Premises' - Customer Lights	329,942.38	331,095.37	-	-
Installation on Customer Premises' - Street Lights	109,406.70	109,027.21	-	-
Total Distribution Plant	**31,806,043.04**	**32,289,067.48**	**-**	**-**
General Plant				
Structures & Improvements - Office	5,663,858.30	5,663,858.30	-	-
Structures & Improvements - Other	879,044.58	879,044.58	-	-
Office Furniture & Equipment	786,792.94	812,985.56	-	-
Transportation Equipment	1,532,012.07	1,755,555.07	-	-
Tools, Shop, & Garage Equipment	90,045.43	90,045.43	-	-
Laboratory Equipment	15,431.27	15,431.27	-	-
Power Operated Equipment	89,814.74	89,814.74	-	-
Communications Equipment	117,902.01	117,902.01	-	-
Miscellaneous Equipment	-	-	-	-
Organization	1,046.20	1,046.20	-	-
Miscellaneous Intangible Plant	284,587.90	284,587.90	-	-
Total General Plant	**9,460,535.44**	**9,710,271.06**	**-**	**-**
Total Plant in Service	41,266,578.48	41,999,338.54	-	-
Net Additions to Plant YTD				897,403.31
Non-Utility Plant				
Non-Utility Plant - No Depreciation	51,908.61	51,908.61	-	-
Non-Utility Plant - Apartment House	154,174.48	154,174.48	-	-
Non-Utility Plant - Call Center	-	-	-	-
Non-Utility Plant - Propane Businese	-	-	-	-
Total Non-Utility Plant	**206,083.09**	**206,083.09**	**-**	**-**

BEFORE

THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	**:**	
	:	
v.	**:**	**Docket No. R-2025-_____**
	:	
Valley Energy, Inc.:		

DIRECT TESTIMONY

AND EXHIBITS

OF

HOWARD S. GORMAN

ON BEHALF OF

VALLEY ENERGY, INC.

APRIL 30, 2025

BEFORE

THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	**:**	
	:	
v.	**:**	**Docket No. R-2025-_____**
	:	
Valley Energy, Inc.	**:**	

DIRECT TESTIMONY OF HOWARD S. GORMAN
ON BEHALF OF VALLEY ENERGY, INC.

Q. Please state your name, occupation and business address.

A. My name is Howard Gorman. I am the President of HSG Group, Inc., a consulting firm specializing in utility rate and regulatory matters, located in Great Neck, NY.

Q. Please summarize your educational background and professional experience.

A. My educational background, professional experience and summary of testimony are outlined in Attachment A.

Q. Please state on whose behalf you are testifying and describe the purposes of your testimony.

A. I am testifying on behalf of the petitioner, Valley Energy, Inc. ("Valley" or "Company"). The purposes of my testimony are:

- To develop the Fully Projected Future Test Year ("FPFTY") Revenue Requirement and Rate Base, and Future Test Year ("FTY") net income, based on Historic Test Year ("HTY") data and appropriate adjustments; and

- To present the Company's proposed Rates and Charges that produce the overall revenue requirement, as well as the proof of revenue and bill comparisons at the proposed rates.

The rates proposed in this filing are for the FPFTY; the FPFTY Revenue Requirement and Rate Base were determined for Distribution only. Revenue and costs related to Valley's obligation as a Supplier of Last Resort have been excluded from the analysis.

In my testimony, dollar amounts (excluding rates and charges) are rounded to the nearest thousand dollars; in computing revenue requirements and rates, whole dollars are used.

Q. What FPFTY, FTY and HTY were used?

A. The HTY is Valley's actual results for calendar year 2024. The FTY is Valley's forecast for 2025 and the FPFTY is Valley forecast for 2026. Valley uses a calendar year for financial reporting. The supporting calculations and data for the filing are in Exhibit__(HSG-1). Throughout my testimony, I will reference the various schedules within Exhibit__(HSG-1) that explain the calculations and results. References in my testimony are to *Exhibit __ (HSG-1)*; for example, *Schedule C1* refers to *Exhibit __ (HSG-1), Schedule C1*.

Q. When will the new rates take effect?

A. If the Commission suspends the filing for the statutory period, then the rates will take effect on January 30, 2026; however, the rate changes could be effective sooner if the Commission doesn't suspend the filing or if the parties reach a settlement that includes an accelerated effective date and that settlement is approved by the Commission.

Q. Is the presented FPFTY consistent with the Commission's revised regulations for rate cases using a FPFTY?

A. Yes. Earlier this year, the Commission adopted revised regulations for Sections 53.51-53.56 that are pending before the Independent Regulatory Review Commission, with final action expected soon after the Company submits this filing. The revised regulations contain the following definition of FPFTY:

> A 12-consecutive-month period beginning with the first month that the new rates will be in effect after application of the full suspension period permitted under section 1308(d) of the Public Utility Code, 66 Pa.C.S. § 1308 (relating to voluntary changes in rates) and reflecting estimated results of operations of the public utility.

Q. Please summarize the results of your testimony regarding Valley's revenue requirement.

A. Under its present rates, Valley is forecast to have net operating income of approximately $937,000 in FPFTY 2026, representing a return on rate base of 3.72%. To produce the return of 8.27% that Company witnesses Mr. D'Ascendis and Mr. Kucan recommend would require an increase in revenue of $1,626,000, an increase of 25.1% over Distribution revenue at present rates. This equals an increase in total revenue (distribution and supply) of 19% of Valley's 2024 total revenue.

The revenue produced by the proposed rates, $8,109,000 (plus $24,000 Other revenue, for total revenue of $8,133,000) would recover the costs forecast to be incurred by Valley in the FPFTY, including a return on rate base of 8.27%. To produce the total revenue requirement, the Company proposes to increase the revenue from each class, excluding customers taking service under negotiated contracts, by 29.6%. (Schedule C1).

Valley is proposing that the rates and charges subject to the Tariff be increased as shown on Schedule B5.

Q. Please describe the approach used to develop the revenue requirement and the proposed rates.

A. *First*, a forecast of Valley's sales and distribution revenue for the FTY and FPFTY was developed. A summary of Valley's sales and revenues for the HTY, FTY and FPFTY is presented in Schedule B.

For HTY 2024, sales and revenue information was obtained from Valley's accounting and financial records. This information is presented on Schedule B1, with computations on Schedule B1-1. Schedule B1-2 reconciles the revenue computed using HTY 2024 billing units and current rates, to revenue to Valley 2024 financial statements.

For FTY 2025, sales and revenue information is presented on Schedule B2, with supporting computations on Schedule B2-1. For FPFTY 2026, sales and revenue information is presented on Schedule B4. FPFTY revenue at present rates is computed on Schedule B4-1, and FPFTY revenue at proposed rates is computed on Schedule B4-2. The development of the forecasts for the number of customers and the sales volumes for the FTY and FPFTY is based on regression analyses, which are discussed below.

Second, costs were obtained for the HTY, and forecasted costs were obtained for the FTY and FPFTY. These costs, detailed by account, are presented on Schedule C1-1.

Third, the Rate Base for the HTY, FTY and FPFTY was developed, using information from Valley's HTY financial statements and projected capital expenditures for the FTY and FPFTY. The rate base adjusts the Company's financial statements to remove an acquisition adjustment, contributions from customers and assets not subject to regulation, as discussed below. As of December 31, 2024, these amounts totaled $6,127,000 in Plant cost and $4,030,000 in Accumulated depreciation. In addition, accumulated deferred income taxes,

cash working capital allowance and other rate base components were computed. The computation of the rate base is presented on Schedule C1-5.

Fourth, the required Net Utility Operating Income was developed using the FPFTY costs and rate base. To produce the required to return of 8.27%, Valley is proposing FPFTY revenue of $8,109,000 (plus $24,000 Other revenue, for total revenue of $8,133,000) (excluding Other revenue), an increase of $1,626,000. This amount is an increase of 25.1% in total Distribution revenue and an increase of 29.6% excluding customers being served under long-term contracts (and not subject to these increases).

Finally, proposed rates were developed that produce the required FPFTY revenue for each rate class. The Company is proposing a uniform percentage increase in revenue for classes whose rates are subject to change (*i.e.* all non-contract customers). Schedule B4-2 shows that the proposed rates produce the revenue target for each class. Schedule B5 summarizes current rates and proposed rates; the amounts that ratepayers with different usage levels will pay under the current and proposed rates are presented on Schedule B5-1 (including the Gas Cost Rate ("GCR")) and Schedule B5-2 (excluding the GCR).

Q. What are the reasons that Valley needs an increase in rates at this time?

A. Schedule C1-6 presents the financial drivers for the requested rate increase by comparing the FPFTY to the final results of Valley's prior rate case, Docket R-2022-3032300. As the Schedule shows, Valley's requested rate increase is driven primarily by cost increases and new utility plant. The Company's corporate witnesses explain the cost increases and utility plant investments that are included in the proposed rates, as well as cost mitigation efforts.

Q. What service classifications does Valley use to report sales and revenue?

A. Valley reports sales and revenue using the following service classifications:

Customer Type	Rate Schedule
Residential	• Rate R- Residential
Commercial and Industrial Sales	• Rate C- Commercial • Rate IS- Interruptible Service • Rate SI- Small Industrial
Transportation	• Transport Firm • Transport- Contract • Transport Firm- DDQ • Rate I- Large Industrial Firm • Transport- Interruptible

Q. Are any changes being proposed to these service classifications?

A. No.

Q. What types of charges are in the Tariff?

A. Rate R is a firm sales class that includes a monthly customer charge and a volumetric charge for distribution, and the volumetric "GCR".

Rate C is a firm sales class for commercial customers that includes a monthly customer charge and a volumetric charge for distribution, and the GCR. Transport Firm- DDQ has the same monthly customer charge and volumetric charge for distribution as Rate C, and no GCR.

Rate I is a firm sales class for industrial customers that includes a blocked volumetric charge for distribution, a blocked charge for demand and the GCR. Rate I is available when and where the Company's facilities are adequate and suitable for the customer's requirements. As explained below, the Company is proposing to revise the rate design for this offering.

Rate IS is an interruptible class that includes a monthly customer charge and a volumetric charge for distribution, and the GCR. Transport- Interruptible has the same monthly customer charge and volumetric charge for distribution as Rate IS, and no GCR.

Rate SI is a firm sales class that includes a monthly customer charge and a volumetric charge for distribution, and the GCR. Transport- Firm has the same monthly customer charge and volumetric charge for distribution as Rate SI, and no GCR.

Transport- Contract customers are served under their applicable contract terms, which can include a flat monthly charge and/or blocked volumetric distribution rates. All customers are billed monthly.

Q. Why is the Company proposing a uniform percentage increase in revenue for non-contract classes?

A. A uniform increase in revenue is appropriate because:

- The composition of ccf sales is stable. In the HTY, FTY and FPFTY, residential deliveries are 15%-17% of the total deliveries, commercial and industrial classes are 7%-9%, and transportation classes are 74%-77%.
- A uniform rate increase is the simplest to implement, and Valley management believes it would be the most acceptable to ratepayers.
- A class cost of service study would be expensive and time-consuming.

Q. Is the Company proposing any rate design changes?

A. Yes, the Company is proposing changes for Rate I, which are discussed in more detail later in my testimony.

HTY SALES AND REVENUE AND HTY COSTS

Q. Please identify and describe the exhibits that show HTY sales and revenue.

A. Schedule B shows Valley's total rate revenue for HTY 2024, and distribution-only revenue for HTY 2024, FTY 2025 and FPFTY 2026.

HTY total operating revenue is $10,005,000 based on Valley's financial statements (Schedule B1-2, line 18). Total rate case revenue is $8,531,000 (Schedule B1-2, lines 10 and 18), which *excludes* timing differences for GCR over / undercollection and Unbilled revenue, rounding differences in computation, the State Tax Adjustment (STAS) and a cost recovery item which is excluded from regulated rates. The HTY Distribution-only amounts are from Schedule B1, which is supported by the detailed computations on Schedule B1-1, using present rates and HTY deliveries in ccf, and number of customer bills.

Pursuant to Rate Schedule T, Valley is providing transportation contract service to a customer referenced here as "Customer A" using assets constructed and operated at the request of the customer. The amount included in HTY distribution revenue in this rate case is the contract revenue applicable to providing transportation service only, exclusive of reimbursements for construction of the assets serving Customer A. In addition, the capital costs related to the assets used to serve Customer A, and the related accumulated depreciation are not included in the rate base;furthermore, the related depreciation expense is not included in the revenue requirement.

Q. Please describe the HTY information regarding costs.

A. Schedule C1-1 shows operating costs by account for the HTY. This exhibit is described in detail later in my testimony. The costs are carried forward to Schedule C1.

Q. Please describe the HTY information regarding rate base and Rate of Return.

A. Schedule C1-5 computes the rate base for the HTY. Schedule C1 shows the return on rate base for the HTY was 4.30% for Distribution-only.

FTY AND FPFTY SALES AND REVENUE

Q. Please identify and describe the exhibits that show FTY and FPFTY sales and revenue at present rates.

A. Information on sales and revenue is presented in Schedule B. Information for HTY is on Schedule B1, with computations on Schedule B1-1. Deliveries in HTY totaled approximately 32.9 million ccf.

The FTY and FPFTY forecasts of delivery volumes were developed as discussed below.

Rate R - This class consists of full-service (sales plus transportation) customers taking service under Rate R. The monthly use per customer was developed based on a regression analysis using number of customers and sales data for 2016-2024, and Heating Degree Days ("HDD"). The R-square was 94.7%, indicating that HDDs explain 94.7% of the variation in monthly usage per customer. The regression results were applied to the weather-normal monthly HDD, and to the forecast number of customers (including 50 new customers in 2025 and 50 additional new customers in 2026), to forecast deliveries for FTY and FPFTY. The "weather-normal monthly HDD" are the monthly averages for July 2015 through December 2024.

Rate C - This class consists of full-service customers taking service under Rate C. The monthly use per customer was developed based on a regression analysis, using sales data for 2016-2024. The R-square was 94.0%. The regression results were applied to the weather-normal monthly HDD, and to the forecast number of customers, to determine forecast deliveries for the FTY and FPFTY.

Rate IS - This class consists of full-service customers taking interruptible service under Rate IS. The monthly use per customer was developed based on a regression analysis, using sales data for 2019-2024. This period was chosen because the R-squares for longer periods were not as good as for this period (*i.e.* correlation was lower). The R-square was 65.5%. The relationship between HDD and usage per customer is not as strong as for Rate R and Rate C, which is expected for an Interruptible class. The regression results were applied to the weather-normal monthly HDD, and to the forecast number of customers, to determine forecast deliveries for the FTY and FPFTY.

Rate SI - This class consists of full-service customers taking interruptible service under Rate SI. The monthly use per customer was developed based on a regression analysis, using data for 2016-2024. The R-square was 72.8%. The regression results were applied to the weather-normal monthly HDD, and to the forecast number of customers, to determine forecast deliveries for the FTY and FPFTY.

Transport Firm - This class consists of transportation-only customers, with two customer types:

- *Customers taking transportation-only service under Rate SI*. The monthly use was developed based on a regression analysis, using data for 2018-2024. In addition, Customer Z's customer's data was removed from the analysis (see below regarding Rate I). The R-square was 4.8%. The regression results were applied to weather-normal monthly HDD, to determine forecast deliveries for the FTY and FPFTY. While the R-square correlation is very weak, it results in almost the same forecast ccf for FTY and FPFTY as using a simple average, therefore the regression results were deemed acceptable.

- *Customers taking transportation-only service pursuant to contracts*. These are two such customers in the Company' service territory. The monthly use for each customer was developed based on a regression analysis, using data for 2018-2024. The regression determined the R-squares were 54.1% and 68.7%. While HDD explains a meaningful portion of the variation, other factors also affect usage, therefore the regressions were accepted as reasonable. The regression results were applied to the weather-normal monthly HDD, to determine forecast deliveries for each customer for FTY and FPFTY.

Transport DDQ - This class includes transportation-only customers taking service under Rate C. The monthly use per customer was developed based on a regression analysis, using data for same period as for Rate R. The R-square was 92.0%. The regression results were applied to the weather-normal monthly HDD and to the forecast number of customers to determine forecast deliveries for the FTY and FPFTY.

Transport Interruptible - This class includes transportation-only customers taking service under Rate IS. The monthly use per customer was developed based on a regression analysis, using data for 2016-2024. In addition, Customer Z's customer's data was removed from the analysis (see below regarding Rate I). The R-square was 44.3%. The relationship between HDD and usage per customer is not as strong as for Rate R and Rate C, which is expected for an Interruptible class. The regression results were applied to the weather-normal monthly HDD, and to the forecast number of customers, to determine forecast deliveries for the FTY and FPFTY.

Rate I - This class includes transportation-only customers taking service under Rate I, Large Industrial Firm. This class had no customers in the recent past, however a customer

("Customer Z") that had been taking service under two other rates is migrating to Rate I in 2025. Customer Z's monthly usage was removed from the other two classes, and included in Rate I. for this purpose. The monthly use was developed based on a regression analysis, using data for 2019-2024. The R-square was 59.3%. The regression results were applied to the weather-normal monthly HDD, and to the forecast number of customers, to determine forecast deliveries for the FTY and FPFTY.

The table below summarizes the results of the sales forecast.

Rate Class/ Level of Service	Customers FPFTY 2026	CCF FPFTY 2026	Customers HTY 2024	CCF HTY 2024	R-squared
R- Full service	6,586	5,886,309	6,486	5,020,399	94.7%
C- Full service	851	2,566,623	854	2,258,909	94.0%
IS- Full service	1	222,000	1	251,560	65.5%
SI- Full service	4	59,459	4	57,691	72.8%
Trans Firm	13	17,528,029	13	16,709,307	4.8%/ 54.1% 68.7%/
Trans DDQ(C)	56	947,972	56	975,293	92.0%
Rate I	1	3,581,019	1	3,643,460	59.3%
Trans Interr(IS)	4	4,139,558	5	4,031,939	44.3%
Total	**7,516**	**34,930,969**	**7,420**	**32,948,558**	
HDD		6,393		5,643	

FTY AND FPFTY COSTS

Q. Please identify the schedules that present Valley's costs.

A. Schedule C1 presents a summary of all costs for the HTY, Distribution-only costs for the HTY and Distribution-only costs for the FTY and FPFTY. Schedule C1-1 presents operating costs, detailed by account. Schedule C3 presents the computation of depreciation expense. Schedule C1-3 presents the computation of Taxes other than income. Rate case expense and Income tax expense, and adjustments to reflect costs to be unbundled from distribution rates and recovered in the GCR rate, are discussed below.

Q. How did you develop the FTY and FPFTY operating costs?

A. Schedule C1-1 presents operating costs for HTY 2024, FTY 2025 and FPFTY 2026, detailed by account. Total operating costs for the HTY 2024, excluding Purchased Gas, were $3,654,000 (line 48).

The totals for Distribution O&M, Customer accounting and Administrative and General ("A&G") are carried forward to Schedule C1, lines 11, 12 and 14 respectively. Costs are also summarized by type- Labor, Transportation, Material, Overhead and Other (Schedule C1-1, lines 50-55).

Q. How did you compute Depreciation expense for FTY and FPFTY?

A. Schedule C3, pages 1-3, shows the asset values at original cost in PAPUC/FERC account detail as of December 31, 2024, and planned additions and removals for the FTY and FPFTY. Schedule C3, page 2, shows the depreciation rate applicable to each account, and depreciation expense for HTY, FTY and FPFTY. Depreciation expense for each account for the FTY and the FPFTY was computed by multiplying X), the depreciation rate for the account, times Y), original cost at the prior year end, plus one-half of additions for the year. The total FPFTY depreciation expense, less amounts charged to operating costs (and included on Schedule C1-1), is $1,543,000 (line 39); this amount is carried forward to Schedule C1, line 17.

Q. What adjustments were made to plant amounts in Valley's financial statements?

A. Two adjustments were made. First, Gas Plant Acquisition costs, shown on Schedule C3, line 2, were removed from plant costs (line 36). Second, costs incurred to serve Customer A were removed from lines 3-5, in accordance with the Commission's approval of the service arrangement for this customer at Docket No. A-2012-2335954, which states that

all such costs would be paid by Customer A. In both cases, the corresponding accumulated depreciation was also removed. This is consistent with how these costs were addressed, without objection from any party, in Valley's last rate case.

Q. How did you compute Taxes other than income for FTY 2025 and FPFTY 2026?

A. Schedule C1-3 shows Taxes other than income, which comprises the Pennsylvania Use Tax and the Public Utility Realty Tax and the PUC Assessment. The Utility Realty Tax is assumed to change in relation to Net plant. Pennsylvania Use Tax is assumed to remain the same as for the HTY. The total is carried forward to Schedule C1, line 18.

Q. How did you compute the FPFTY Rate case expense amortization?

A. The Rate case expense amortization reflects the normalized rate case expense. Expenses for the pending rate case, if fully litigated, are estimated at $277,000 and a three-year normalization period was determined to be reasonable, starting January 1, 2026 (the start of the FPFTY). The elements of Valley's rate case expense are shown on Schedule C1-3, lines 10-18 and the result is carried forward to Schedule C1, line 13.

Q. How did you compute the FTY and FPFTY Income tax expense?

A. Income tax expense for the FTY and FPFTY is computed on Schedule C1-4.

Operating Income (Loss) before Income Tax (line 1), is from Schedule C1, line 22.

Synchronized interest expense (lines 4-9) is computed by multiplying rate base (Schedule C1, line 27) multiplying by weighted cost of debt (Schedule C1-2).

Taxable income before depreciation tax adjustments (line 10) is equal to Operating Income (Loss) Income Tax (line 1) less Synchronized interest expense (line 9).

Regulatory Pennsylvania taxable income and Regulatory Pennsylvania tax expense are computed using the Full flow through method; that is, tax depreciation is used in the

computation. The Pennsylvania depreciation adjustment (lines 12-15) reflects the depreciation expense on Valley's Pennsylvania tax return and is computed using the double declining balance method applied to tax basis and tax life (just as on the tax return). Regulatory Pennsylvania taxable income (line 16) is equal to Taxable income before depreciation tax adjustments as adjusted by the Pennsylvania depreciation adjustment. Regulatory Pennsylvania income tax expense (line 17) is equal to Regulatory Pennsylvania taxable income times the statutory 9.99% rate.

Regulatory Federal taxable income and Regulatory Federal tax expense are computed using a modified Full flow through method; that is, a modified tax depreciation amount is used in the computation. The Federal depreciation adjustment (lines 19-22), reflects straight line depreciation applied to tax basis and tax life. Federal taxable income (line 27) is equal to Taxable income before depreciation tax adjustments as adjusted by the Federal depreciation adjustment and less Regulatory Pennsylvania tax expense. Regulatory Federal income tax (line 28) is equal to Regulatory Federal taxable income times the statutory 21% rate.

Regulatory total income tax expense (line 29) is equal to Regulatory Pennsylvania income tax expense plus Regulatory Federal income tax expense, and is carried forward to Schedule C1, line 24.

Q. Does the computation of income tax expense included in the revenue requirement comply with Act No. 40 of 2016, which amends the Public Utility Code regarding the treatment of income tax expense for ratemaking purposes?

A. Yes. The computation of income tax expense for ratemaking purposes, presented on Schedule C1-4 (i.e., in the revenue requirement), reflects a tax deduction for each item of

expense (e.g., depreciation expense) in the revenue requirement. In addition, there are no items that reduce the income tax expense for ratemaking purposes, or increase the deferred tax liability, other than those reflected in the revenue requirement.

Q. Did you compute the Net Utility Operating Income and Return on Rate Base at present rates?

A. Yes. Schedule C1, line 25 shows Net Utility Operating Income at Present Rates for the HTY, FTY and FPFTY. Schedule C1, line 28 shows Return on Rate Base for Distribution-only at present rates of 4.30% for HTY, 5.29% for FTY and 3.72% for FPFTY.

RATE BASE FOR THE FTY AND FPFTY

Q. How did you develop the Rate Base?

A. The Rate Base at the end of the HTY, FTY and FPFTY is presented in Schedule C1-5. Assets at original cost and accumulated depreciation are carried forward from Schedule C3. Schedule C3 shows assets at original cost at the end of the HTY (December 31, 2024) and adds forecast capital expenditures to compute assets at the end of the FTY (December 31, 2025) and the FPFTY (December 31, 2026). As described above, annual depreciation expense for each account is computed by multiplying X) the depreciation rate for the account times Y) original cost at the prior year end plus one-half of additions for the year. Accumulated depreciation at each year-end is computed by adding annual depreciation expense, and subtracting retirements, to the previous year-end balance.

The amounts for Customer deposits and Materials and supplies, are the amounts on Valley's Balance Sheets at December 31, 2024, presented in Schedule C2. Each of these items was estimated to be the same for the FTY and the FPFTY as for the HTY.

Natural Gas Inventories (Schedule C1-5, line 8) is the average monthly volume over the period 2014-2024, times the currently effective GCR rate. This amount is unbundled from distribution rates and recovered in the GCR, and therefore not included in rate base.

The rate base includes a reduction for Accumulated Deferred Income Taxes ("ADIT"), equal to the difference between Accumulated depreciation based on X) Federal tax expense borne by ratepayers (i.e., based on straight line method discussed above) and Y) Valley's actual Federal tax expense (i.e., based on double declining balance method), times the current Federal income tax rate. The ADIT is computed on Schedule C1-5, lines 26-31 and carried up line 6.

The rate base includes a reduction for Accrued Pension / OPEB liability, reflecting the excess of amounts charged to expense over amounts paid in case (Schedule C1-5, lines 34-32, carried up to line 10).

Cash Working Capital was determined by using the widely-accepted formula of 1/8 of non-fuel cash operating costs (Schedule C1-5, lines 16-24, carried up to line 13).

The total Rate Base, Schedule C1-5, line 14, is carried forward to Schedule C1, line 27.

NET UTILITY OPERATING INCOME

Q. What is the distribution revenue requirement for the FPFTY?

A. FPFTY forecast revenue at present rates (including Other revenue) is $6,507,000. The FPFTY revenue required to produce Mr. D'Ascendis and Mr. Kucan's recommended rate of return of 8.27% is $8,133,000. Valley is requesting a revenue increase of $1,626,000 (Schedule C1, line 7).

Q. What revenue is included in the Distribution revenue requirement?

A. The total revenue requirement includes:

- Gas delivery revenue: Revenue from delivery of gas, for both sales and transportation customers, including contract and non-contract customers.
- Other revenue: Primarily Forfeited Discounts (late payment charges).

Unbilled Revenue is not included because FPFTY sales are normalized.

Q. What rate of return on rate base do Mr. D'Ascendis and Mr. Kucan recommend?

A. Mr. D'Ascendis and Mr. Kucan recommend a return on rate base of 8.27%.

Q. What rate of return on rate base do the proposed rates produce?

A. Valley's proposed rates produce FPFTY Distribution revenue of $8,109,000 (excluding Other revenue), Net Operating Income of $2,083,000 and rate of return of 8.27%, on rate base (Schedule C1).

PROPOSED RATES

Q. How were the proposed rates developed?

A. A revenue target was established for each class (other than contract transportation customers) by increasing revenue at present rates by 29.56%. The proposed fixed monthly charges are based on comparisons to those charged by other Pennsylvania utilities, and represent increases of approximately 14% for Residential and small Commercial customers, and approximately 22% for most other customers (Schedule B4-2, lines 27-28). For each class, the balance of the revenue target was recovered by changing volumetric or demand rates. The current rates and proposed rates are shown in Schedule B5.

Q. Is the Company proposing any rate design changes?

A. Valley is proposing to revise the rate design for Rate I to promote conservation, to better reflect cost of service and to simplify the rate. Specifically, Valley is proposing to add a monthly customer charge and to combine the 2nd and 3rd blocks of the volumetric commodity charge per Ccf.

Q. Did you compare the amounts that customers in each rate class would pay under the present and proposed rates?

A. Yes. Schedule B5-1 compares the amounts that customers in each rate class with a range of usage levels would pay in the FPFTY, both at present rates and the proposed rates, including the GCR. Schedule B5-2 shows the comparison excluding the GCR and is therefore applicable to transportation customers.

Q. Did you prepare a schedule showing the number of customers whose bills would increase under the proposed rates?

A. Yes. Schedule B3 presents that information.

Q. Do the proposed rates produce the required revenue?

A. Yes. Schedule B4-2 computes the distribution revenue that would be produced by the proposed rates. Line 22 shows that the revenue produced by the proposed rates is $8,109,000, representing an increase of $1,626,000, producing a return of 8.27%.

Q. Does this conclude your Direct Testimony?

A. Yes.

BEFORE

THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	**:**	
	:	
v.	**:**	**Docket No. R-2022-_____**
	:	
Valley Energy, Inc.:	**:**	

EXHIBITS

OF

HOWARD S. GORMAN

ON BEHALF OF

VALLEY ENERGY, INC.

APRIL 30, 2025

RESUME OF
HOWARD S. GORMAN

SUMMARY

Mr. Gorman has more than 35 years of experience in the energy industry, including 25 years in rate and regulatory proceedings. His areas of expertise include embedded class cost of service studies, marginal cost studies, revenue allocation, rate design and revenue requirements, for both electric and gas utilities. He has testified as an expert witness before the Massachusetts Department of Public Utilities, New Hampshire Public Utilities Commission, New Jersey Board of Public Utilities, New York State Public Service Commission, Ontario Energy Board, Pennsylvania Public Utility Commission and Rhode Island Public Utilities Commission. Mr. Gorman also has experience in financial modeling, financial analysis and forecasting and treasury and financial management.

PROFESSIONAL EMPLOYMENT

2010 - Present	HSG Group, Inc. • *President*
1997 - 2010	Black & Veatch Corporation (R.J. Rudden Associates, Inc. before 2005) • *Principal Consultant*
1995 - 1997	Independent Consultant
1987 – 1995	Trigen Energy Corporation • 1987-1993- *Corporate Controller; Trigen was formed in 1987* • 1993-1995- *Treasurer; Trigen had IPO with NYSE listing in 1994*
1982 - 1987	Coleco Industries, Inc. • *Director, Treasury*
1976 - 1979	Touche Ross & Co. • *Staff Accountant*

PROFESSIONAL EXPERIENCE

Utility Accounting and Costing

Mr. Gorman has performed numerous class cost of service studies, and has developed and supported revenue requirements, revenue allocation, rate designs and marginal cost studies, in rate cases before regulatory commissions in several jurisdictions, for electric and gas utilities. These assignments included developing test year data and rate year forecasts, establishing cost causality, selecting and developing allocators and analyzing customer impacts and policy considerations

Energy Project Analysis and Financing

Mr. Gorman has negotiated and completed transactions including construction and term loans, tax-exempt bonds, taxable bonds, subordinated debt and asset-backed (receivables and inventory) revolving credit facilities. He has worked successfully with lenders and borrowers to source and structure transactions, and was instrumental in negotiating loan documents and in designing power sale and supply procurement contracts to be financed. Mr. Gorman has performed financial analyses of energy-related assets, including electric and gas distribution companies, power plants and transmission operators. These analyses included development of cash flows and financial statements based on both regulatory and accounting presentations, and included review of assumptions, analysis of data, modeling and forecasting, sensitivity testing and stress testing.

Accounting and Financial Management

As controller of Trigen Energy Corporation, Mr. Gorman built the finance and accounting function; developed reports, procedures and management tools; and managed subsidiary controllers across North America, including an IPO with NYSE listing. He managed the corporate insurance portfolios and the benefit plans for Trigen Energy Corporation and for Coleco Industries, and has managed interest rate and currency forward contracts for the purpose of managing risk.

Publications And Presentations

"What Wall Street Needs From FERC," published in R. J. Rudden Financial, LLC's *Energy Capital Markets Report*, September 2002

"A Balanced Look at Balance Sheets," published in R.J. Rudden Financial, LLC's *Energy Capital Markets Report,* June 2002

"Assessment of Retail Choice Programs," presented at the American Gas Association Rate and Strategic Issues Committee Conference, March 2002

"The Remarkable Story on Enron," published in Scudder's *Annual End of Year Issue*, 2001

Education

New York University, B.S., Accounting, 1976
Harvard Business School, MBA, 1981

Relevant Projects			
Jurisdiction	**Docket**	**Client**	**Subject Matter**
Federal Energy Regulatory Commission 2024	ER24-2795-000, ER24-2796-000	Massachusetts / Nantucket Electric	Electric revenue requirement and rate design for Energy Storage Systems
New York 2024	24-E-0322	Niagara Mohawk (Gas)	Gas class cost of service; revenue allocation; rate design; marginal cost
New York 2024	24-G-0323	Niagara Mohawk (Electric)	Electric class cost of service; revenue allocation; rate design; marginal cost
Pennsylvania 2024	R-2024-3046523	Duquesne Light	Electric class cost of service; revenue allocation; rate design; special study
Massachusetts 2023	DPU 23-150	Massachusetts / Nantucket Electric	Electric class cost of service; revenue allocation; rate design
New Jersey 2024	GR24020158	Elizabethtown Gas.	Gas class cost of service; revenue allocation; rate design
Massachusetts 2023	DPU 23-150	Massachusetts / Nantucket Electric	Electric class cost of service; revenue allocation; rate design
New York 2023	23-G-0227	Valley Energy, Inc.	Gas revenue requirements, rate design
New York 2023	23-G-0225 /02260	Brooklyn Union Gas / KeySpan Gas East	Gas class cost of service; revenue allocation; rate design; marginal cost
Pennsylvania 2022	R-2022-3032369	Citizens' Electric of Lewisburg, PA	Electric revenue requirements, class cost of service, revenue allocation, rate design
Pennsylvania 2022	R-2022-3032300	Valley Energy, Inc.	Gas revenue requirements, rate design
Pennsylvania 2021	R-2021-3024060	Vicinity Energy Philadelphia	Steam system revenue requirements; sales forecast (formerly Veolia)
Pennsylvania 2021	R-2021-3024750	Duquesne Light	Electric class cost of service; revenue allocation; rate design
New York 2020	20-G-0381	Niagara Mohawk (Gas)	Gas class cost of service; revenue allocation; rate design; marginal cost
New York 2020	20-E-0380	Niagara Mohawk (Electric)	Electric class cost of service; revenue allocation; rate design; marginal cost
Pennsylvania 2019	R-2019-3008212	Citizens' Electric of Lewisburg, PA	Electric revenue requirements, class cost of service, revenue allocation, rate design
Pennsylvania 2019	R-2019-3008208	Wellsboro Electric Company	Electric revenue requirements, class cost of service, revenue allocation, rate design
Pennsylvania 2019	R-2019-3008209	Valley Energy, Inc.	Gas revenue requirements, rate design
New York 2019	19-G-0309 /0310	Brooklyn Union Gas / KeySpan Gas East	Gas class cost of service; revenue allocation; rate design; marginal cost
Massachusetts 2018	DPU 18-150	Massachusetts / Nantucket Electric	Electric class cost of service; revenue allocation; rate design; marginal cost Monthly Minimum Reliability Contribution
Pennsylvania 2018	R-2018-30000124	Duquesne Light	Electric class cost of service; revenue allocation; rate design

Relevant Projects			
Rhode Island 2017	RIPUC 4770	Narragansett Electric	Electric class cost of service; revenue allocation; rate design
Pennsylvania 2017	R-2017-2593142	Veolia Energy Philadelphia	Steam system revenue requirements; sales forecast
New York 2017	17-G-0239	Niagara Mohawk (Gas)	Gas class cost of service; revenue allocation; rate design; marginal cost
New York 2017	17-E-0238	Niagara Mohawk (Electric)	Electric class cost of service; revenue allocation; rate design; marginal cost
Pennsylvania 2016	R-2016-2531550	Citizens' Electric of Lewisburg, PA	Electric revenue requirements, class cost of service, revenue allocation, rate design
Pennsylvania 2016	R-2016-2531551	Wellsboro Electric Company	Electric revenue requirements, class cost of service, revenue allocation, rate design
New Hampshire 2016	DE 16-383	Granite State Electric	Electric revenue requirement
New York 2016	16-G-0058 /0059	Brooklyn Union Gas / KeySpan Gas East	Gas class cost of service; revenue allocation; rate design; marginal cost
Massachusetts 2015	DPU 15-155	Massachusetts / Nantucket Electric	Marginal cost
New York 2015	15-E-0184	Jamestown Board of Public Utilities	Electric revenue requirements
New Hampshire 2015	DE14-180	Energy North Natural Gas	Gas revenue requirements
New York 2014	14-E-0035	Village of Freeport	Electric revenue requirements; sales forecast; rate design
Pennsylvania 2014	R-2013-2386293	Veolia Energy Philadelphia	Steam system revenue requirements and sales forecast
Pennsylvania 2014	R-2013-2372129	Duquesne Light	Electric class cost of service; revenue allocation; rate design
New Hampshire 2013	DE13-063	Granite State Electric	Electric class cost of service (marginal cost); revenue allocation; rate design
Ontario 2013, 2012, 2010, 2009, 2008, 2006, 2005	EB-2005-0378 et al	Hydro One Networks Inc.	Electric Transmission and Distribution cost allocation; OH capitalization rates
Ontario 2006-2013	EB-2007-0905 et al	Ontario Power Generation	Electric cost allocation methodology (2013, 2010, 2006)
New York 2012	12-E-0201	Niagara Mohawk (Electric)	Electric class cost of service; revenue allocation
Rhode Island 2012	RIPUC 4323	Narragansett Electric	Electric class cost of service
New York 2011	11-E-0590	Village of Rockville Centre	Electric revenue requirements; rate design; sales forecast
New York 2011	11-G-0142	Chautauqua Utilities, Inc.	Gas revenue requirements, rate design
Pennsylvania 2010	R-2010-2179522	Duquesne Light	Electric class cost of service; revenue allocation; rate design

Relevant Projects			
Pennsylvania 2010	R-2010-2172662	Wellsboro Electric	Electric revenue requirements, class cost of service, revenue allocation, rate design
Pennsylvania 2010	R-2010-2172665	Citizens' Electric of Lewisburg, PA	Electric revenue requirements, class cost of service, revenue allocation, rate design
Pennsylvania 2010	R-2010-2174470	Valley Energy, Inc.	Gas revenue requirements, rate design
Pennsylvania 2010	R-2010-2161592	PECO Energy (Gas)	Gas class cost of service; revenue allocation; rate design
Pennsylvania 2010	R-2010-2161575	PECO Energy (Electric)	Electric class cost of service; revenue allocation; rate design
New York 2010	10-E-0050	Niagara Mohawk (Electric)	Electric class cost of service
New York 2009	09-E-0862	Jamestown Board of Public Utilities	Electric revenue requirements
Pennsylvania 2009, 2006, 2002, 2001	R-2139884 R-00061931 M-00021612 R- 00017034 R- 00006042	Philadelphia Gas Works	Gas class cost of service; revenue allocation; rate design; unbundling; fixed costs recovery
Rhode Island 2009	RIPUC 4065	Narragansett Electric	Electric class cost of service; revenue allocation; rate design
Massachusetts 2009	DPU 09-39	Massachusetts / Nantucket Electric	Electric revenue requirements; class cost of service; revenue allocation; rate design
Pennsylvania 2008	R-2008-2028394	PECO Energy (Gas)	Gas class cost of service; revenue allocation; rate design
Pennsylvania 2007	R-00072350	Wellsboro Electric	Electric revenue requirements; rate design
Pennsylvania 2007	R-00072348	Citizens' Electric of Lewisburg, PA	Electric revenue requirements; rate design
Pennsylvania 2007	R-00072349	Valley Energy, Inc.	Gas revenue requirements; rate design
New York 2006	06-E-0911	Village of Freeport	Electric revenue requirements; rate design
Pennsylvania 2006	R-00061346	Duquesne Light	Electric class cost of service; revenue allocation; rate design
New York 2003	03-E-1568	Village of Rockville Centre	Electric revenue requirements; rate design; sales forecast
New Jersey 2002	ER02080506, ER02050303 et al	AmeriSteel (intervenor)	Electric cost allocation and rate design; industrial rates

Valley Energy, Inc. (PA)
Rate Case with Fully Projected Future Test Year 2026
INDEX TO SCHEDULES

Line	SCHEDULE	DESCRIPTION	PERIOD
1	A	INDEX TO SCHEDULES	
2			
3		**RATES AND REVENUE**	
4	B	Operating Revenue Under Present Rates and Proposed Rates	Years Ended 12/31/2024, 12/31/2025 and 12/31/2026
5	B1	Summary Of Sales, Customers And Revenue At Present Rates	Historic Year December 31, 2024
6	B1-1	Billing Units, Rates And Revenue At Present Rates	Historic Year December 31, 2024
7	B1-2	Bill Analysis- Revenues Under Present Rates	Historic Year December 31, 2024
8	B2	Summary Of Sales, Customers And Revenue At Present Rates	Future Test Year December 31, 2025
9	B2-1	Billing Units, Rates And Revenue At Present Rates	Future Test Year December 31, 2025
10	B3	Number of Customers Served Whose Bills Will be Increased	Years Ended 12/31/2024, 12/31/2025 and 12/31/2026
11	B4	Summary Of Sales, Customers And Revenue At Present and Proposed Rates	Fully Projected Future Test Year December 31, 2026
12	B4-1	Billing Units, Rates And Revenue At PRESENT Rates	Fully Projected Future Test Year December 31, 2026
13	B4-2	Billing Units, Rates And Revenue At PROPOSED Rates	Fully Projected Future Test Year December 31, 2026
14			
15		**TARIFF RATES**	
16	B5	Summary Of Present And Proposed Tariff Rates	Historic Year December 31, 2024 and Fully Projected Future Test Year December 31, 2026
17	B5-1	Bill Comparisons (including GCR present rate)	Fully Projected Future Test Year December 31, 2026
18	B5-2	Bill Comparisons (excluding GCR)	Fully Projected Future Test Year December 31, 2026
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20		**NET OPERATING INCOME AND RATES OF RETURN**	
21	C1	Net Operating Income And Rates of Return	Years Ended 12/31/2024, 12/31/2025 and 12/31/2026
22	C1-1	Support Sheet No. 1- Operating Expense and Going-Level Adjustments	Years Ended 12/31/2024, 12/31/2025 and 12/31/2026
23	C1-2	Support Sheet No. 2- Summary of Cost of Capital and Fair Rate of Return Based upon a Hypothetical Ratemaking Capital Structure	12/31/2026
24	C1-3	Support Sheet No. 3- Taxes Other Than Income	Years Ended 12/31/2024, 12/31/2025 and 12/31/2026
25	C1-4	Support Sheet No. 4- Income Tax Calculations	Years Ended 12/31/2024, 12/31/2025 and 12/31/2026
26	C1-5	Support Sheet No. 5- Computation of Rate Base	Years Ended 12/31/2024, 12/31/2025 and 12/31/2026
27	C1-8	Comparison to Prior Rate Case	Prior Rate Case and Fully Projected Future Test Year December 31, 2026
28	C2	Balance Sheets	Years Ended 12/31/2024, 12/31/2025 and 12/31/2026
29	C3	Original Cost of Utility Plant in Service	Years Ended 12/31/2024, 12/31/2025 and 12/31/2026
30			
31		**WORKPAPERS**	
32	WP	Workpapers	See separate index

B

Valley Energy, Inc. (PA)
Rate Case with Fully Projected Future Test Year 2026

Operating Revenue Under Present Rates and Proposed Rates
Years Ended 12/31/2024, 12/31/2025 and 12/31/2026
Answer to 52 Pa. Code 53.52 b[4]

Line	Operating Revenues	Historic Year December 31, 2024		PRESENT RATES Future Test Year December 31, 2025	PRESENT RATES Fully Projected Future Test Year December 31, 2026	PROPOSED RATES Fully Projected Future Test Year December 31, 2026
		Per Books	Distribution Only	Distribution Only	Distribution Only	Distribution Only
1	Residential sales	$4,526,671	$2,823,518	$3,135,633	3,159,547	4,093,545
2	Commercial and Industrial sales	1,764,263	893,396	976,270	976,270	1,256,761
3	Transportation	2,217,436	2,217,436	2,321,925	2,347,099	2,758,721
4	Subtotal	8,508,370	5,934,349	6,433,828	6,482,916	8,109,028
5						
6	Forfeited Discounts	15,894	15,894	15,894	15,894	15,894
7	Other operating revenue	3,360	3,360	3,360	3,360	3,360
8	Non-operating revenue	1,950	1,950	4,321	4,321	4,321
9	Total Operating Revenues	$8,529,574	$5,955,553	$6,457,402	$6,506,491	$8,132,602

B1

Valley Energy, Inc. (PA)
Rate Case with Fully Projected Future Test Year 2026

Summary Of Sales, Customers And Revenue At Present Rates
Historic Year December 31, 2024

Line	Rate Class	Volumes (ccf)	Customers	Revenue - Present Rates		
				Fixed Customer Charge	Variable Distribution-Commodity	Distribution Total
1	Residential Sales Customers					
2	Rate R- Residential	5,020,399	6,486	$961,201	$1,862,317	2,823,518
3						
4	Commercial and Industrial Sales Customers					
5	Rate C- Commercial	2,258,909	854	224,988	630,891	855,878
6	Rate IS- Interruptible Service	251,560	1	984	21,815	22,799
7	Rate SI- Small Industrial	57,691	4	3,936	10,782	14,718
8		2,568,160	859	229,908	663,488	893,396
9						
10	Transportation Customers					
11	Transport. Firm	2,581,397	12	11,808	482,463	494,271
12	Transport. Firm- Fixed	8,382,960	1	497,874		497,874
13	Transport. Firm- Volumetric	6,355,340	1		320,553	320,553
14	Transport. Firm- DDQ	975,293	56	14,750	272,390	287,140
15	Rate I - Large Industrial					
16	Transport. Interruptible	7,065,009	5	4,920	612,678	617,598
17		25,359,999	75	529,352	1,688,083	2,217,436
18						
19	TOTAL	32,948,558	7,420	$1,720,460	$4,213,889	$5,934,349

B1-1

Valley Energy, Inc. (PA)
Rate Case with Fully Projected Future Test Year 2026

Billing Units, Rates And Revenue At Present Rates
Historic Year December 31, 2024

Line	Description	Rate R- Residential	Rate C- Commercial	Rate IS- Interruptible Service	Rate SI- Small Industrial	Rate ST- Transport Firm	Rate I Large Industrial Firm	Transport Firm- Contract	Transport. Firm- DDQ	Transport. Interruptible	Total
1						**BILLING UNITS**					
2	ccf Sales	5,020,399	2,258,909	251,560	57,691	2,581,397		14,738,300	975,293	7,065,009	32,948,558
3											
4	Number of Bills	77,830	10,250	12	48	144		24	672	60	89,040
5	Average Monthly Bills	6,486	854	1	4	12		2	56	5	7,420
6											
7						**RATES AND CHARGES**					
8						**Tariff Rates**					
9	Customer Charge	$12.35	$21.95	$82.00	$82.00	$82.00		$0.00	$21.95	$82.00	
10								Contract-2			
11	Commodity Block 1	$0.37095	$0.279290	$0.086720	$0.186900	$0.186900		$0.0503	$0.279290	$0.086720	
12	Commodity Block 2							$0.0516			
13	Commodity Block 3										
14											
15	Demand Block 1										
16	Demand Block 2							Contract-1			
17	Fixed Monthly, Oct-Dec							$41,028	Thru 10/2024		
18	Fixed Monthly, Jan-Sep							$42,874	10/2024-09/2025		
19						**COMPUTATION OF REVENUE**					
20	Fixed Charge Revenue	961,201	224,988	984	3,936	11,808		497,874	14,750	4,920	1,720,460
21	Volumetric Revenue	1,862,317	630,891	21,815	10,782	482,463		320,553	272,390	612,678	4,213,889
22	**Total Distribution Revenue**	$2,823,518	$855,878	$22,799	$14,718	$494,271		$818,427	$287,140	$617,598	$5,934,349
23	*Check WP1_B*	*2,823,518*	*855,878*	*22,799*	*14,718*	*494,271*		*818,427*	*287,140*	*617,598*	*617,598*
24						**BILLING UNITS- DETAIL**					
25	ccf Sales	5,020,399	2,258,909	251,560	57,691	2,581,397	0	14,738,300	975,293	7,065,009	32,948,558
26											
27											

B1-2

Valley Energy, Inc. (PA)
Rate Case with Fully Projected Future Test Year 2026

Bill Analysis- Revenues Under Present Rates
Historic Year December 31, 2024

Line	Customer Type	Rate Case Amounts: Computed Delivery	Rate Case Amounts: Computed GCR	Rate Case Amounts: Other Revenue	Rate Case Amounts: Total for Rate Case	Unbilled, Reconciling Items and Other	Total Per Financials
1	Residential sales	$2,823,518	$1,703,154		$4,526,671		$4,526,671
2	Commercial and Industrial sales	893,396	870,867		1,764,263		1,764,263
3	Transportation	2,217,436			2,217,436		2,217,436
4	**Distribution Revenue**	5,934,349	2,574,021	0	8,508,370	0	8,508,370
5							
6	Forfeited Discounts			15,894	15,894		15,894
7	Other operating			3,360	3,360		3,360
8	Patronage Capital						
9	ISF Fees			1,950	1,950		1,950
10	**Total Revenue for Rate case**	**$5,934,349**	**$2,574,021**	**$21,204**	**$8,529,574**	**0**	**8,529,574**
11							
12	Prior Year E Factor Allocation					993,373	993,373
13	Over (Under) Gas					(174,685)	(174,685)
14	Residential Unbilled					104,925	104,925
15	Commercial Unbilled					34,975	34,975
16	Other Revenue					517,200	517,200
17	Rounding					(626)	(626)
18	**Total Operating Revenue per Financials**				**$8,529,574**	**$1,475,162**	**$10,004,736**
19						10,004,736	10,004,736

B2

Valley Energy, Inc. (PA)
Rate Case with Fully Projected Future Test Year 2026

Summary Of Sales, Customers And Revenue At Present Rates
Future Test Year December 31, 2025

Line	Rate Class	Volumes (ccf)	Customers	Revenue - Present Rates		
				Fixed Customer Charge	Variable Distribution-Commodity	Distribution Total
1	Residential Sales Customers					
2	Rate R- Residential	5,841,818	6,536	$968,611	$2,167,022	3,135,633
3						
4	Commercial and Industrial Sales Customers					
5	Rate C- Commercial	2,566,623	851	224,153	716,832	940,986
6	Rate IS- Interruptible Service	222,000	1	984	19,252	20,236
7	Rate SI- Small Industrial	59,459	4	3,936	11,113	15,049
8		2,848,082	856	229,073	747,197	976,270
9						
10	Transportation Customers					
11	Transport. Firm	1,881,944	11	10,824	351,735	362,559
12	Transport. Firm- Fixed	8,470,343	1	518,991		518,991
13	Transport. Firm- Volumetric	7,175,742	1		437,868	437,868
14	Transport. Firm- DDQ	947,972	56	14,750	264,759	279,509
15	Rate I - Large Industrial	3,581,019	1	0	360,079	360,079
16	Transport. Interruptible	4,139,559	4	3,936	358,983	362,919
17		26,196,578	74	548,501	1,773,423	2,321,925
18						
19	TOTAL	34,886,478	7,466	$1,746,185	$4,687,643	$6,433,828

B2-1

Valley Energy, Inc. (PA)
Rate Case with Fully Projected Future Test Year 2026

Billing Units, Rates And Revenue At Present Rates
Future Test Year December 31, 2025

Line	Description	Rate R- Residential	Rate C- Commercial	Rate IS- Interruptible Service	Rate SI- Small Industrial	Rate ST- Transport Firm	Rate I Large Industrial Firm	Transport Firm- Contract	Transport. Firm- DDQ	Transport. Interruptible	Total
1						**BILLING UNITS**					
2	ccf Sales- annualized	5,841,818	2,566,623	222,000	59,459	1,881,944	3,581,019	15,646,085	947,972	4,139,559	34,886,478
3											
4	Number of Bills	78,430	10,212	12	48	132	12	24	672	48	89,590
5	Number of Customers	6,536	851	1	4	11	1	2	56	4	7,466
6											
7						**RATES AND CHARGES**					
8						**Tariff Rates**					
9	Customer Charge	$12.35	$21.95	$82.00	$82.00	$82.00	$0.00	$0.00	$21.95	$82.00	
10								Contract-2			
11	Commodity Block 1	$0.37095	$0.27929	$0.08672	$0.18690	$0.18690	$0.14158	$0.0516	$0.279290	$0.08672	
12	Commodity Block 2						$0.08696	$0.0526			
13	Commodity Block 3						$0.05697				
14											
15	Demand Block 1						$1.55432				
16	Demand Block 2						$0.80660	Contract-1			
17	Fixed Monthly, Oct-Dec							$42,874	10/2024-09/2025		
18	Fixed Monthly, Jan-Sep							$44,375	10/2025-09/2026		
19						**COMPUTATION OF REVENUE**					
20	Fixed Charge Revenue	968,611	224,153	984	3,936	10,824		518,991	14,750	3,936	1,746,185
21	Volumetric Revenue	2,167,022	716,832	19,252	11,113	351,735	360,079	437,868	264,759	358,983	4,687,643
22	**Total Distribution Revenue**	$3,135,633	$940,986	$20,236	$15,049	$362,559	$360,079	$956,859	$279,509	$362,919	$6,433,828
23											
24						**BILLING UNITS- DETAIL**					
25	ccf Sales	5,841,818	2,566,623	222,000	59,459	1,881,944	3,581,019	15,646,085	947,972	4,139,559	34,886,478
26	Customers	6,536	851	1	4	11	1	2	56	4	7,466
27											
28											

B3

Valley Energy, Inc. (PA)
Rate Case with Fully Projected Future Test Year 2026

Number of Customers Served Whose Bills Will be Increased
Years Ended 12/31/2024, 12/31/2025 and 12/31/2026
Answer to 52 Pa. Code 53.52 b[3]

Line	Customer Type	Average Number of Customers During the Year		
		12/31/2024	12/31/2025	12/31/2026
1	Residential sales	6,486	6,536	6,586
2	Commercial and Industrial sales	859	856	856
3	Transportation	73	72	72
4	Customers with rates changing	7,418	7,464	7,514
5	Rates not changing	2	2	2
6	Total Customers Served	7,420	7,466	7,516
7				
8				
9				

B4

Valley Energy, Inc. (PA)
Rate Case with Fully Projected Future Test Year 2026

Summary Of Sales, Customers And Revenue At Present and Proposed Rates
Fully Projected Future Test Year December 31, 2026

				Revenue - Present Rates			Revenue - Proposed Rates					
Line	Rate Class	Sales (ccf)	Customers	Fixed Charge	Volumetric	Distribution Total	Fixed Charge	Volumetric	Distribution Total	Target Revenue	Proposed Increase	Proposed Increase %
1	Residential Sales Customers											
2	Rate R- Residential	5,886,309	6,586	$976,021	$2,183,526	3,159,547	$1,106,420	$2,987,125	4,093,545	4,093,531	933,998	29.56%
3												
4	Commercial and Industrial Sales Customers											
5	Rate C- Commercial	2,566,623	851	224,153	716,832	940,986	255,300	956,067	1,211,367	1,219,148	270,382	28.73%
6	Rate IS- Interruptible Service	222,000	1	984	19,252	20,236	1,200	24,962	26,162	26,218	5,926	29.28%
7	Rate SI- Small Industrial	59,459	4	3,936	11,113	15,049	4,800	14,432	19,232	19,497	4,184	27.80%
8		2,848,082	856	229,073	747,197	976,270	261,300	995,461	1,256,761	1,264,863	280,491	28.73%
9												
10	Transportation Customers											
11	Transport. Firm	1,881,944	11	10,824	351,735	362,559	13,200	456,804	470,004	469,734	107,445	29.64%
12	Transport. Firm- Fixed	8,470,343	1	536,493		536,493	536,493		536,493	536,493	0	0.00%
13	Transport. Firm- Volumetric	7,175,742	1		445,540	445,540		445,540	445,540	445,540		0.00%
14	Transport. Firm- DDQ	947,972	56	14,750	264,759	279,509	16,800	353,119	369,919	362,134	90,410	32.35%
15	Rate I - Large Industrial	3,581,019	1	0	360,079	360,079	3,600	462,913	466,513	466,521	106,434	29.56%
16	Transport. Interruptible	4,139,559	4	3,936	358,983	362,919	4,800	465,452	470,252	470,200	107,333	29.58%
17		26,196,578	74	566,003	1,781,096	2,347,099	574,893	2,183,828	2,758,721	2,750,622	411,622	17.54%
18												
19	TOTAL	34,930,969	7,516	$1,771,097	$4,711,819	$6,482,916	$1,942,613	$6,166,415	$8,109,028	$8,109,016	$1,626,112	25.08%
20												
21	Overall Distribution Increase										25.08%	

B4-1

Valley Energy, Inc. (PA)
Rate Case with Fully Projected Future Test Year 2026

Billing Units, Rates And Revenue At PRESENT Rates
Fully Projected Future Test Year December 31, 2026

Line	Description	Rate R- Residential	Rate C- Commercial	Rate IS- Interruptible Service	Rate SI- Small Industrial	Rate ST- Transport Firm	Rate I Large Industrial Firm	Transport Firm- Contract	Transport. Firm- DDQ	Transport. Interruptible	Total
1					**BILLING UNITS**						
2	ccf Sales	5,886,309	2,566,623	222,000	59,459	1,881,944	3,581,019	15,646,085	947,972	4,139,559	34,930,969
3											
4	Number of Bills	79,030	10,212	12	48	132	12	24	672	48	90,190
5	Average Monthly Bills	6,586	851	1	4	11	1	2	56	4	7,516
6											
7					**RATES AND CHARGES**						
8					**Tariff Rates**						
9	Customer Charge	$12.35	$21.95	$82.00	$82.00	$82.00		$0.00	$21.95	$82.00	
10								Contract-2			
11	Commodity Block 1	$0.370950	$0.279290	$0.086720	$0.186900	$0.186900	$0.141580	$0.0526	$0.279290	$0.086720	
12	Commodity Block 2						$0.086960	$0.0526			
13	Commodity Block 3						$0.056970				
14											
15	Demand Block 1						$1.554320				
16	Demand Block 2						$0.806600	Contract-1			
17	Fixed Monthly, Oct-Dec							$44,375	10/2025-09/2026		
18	Fixed Monthly, Jan-Sep							$45,706	10/2026-		
19					**COMPUTATION OF REVENUE**						
20	Fixed Charge Revenue	976,021	224,153	984	3,936	10,824		536,493	14,750	3,936	1,771,097
21	Volumetric Revenue	2,183,526	716,832	19,252	11,113	351,735	360,079	445,540	264,759	358,983	4,711,819
22	**Total Distribution Revenue**	$3,159,547	$940,986	$20,236	$15,049	$362,559	$360,079	$982,033	$279,509	$362,919	$6,482,916
23											
24					**BILLING UNITS- DETAIL**						
25	ccf Sales	5,886,309	2,566,623	222,000	59,459	1,881,944	3,581,019	15,646,085	947,972	4,139,559	34,930,969
26	Customers	6,586	851	1	4	11	1	2	56	4	7,516
27											

Valley Energy, Inc. (PA)
Rate Case with Fully Projected Future Test Year 2026

Billing Units, Rates And Revenue At PROPOSED Rates
Fully Projected Future Test Year December 31, 2026

Line	Description	Rate R- Residential	Rate C- Commercial	Rate IS- Interruptible Service	Rate SI- Small Industrial	Rate ST- Transport Firm	Rate I Large Industrial Firm	Transport Firm- Contract	Transport. Firm- DDQ	Transport. Interruptible	Total
1		**BILLING UNITS**									
2	ccf Sales	5,886,309	2,566,623	222,000	59,459	1,881,944	3,581,019	15,646,085	947,972	4,139,559	34,930,969
3											
4	Number of Bills	79,030	10,212	12	48	132	12	24	672	48	90,190
5	Average Monthly Bills	6,586	851	1	4	11	1	2	56	4	7,516
6											
7		**RATES AND CHARGES**									
8		**Tariff Rates**									
9	Customer Charge	$14.00	$25.00	$100.00	$100.00	$100.00	$300.00	$0.00	$25.00	$100.00	
10								Contract-2			
11	Commodity Block 1	$0.50747	$0.37250	$0.11244	$0.24273	$0.24273	$0.18343	$0.0526	$0.37250	$0.11244	
12	Commodity Block 2						$0.09734	$0.0526			
13	Commodity Block 3										
14											
15	Demand Block 1						$2.01379				
16	Demand Block 2						$1.04504	Contract-1			
17	Fixed Monthly, Oct-Dec							44,375	Thru Sep		
18	Fixed Monthly, Jan-Sep							45,706	Oct-Dec		
19		**COMPUTATION OF REVENUE**									
20	Fixed Charge Revenue	1,106,420	255,300	1,200	4,800	13,200	3,600	536,493	16,800	4,800	1,942,613
21	Volumetric Revenue	2,987,125	956,067	24,962	14,432	456,804	462,913	445,540	353,119	465,452	6,166,415
22	**Total Distribution Revenue**	$4,093,545	$1,211,367	$26,162	$19,232	$470,004	$466,513	$982,033	$369,919	$470,252	**$8,109,028**
23	Target	4,093,531	1,219,148	26,218	19,497	469,734	466,521	982,033	362,134	470,200	8,109,016
24		**BILLING UNITS- DETAIL**									
25	Block 1 ccf Sales	5,886,309	2,566,623	222,000	59,459	1,881,944	3,581,019	15,646,085	947,972	4,139,559	34,930,969
26										*Check*	*34,930,969*
27	Proposed Customer charges	$14.00	$25.00	$100.00	$100.00	$100.00	$300.00		$25.00	$100.00	
28	Increase in Customer charges	13.36%	13.90%	21.95%	21.95%	21.95%			13.90%	21.95%	

Valley Energy, Inc. (PA)
Rate Case with Fully Projected Future Test Year 2026

Summary Of Present And Proposed Tariff Rates
Historic Year December 31, 2024 and Fully Projected Future Test Year December 31, 2026

Line		Present Rates (excluding GCR)	GCR Current	Present Rates (including GCR prsesent rate)	Proposed Rates (excluding GCR)	GCR Current	Proposed Rates (including GCR present rate)	Proposed Increase (excluding GCR)	Proposed Increase (including GCR present rate)
1	**Rate R- Residential**								
2	Customer Charge per Bill	$12.35		$12.35	$14.00		$14.00	13.36%	13.36%
3									
4	Commodity charge per ccf								
5	All usage	$0.37095	$0.34569	$0.71664	$0.50747	$0.34569	$0.85316	36.80%	19.05%
6	**Rate C- Commercial**								
7	Customer Charge per Bill	$21.95		$21.95	$25.00		$25.00	13.90%	13.90%
8									
9	Commodity charge per ccf								
10	All usage	$0.27929	$0.34569	$0.62498	$0.37250	$0.34569	$0.71819	33.37%	14.91%
11	**Rate I- Large Industrial Firm**								
12	Customer Charge per Bill			$0.00	$300.00		$300.00		
13									
14	Commodity charge per ccf								
15	Block 1	$0.14158	$0.34569	$0.48727	$0.18343	$0.34569	$0.52912	29.56%	8.59%
16	Block 2	$0.08696	$0.34569	$0.43265	$0.09734	$0.34569	$0.44303	11.94%	2.40%
17	Block 3	$0.05697	$0.34569	$0.40266					
18									
19	Demand charge per mcf								
20	Block 1	$1.554320		$1.55432	$2.01379		$2.01379	29.56%	29.56%
21	Block 2	$0.806600		$0.80660	$1.04504		$1.04504	29.56%	29.56%
22	**Rate IS- Interruptible Service**								
23	Customer Charge per Bill	$82.00		$82.00	$100.00		$100.00	21.95%	21.95%
24									
25	Transport charge per ccf								
26	All usage	$0.08672		$0.0867	$0.11244		$0.1124	29.66%	29.66%

Valley Energy, Inc. (PA)
Rate Case with Fully Projected Future Test Year 2026

Summary Of Present And Proposed Tariff Rates
Historic Year December 31, 2024 and Fully Projected Future Test Year December 31, 2026

Line		Present Rates (excluding GCR)	GCR Current	Present Rates (including GCR prsesent rate)	Proposed Rates (excluding GCR)	GCR Current	Proposed Rates (including GCR present rate)	Proposed Increase (excluding GCR)	Proposed Increase (including GCR present rate)
27	**Rate SI- Small Industrial**								
28	Customer Charge per Bill	$82.00		$82.00	$100.00		$100.00	21.95%	21.95%
29									
30	Demand charge per mcf								
31	All usage	$0.1869	$0.3457	$0.5326	$0.2427	$0.3457	$0.5884	29.87%	10.48%
32	**Rate ST- Transport Firm**								
33	Customer Charge per Bill	$82.00		$82.00	$100.00		$100.00	21.95%	
34									
35	Transport charge per ccf								
36	All usage	$0.1869		$0.1869	$0.2427		$0.2427	29.87%	29.87%
37	**Transport. Firm- DDQ**								
38	Customer Charge per Bill	$21.95		$21.95	$25.00		$25.00	13.90%	13.90%
39									
40	Transport charge per ccf								
41	All usage	$0.2793		$0.2793	$0.3725		$0.3725	33.37%	33.37%
42	**Transport. Interruptible**								
43	Customer Charge per Bill	$82.00		$82.00	$100.00		$100.00	21.95%	
44									
45	Transport charge per ccf								
46	All usage	$0.0867		$0.0867	$0.1124		$0.1124	29.66%	29.66%

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Valley Energy, Inc. (PA)
Rate Case with Fully Projected Future Test Year 2026

Bill Comparisons (including GCR present rate)
Fully Projected Future Test Year December 31, 2026
Rate R- Residential

Line	Average	Sales (ccf)	Present Rates		Proposed Rates		Increase	
			Monthly Bill	Cost per ccf	Monthly Bill	Cost per ccf	$ per Monthly	%
1		Minimum	$12.35		$14.00		$1.65	13.36%
2		10	19.52	$1.95164	22.53	$2.25316	3.02	15.45%
3		20	26.68	1.33414	31.06	1.55316	4.38	16.42%
4	All Residential, Apr-Sep	36	38.15	1.05970	44.71	1.24205	6.56	17.21%
5		50	48.18	0.96364	56.66	1.13316	8.48	17.59%
6	All Residential, Annual	76	66.81	0.87914	78.84	1.03737	12.03	18.00%
7	All Residential, Oct-Mar	117	96.20	0.82220	113.82	0.97282	17.62	18.32%
8		150	119.85	0.79897	141.97	0.94649	22.13	18.46%
9		200	155.68	0.77839	184.63	0.92316	28.95	18.60%
10		250	191.51	0.76604	227.29	0.90916	35.78	18.68%
11								

Rate C- Commercial

13								
14			Present Rates		Proposed Rates		Increase	
15	Average	Sales (ccf)	Monthly Bill	Cost per ccf	Monthly Bill	Cost per ccf	$ per Monthly	%
16		Minimum	$21.95		$25.00		$3.05	13.90%
17		25	37.57	$1.50298	42.95	$1.71819	5.38	14.32%
18		50	53.20	1.06398	60.91	1.21819	7.71	14.49%
19		100	84.45	0.84448	96.82	0.96819	12.37	14.65%
20		200	146.95	0.73473	168.64	0.84319	21.69	14.76%
21	All Commercial, Annual	258	183.19	0.71006	210.29	0.81509	27.10	14.79%
22		300	209.44	0.69815	240.46	0.80152	31.01	14.81%
23		400	271.94	0.67986	312.28	0.78069	40.33	14.83%
24		500	334.44	0.66888	384.10	0.76819	49.65	14.85%
25		750	490.69	0.65425	563.64	0.75152	72.96	14.87%
26		1,000	646.93	0.64693	743.19	0.74319	96.26	14.88%
27								

B5-1

Valley Energy, Inc. (PA)
Rate Case with Fully Projected Future Test Year 2026

Bill Comparisons (including GCR present rate)
Fully Projected Future Test Year December 31, 2026
Rate SI- Small Industrial

			Present Rates		Proposed Rates		Increase	
Average	**Sales (ccf)**	**Monthly Bill**	**Cost per ccf**	**Monthly Bill**	**Cost per ccf**	**$ per Monthly**	**%**
	Minimum	$82.00		$100.00		$18.00	21.95%
	2,000	1,147.18	$0.57359	1,276.84	$0.63842	129.66	11.30%
	4,000	2,212.36	0.55309	2,453.68	0.61342	241.32	10.91%
	6,000	3,277.54	0.54626	3,630.52	0.60509	352.98	10.77%
	8,000	4,342.72	0.54284	4,807.36	0.60092	464.64	10.70%
	10,000	5,407.90	0.54079	5,984.20	0.59842	576.30	10.66%
	12,000	6,473.08	0.53942	7,161.04	0.59675	687.96	10.63%
	14,000	7,538.26	0.53845	8,337.88	0.59556	799.62	10.61%
	16,000	8,603.44	0.53772	9,514.72	0.59467	911.28	10.59%
	18,000	9,668.62	0.53715	10,691.56	0.59398	1,022.94	10.58%
	20,000	10,733.80	0.53669	11,868.40	0.59342	1,134.60	10.57%

B5-2

Valley Energy, Inc. (PA)
Rate Case with Fully Projected Future Test Year 2026

Bill Comparisons (excluding GCR)
Fully Projected Future Test Year December 31, 2026
Rate R- Residential

Line	Average	Sales (ccf)	Present Rates		Proposed Rates		Increase	
			Monthly Bill	Cost per ccf	Monthly Bill	Cost per ccf	$ per Monthly	%
1		Minimum	$12.35		$14.00		$1.65	13.36%
2		10	16.06	$1.60595	19.07	$1.90747	3.02	18.78%
3		20	19.77	0.98845	24.15	1.20747	4.38	22.16%
4	All Residential, Apr-Sep	36	25.70	0.71401	32.27	0.89636	6.56	25.54%
5		50	30.90	0.61795	39.37	0.78747	8.48	27.43%
6	All Residential, Annual	76	40.54	0.53345	52.57	0.69168	12.03	29.66%
7	All Residential, Oct-Mar	117	55.75	0.47651	73.37	0.62713	17.62	31.61%
8		150	67.99	0.45328	90.12	0.60080	22.13	32.54%
9		200	86.54	0.43270	115.49	0.57747	28.95	33.46%
10		250	105.09	0.42035	140.87	0.56347	35.78	34.05%
11								

Rate C- Commercial

12								
13								
14			Present Rates		Proposed Rates		Increase	
15	Average	Sales (ccf)	Monthly Bill	Cost per ccf	Monthly Bill	Cost per ccf	$ per Monthly	%
16		Minimum	$21.95		$25.00		$3.05	13.90%
17		25	28.93	$1.15729	34.31	$1.37250	5.38	18.60%
18		50	35.91	0.71829	43.63	0.87250	7.71	21.47%
19		100	49.88	0.49879	62.25	0.62250	12.37	24.80%
20		200	77.81	0.38904	99.50	0.49750	21.69	27.88%
21	All Commercial, Annual	258	94.01	0.36437	121.11	0.46940	27.10	28.83%
22		300	105.74	0.35246	136.75	0.45583	31.01	29.33%
23		400	133.67	0.33417	174.00	0.43500	40.33	30.18%
24		500	161.60	0.32319	211.25	0.42250	49.66	30.73%
25		750	231.42	0.30856	304.38	0.40583	72.96	31.53%
26		1,000	301.24	0.30124	397.50	0.39750	96.26	31.95%
27								

B5-2

Valley Energy, Inc. (PA)
Rate Case with Fully Projected Future Test Year 2026

Bill Comparisons (excluding GCR)
Fully Projected Future Test Year December 31, 2026
Rate SI- Small Industrial

			Present Rates		Proposed Rates		Increase	
Average	Sales (ccf)	Monthly Bill	Cost per ccf	Monthly Bill	Cost per ccf	$ per Monthly	%
	Minimum	$82.00		$100.00		$18.00	21.95%
	2,000	455.80	$0.22790	585.46	$0.29273	129.66	28.45%
	4,000	829.60	0.20740	1,070.92	0.26773	241.32	29.09%
	6,000	1,203.40	0.20057	1,556.38	0.25940	352.98	29.33%
	8,000	1,577.20	0.19715	2,041.84	0.25523	464.64	29.46%
	10,000	1,951.00	0.19510	2,527.30	0.25273	576.30	29.54%
	12,000	2,324.80	0.19373	3,012.76	0.25106	687.96	29.59%
	14,000	2,698.60	0.19276	3,498.22	0.24987	799.62	29.63%
	16,000	3,072.40	0.19203	3,983.68	0.24898	911.28	29.66%
	18,000	3,446.20	0.19146	4,469.14	0.24829	1,022.94	29.68%
	20,000	3,820.00	0.19100	4,954.60	0.24773	1,134.60	29.70%

Valley Energy, Inc. (PA)
Rate Case with Fully Projected Future Test Year 2026
Net Operating Income And Rates of Return
Years Ended 12/31/2024, 12/31/2025 and 12/31/2026
Answer to 52 Pa. Code 53.52 c[1]

Line	Description	Historic Year December 31, 2024		Future Test Year December 31, 2025	Present Rates Fully Projected Future Test Year December 31, 2026	Revenue Requirement Fully Projected Future Test Year December 31, 2026	Proposed Rates Fully Projected Future Test Year December 31, 2026
		Per Books	Distribution Only	Distribution Only	Distribution Only	Distribution Only	Distribution Only
1	REVENUE						
2	Residential	$4,526,671	$2,823,518	$3,135,633	$3,159,547		4,093,545
3	Commercial and industrial	1,764,263	893,396	976,270	976,270		1,256,761
4	Transportation	2,217,436	2,217,436	2,321,925	2,347,099		2,758,721
5	Operating revenue	8,508,370	5,934,349	6,433,828	6,482,916	8,109,016	8,109,028
6	Other revenue, net	21,204	21,204	23,575	23,575	23,575	23,575
7	Total Revenue	8,529,574	5,955,553	6,457,402	6,506,491	8,132,590	8,132,602
8	*ccf*	*32,948,558*		*34,886,478*	*34,930,969*	*34,930,969*	*34,930,969*
9	EXPENSES				Increase	1,626,099	
10	Purchased gas (in revenue)	3,650,808					
11	Distribution	1,885,489	1,885,489	1,725,247	1,939,388	1,939,388	1,939,388
12	Customer accounting & collection	649,422	649,422	742,899	769,686	784,578	784,578
13	Rate case expense normalization				92,222	92,222	92,222
14	Administrative & general expenses	1,119,082	1,119,082	1,194,040	1,278,704	1,278,704	1,278,704
15	Total Operating expenses	7,304,802	3,653,994	3,662,186	4,080,000	4,094,892	4,094,892
16							
17	Depreciation expense	1,307,234	1,307,234	1,425,492	1,542,548	1,542,548	1,542,548
18	Taxes other than income	29,354	29,354	31,385	33,587	33,587	33,587
19							
20	Total Expenses	8,641,390	4,990,582	5,119,063	5,656,136	5,671,028	5,671,028
21							
22	Oper Inc (Loss) before Income Tax	(111,816)	964,972	1,338,339	850,355	2,461,562	2,461,574
23							
24	Income tax expense	(353,801)	28,530	91,834	(86,953)	378,559	378,562
25	NET UTILITY OPERATING INCOME (LOSS) (A)	$241,986	$936,442	$1,246,505	$937,308	$2,083,003	$2,083,012
26							
27	RATE BASE (B)	$21,798,301	$21,798,301	$23,553,480	$25,187,466	$25,187,466	$25,187,466
28	RATE OF RETURN ON RATE BASE (	1.11%	4.30%	5.29%	3.72%	8.27%	8.27%
29							

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Valley Energy, Inc. (PA)
Rate Case with Fully Projected Future Test Year 2026
Net Operating Income And Rates of Return
Years Ended 12/31/2024, 12/31/2025 and 12/31/2026
Answer to 52 Pa. Code 53.52 c[1] - Support Sheet No. 1
Support Sheet No. 1- Operating Expense and Going-Level Adjustments

Line	Acct	Account Description	Historic Year December 31, 2024	Adjust HTY to FTY	Future Test Year December 31, 2025	Adjust FTY to FPFTY	Fully Projected Future Test Year December 31, 2026	LABOR Historic Year December 31, 2024	LABOR Future Test Year December 31, 2025	LABOR Fully Projected Future Test Year December 31, 2026
1		Distribution Expenses								
2	842	Fuel	21,175	(45)	21,130	(783)	20,347	0	0	0
3	870	Labor Supv /Eng.	212,953	26,077	239,030	21,517	260,547	91,173	103,788	113,359
4	871	Distrib Load Disp	6,180	583	6,763	338	7,101	0	0	0
5	874	Mains & Services	454,825	(4,337)	450,488	129,994	580,482	167,959	136,278	193,236
6	875	Meas & Reg- Gen	102,219	(3,931)	98,288	8,432	106,720	39,962	35,758	40,056
7	876	Ind / Com Meters, Reg	102,463	(19,945)	82,517	11,884	94,402	8,437	31,539	36,372
8	877	Meas & Reg- City gate	34,460	(4,213)	30,247	1,882	32,129	67,681	6,288	7,065
9	878	Meters & House Reg	165,846	(21,594)	144,252	15,370	159,622	82,768	60,218	67,498
10	879	Cust installations	197,343	(24,159)	173,184	16,860	190,044	41,265	72,453	80,239
11	880	Other operating exp	114,706	(60,271)	54,435	16,249	70,684	0	20,603	27,982
12	881	Rents	5,803	419	6,222	447	6,669	0	0	0
13		*Total Operation*	1,417,971	(111,416)	1,306,556	222,190	1,528,746	499,245	466,925	565,807
14										
15	885	Super and eng	35,008	2,730	37,738	1,884	39,622	14,259	15,514	16,318
16	886	Structures & improve	38,923	(12,458)	26,465	(6,247)	20,218	7,393	7,488	6,038
17	887	Mains	107,656	10,252	117,909	15,556	133,465	31,237	36,769	43,282
18	889	Meas & Reg- Gen	76,337	(10,683)	65,654	(13,051)	52,603	34,739	20,343	18,035
19	890	Meas & Reg- Ind	23,623	(60)	23,563	2,726	26,289	0	8,837	10,141
20	891	Meas & Reg- City gate	6,926	963	7,889	4,902	12,791	1,736	1,715	1,979
21	892	Services	54,019	4,578	58,597	12,684	71,281	19,182	20,480	26,012
22	893	Meters & House Reg	125,026	(44,149)	80,876	(26,505)	54,372	44,570	29,166	23,748
23		*Total Maintenance*	467,518	(48,827)	418,691	(8,050)	410,641	153,117	140,312	145,553
24		*Total Distribution*	1,885,489	(160,242)	1,725,247	214,141	1,939,388	652,362	607,237	711,360

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Valley Energy, Inc. (PA)
Rate Case with Fully Projected Future Test Year 2026
Net Operating Income And Rates of Return
Years Ended 12/31/2024, 12/31/2025 and 12/31/2026
Answer to 52 Pa. Code 53.52 c[1] - Support Sheet No. 1
Support Sheet No. 1- Operating Expense and Going-Level Adjustments

Line	Acct	Account Description	Historic Year December 31, 2024	Adjust HTY to FTY	Future Test Year December 31, 2025	Adjust FTY to FPFTY	Fully Projected Future Test Year December 31, 2026	LABOR Historic Year December 31, 2024	LABOR Future Test Year December 31, 2025	LABOR Fully Projected Future Test Year December 31, 2026
25										
26		Customer Accounting & Collection Expenses:								
27	902	Meter Reading Exp	25,595	2,510	28,106	(11,118)	16,988	8,187	9,734	6,193
28	903	Cust Rec & Coll Exp	610,473	17,502	627,975	33,628	661,603	194,876	214,654	229,723
29	904	Uncollect Acct (Dist)	(20,260)	70,755	50,495	3,853	54,348	0	0	0
30	905	Miscellaneous cust	19,214	2,278	21,492	0	21,492	0	0	0
31	909	Info & Inst Advert	12,402	372	12,774	383	13,157	0	0	0
32	913	Advertising	1,998	59	2,057	41	2,098	0	0	0
33		*Total Cust Acct & Coll*	649,422	93,477	742,899	26,787	769,686	203,063	224,388	235,916
34										
35		Administrative & General Expenses:								
36	920	A&G Salaries	655,639	(20,739)	634,899	48,775	683,674	276,347	276,347	298,043
37	921	Office Supp & Exp	56,476	22,894	79,370	2,020	81,390	0	0	0
38	923	Outside Services	84,557	(3,897)	80,660	4,835	85,495	0	0	0
39	924	Property Insurance	23,202	13,055	36,257	5,442	41,699	0	0	0
40	925	Injuries and damage	93,900	14,757	108,657	16,224	124,881	0	0	0
41	926	Empl Pens & Bene	6,502	3,396	9,898	296	10,194	0	0	0
42	928	Reg Comm Exp	89,218	10,296	99,514	6,000	105,514	0	0	0
43	930	General advertising	72,246	31,734	103,980	2,638	106,618	0	0	0
44	930CV	COVID-related	0	0	0	0	0	0	0	0
45	932	Maint Gen plant	37,342	3,463	40,805	(1,565)	39,240	8,168	8,168	8,203
46		*Total A&G*	1,119,082	74,958	1,194,040	84,664	1,278,704	284,515	284,515	306,246
47										
48		**Total Oper & Maint**	**3,653,994**	**8,192**	**3,662,186**	**325,592**	**3,987,778**	**1,139,940**	**1,116,140**	**1,253,522**
49										
50		Labor	1,140,934	(24,794)	1,116,140	137,382	1,253,522			
51		Transportation	122,958	311	123,269	3,698	126,967			
52		Material	315,608	(37,959)	277,649	12,228	289,877			
53		OH	1,451,655	(88,097)	1,363,558	128,036	1,491,594			
54		Other	622,839	158,731	781,570	44,248	825,818			
55			3,653,994	8,192	3,662,186	325,592	3,987,778			

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Valley Energy, Inc. (PA)
Rate Case with Fully Projected Future Test Year 2026

Support Sheet No. 2- Summary of Cost of Capital and Fair Rate of Return Based upon a Hypothetical Ratemaking Capital Structure
12/31/2026

Line	Type of Capital	Ratios (1)	Cost Rate	Weighted Cost Rate
1	Long-Term Debt	51.06%	5.03%	2.57%
2	Common Equity	48.94%	11.65%	5.70%
3	Total	100.00%		8.27%
4	TargetROR			8.27%
5				
6	[1] Recommended hypothetical capital structure ratios as discussed in direct testimony.			

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Valley Energy, Inc. (PA)
Rate Case with Fully Projected Future Test Year 2026
Net Operating Income And Rates of Return
Years Ended 12/31/2024, 12/31/2025 and 12/31/2026
Answer to 52 Pa. Code 53.52 c[1]
Support Sheet No. 3- Taxes Other Than Income

Line	Description	Historic Year December 31, 2024		Future Test Year December 31, 2025	PRESENT RATES Fully Projected Future Test Year December 31, 2026	PROPOSED RATES Fully Projected Future Test Year December 31, 2026
		Per Books	Distribution Only	Distribution Onl	Distribution Only	Distribution Only
1	Taxes other than income:					
2	Pennsylvania Use Tax	478	478	478	478	478
3	Public Utility Realty Tax	28,876	28,876	30,907	33,109	33,109
4						
5		$29,354	$29,354	$31,385	$33,587	$33,587
6						
7	Plant assets		43,575,245	46,639,469	49,963,792	49,963,792
8	Tax rate		0.06627%			
9						
10	**Rate case expense amortization**					
11	McNees (fully litigated)				180,000	
12	HSG Group (fully litigated(				48,000	
13	ScottMadden (fully litigated)				36,667	
14	BKD				2,000	
15	Printing, other				10,000	
16	Estimated expenses				$276,667	
17	Amortization period (years)				3	
18	Annual amortization expense				$92,222	
19						

Valley Energy, Inc. (PA)
Rate Case with Fully Projected Future Test Year 2026
Net Operating Income And Rates of Return
Years Ended 12/31/2024, 12/31/2025 and 12/31/2026
Answer to 52 Pa. Code 53.52 c[1]
Support Sheet No. 4- Income Tax Calculations

Line	Ddescription		Historic Year December 31, 2024		Future Test Year December 31, 2025	PRESENT RATES Fully Projected Future Test Year December 31, 2026	FULL REVENUE REQUIREMENT Fully Projected Future Test Year December 31, 2026	PROPOSED RATES Fully Projected Future Test Year December 31, 2026
			Per Books	Distribution Only	Distribution Only	Distribution Only	Distribution Only	Distribution Only
1	Net Operating Income Excluding Income Taxes		($111,816)	$964,972	$1,338,339	$850,355	$2,553,785	$2,553,797
2								
3	Non-Operating Expenses:							
4	Synchronized interest expense:							
5	Rate base		21,798,301	21,798,301	23,553,480	25,187,466	25,187,466	25,187,466
6								
7	Rate base for interest compuation		21,798,301	21,798,301	23,553,480	25,187,466	25,187,466	25,187,466
8	Weighted Cost of debt		2.570%	2.570%	2.570%	2.570%	2.570%	2.570%
9	Synchronized interest expense		560,216	560,216	605,324	647,318	647,318	647,318
10	Taxable income before depreciation tax adjustments		(672,032)	404,755	733,015	203,037	1,906,467	1,906,479
11								
12	Pennsylvania depreciation adjustment:							
13	Tax depreciation (using DDB method)		(2,115,013)	(2,115,013)	(2,528,871)	(2,227,569)	(2,227,569)	(2,227,569)
14	Book depreciation		1,307,234	1,307,234	1,425,492	1,542,548	1,542,548	1,542,548
15	Pennsylvania depreciation adjustment		(807,779)	(807,779)	(1,103,379)	(685,021)	(685,021)	(685,021)
16	Pennsylvania taxable income		(1,479,811)	499,455	322,114	(481,983)	1,221,446	1,221,458
17	Regulatory Pennsylvania income tax expense	9.99%	(147,833)	49,896	32,179	(48,150)	122,022	122,024
18								
19	Federal depreciation adjustment:		9.99%	9.99%	9.99%	9.99%	9.99%	9.99%
20	Tax depreciation (using SL method)		(1,763,836)	(1,763,836)	(1,842,256)	(1,978,510)	(1,978,510)	(1,978,510)
21	Book depreciation		1,307,234	1,307,234	1,425,492	1,542,548	1,542,548	1,542,548
22	Federal depreciation adjustment		(456,603)	(456,603)	(416,763)	(435,961)	(435,961)	(435,961)
23								
24	Taxable income before depreciation tax adjustments		(672,032)	404,755	733,015	203,037	1,906,467	1,906,479
25	Federal depreciation adjustment		(456,603)	(456,603)	(416,763)	(435,961)	(435,961)	(435,961)
26	Pennsylvania income tax expense		147,833	(49,896)	(32,179)	48,150	(122,022)	(122,024)
27	Federal taxable income		(980,801)	(101,743)	284,072	(184,774)	1,348,483	1,348,494
28	Regulatory Federal income tax expense	21.00%	(205,968)	(21,366)	59,655	(38,803)	283,181	283,184
29	Regulatory Total income tax expense		($353,801)	$28,530	$91,834	($86,953)	$405,204	$405,207
30								
31	Deferred Federal Income Tax expense (included in above):							
32	Tax depreciation (using SL method)		1,763,836	1,763,836	1,842,256	1,978,510	1,978,510	1,978,510
33	Tax depreciation (using DDB method)		2,115,013	2,115,013	2,528,871	2,227,569	2,227,569	2,227,569
34			351,176	351,176	686,615	249,059	249,059	249,059
35	Federal tax rate		21.00%	21.00%	21.00%	21.00%	21.00%	21.00%
36	Deferred Federal income tax (credit)		$73,747	$73,747	$144,189	$52,302	$52,302	$52,302
37	Combined statutory tax rate	28.89%	28.89%	28.89%	28.89%	28.89%	28.89%	28.89%

Valley Energy, Inc. (PA)
Rate Case with Fully Projected Future Test Year 2026
Net Operating Income And Rates of Return
Years Ended 12/31/2024, 12/31/2025 and 12/31/2026
Answer to 52 Pa. Code 53.52 c[1]
Support Sheet No. 5- Computation of Rate Base

Line	Description	Source	Historic Year December 31, 2024	Future Test Year December 31, 2025	Fully Projected Future Test Year December 31, 2026
1	Utility Plant in Service				
2	Assets	Schedule C3	$ 43,575,245	$ 46,639,469	$ 49,963,792
3	Less: Accumulated Depreciation	Schedule C3	(20,753,495)	(22,356,239)	(24,061,709)
4			22,821,750	24,283,230	25,902,083
5					
6	Less: Accumulated deferred income taxes	Line 31	(484,177)	(459,323)	(438,298)
7	Less: Customer deposits	Schedule C2	(394,763)	(394,763)	(394,763)
8	Natural gas inventories- avg balance for year	Workpaper 5 to Sch C	1,198,570	1,198,570	1,198,570
9	Unbundled, to be Recovered in GCR	To Schedule C4	(1,198,570)	(1,198,570)	(1,198,570)
10	Accrued OPEB Liability / OPEB Asset, net	Line 38	(848,035)	(571,368)	(617,479)
11	Materials & Supplies	Schedule C2	244,244	244,244	244,244
12			21,339,019	23,102,019	24,695,787
13	Cash Working Capital Allowance	Line 24	459,282	451,461	491,679
14	RATE BASE		$ 21,798,301	$ 23,553,480	$ 25,187,466
15					

Valley Energy, Inc. (PA)
Rate Case with Fully Projected Future Test Year 2026
Net Operating Income And Rates of Return
Years Ended 12/31/2024, 12/31/2025 and 12/31/2026
Answer to 52 Pa. Code 53.52 c[1]
Support Sheet No. 5- Computation of Rate Base

Line	Description	Source	Historic Year December 31, 2024	Future Test Year December 31, 2025	Fully Projected Future Test Year December 31, 2026
16	Cash Working Capital Allowance:				
17	Operating Expenses	Schedule C1	$ 8,641,390	$ 5,119,063	$ 5,656,136
18	Deductions:				
19	Purchased Gas	Schedule C1	3,650,808	0	0
20	Depreciation Expense, Uncollectible, TOTI	Schedule C1	1,316,328	1,507,372	1,722,706
21	Total Deductions		4,967,136	1,507,372	1,722,706
22	Cash Operating Expenses		3,674,254	3,611,691	3,933,430
23	Cash Operating Expenses Ratio		1/8	1/8	1/8
24	Cash Working Capital Allowance		$ 459,282	$ 451,461	$ 491,679
25					
26	Regulatory Accumluated deferred income tax:				
27	Accumulated depreciation based on tax expense borne by ratepayers		37,481,985	39,313,415	41,266,769
28	Accumulated depreciation based on taxes paid by company		39,787,591	41,500,668	43,353,900
29	(Excess) depreciation taken by company		(2,305,606)	(2,187,253)	(2,087,132)
30	Federal tax rate		21.00%	21.00%	21.00%
31	Regulatory Accumluated deferred income tax (liability)		$ (484,177)	$ (459,323)	$ (438,298)
32					
33	Accrued OPEB Liability / OPEB Asset, net				
34	Accrued postretirement cost (Liability)		(816,705)	(816,705)	(816,705)
35	Regulatory (Liability)		(375,898)	(375,898)	(375,898)
36	Regulatory Assets			276,667	230,556
37	Deferred tax asset related to Regulatory Liabilities		344,568	344,568	344,568
38			(848,035)	(571,368)	(617,479)
39					

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Valley Energy, Inc. (PA)
Rate Case with Fully Projected Future Test Year 2026

Comparison to Prior Rate Case
Prior Rate Case and Fully Projected Future Test Year December 31, 2026

Line	Description	R-2022-3032300, Order	Fully Projected Future Test Year December 31, 2026	Difference-Needs Higher (Lower) Revenue
1	Revenue	6,478,861	6,506,491	(27,629)
2	*ccf*	*35,049,281*	*34,930,969*	
3				
4				
5	O&M	3,624,172	4,080,000	455,828
6	Taxes other than income, Rate Case	34,169	33,587	(581)
7	Depreciation	1,178,428	1,542,548	364,120
8	Income tax	254,071	405,204	151,132
9				
10	Rate Base	$19,756,771	$25,187,466	
11	Required Return	7.03%	8.27%	
12	Target Return	1,388,012	2,083,003	694,991
13				1,637,861
14	Uncollectibles		0.924%	15,139
15				
16	Rounding			(26,900)
17	Revenue Increase Required at Recommended Return			1,626,099
18	Per Schedule C1			1,626,099
19				

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Valley Energy, Inc. (PA)
Rate Case with Fully Projected Future Test Year 2026

Balance Sheets
Years Ended 12/31/2024, 12/31/2025 and 12/31/2026
Answer to 52 Pa. Code 53.52 c[2]

Line	Account Title	Per Books 12/31/2024	Pro Forma 12/31/2025	Pro Forma 12/31/2026
1	**Assets and Other Debits**			
2	Utility Plant			
12	Gas plant in service for ratemaking	$43,575,245	$46,639,469	$49,963,792
13				
14	Construction work in progress	174,722	174,722	174,722
15	Accumulated depreciation for ratemaking	(20,753,495)	(22,356,239)	(24,061,709)
16	*Total utility plant*	22,996,472	24,457,952	26,076,805
17	Non-Jurisdictional Plant, net	2,097,165	2,097,165	2,097,165
18	Other Property and Investments:			
19	RS Plan Prepayment		0	0
20	Regulatory asset	52,196	52,196	52,196
21	*Total other property and investments*	52,196	52,196	52,196
22				
23	Current Assets:			
24	Cash	802,679	802,679	802,679
25	Customer accounts receivable	624,279	624,279	624,279
26	Unbilled revenues	478,620		
27	Other receivables	255,292		
28	Advances to affiliates	1,340,221	1,340,221	1,340,221
29	Natural gas inventories	722,281	722,281	722,281
30	Materials and supplies	244,244	244,244	244,244
31	Prepayments	331,357	331,357	331,357
32	*Total current assets*	4,798,973	4,065,061	4,065,061
33				
34	**Total Assets and Other Debits**	**$29,944,806**	**$30,672,374**	**$32,291,227**
35				

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Valley Energy, Inc. (PA)
Rate Case with Fully Projected Future Test Year 2026

Balance Sheets
Years Ended 12/31/2024, 12/31/2025 and 12/31/2026
Answer to 52 Pa. Code 53.52 c[2]

Line	Account Title	Per Books 12/31/2024	Pro Forma 12/31/2025	Pro Forma 12/31/2026
36	**Liabilities and Other Credits**			
37	Proprietary Capital:			
38	Common stock Issued	$768,293	$768,293	$768,293
39	Retained earnings	14,404,719	15,651,224	16,588,532
40	*Total proprietary capital*	15,173,012	16,419,517	17,356,825
41				
42	Long-Term Debt:			
43	Long Term Debt incl Cap Leases	5,838,390	5,201,042	4,514,401
44	*Total long-term debt*	5,838,390	5,201,042	4,514,401
45				
46	Current and Accrued Liabilities:			
47	Cash (over) under	2,650,000	2,719,118	4,047,928
48	Current maturities of Long Term Debt	637,348	686,641	726,017
49	Accounts payable and accruals	924,199	924,199	924,199
50	Due for purchased gas	495,267	495,267	495,267
51	Customer deposits	394,763	394,763	394,763
52	Over collected gas costs	287,624	287,624	287,624
53	*Total current and accrued liabilities*	5,389,201	5,507,612	6,875,798
54				
55	Deferred Credits and Other Liabilities:			
56	Deferred taxes	2,351,600	2,351,600	2,351,600
57	Accrued postretirement cost	816,705	816,705	816,705
58	Regulatory liability	375,898	375,898	375,898
59	*Total deferred credits*	3,544,203	3,544,203	3,544,203
60				
61	**Total Liabilities and Other Credits**	**$29,944,806**	**$30,672,374**	**$32,291,227**

Valley Energy, Inc. (PA)
Rate Case with Fully Projected Future Test Year 2026
Original Cost of Utility Plant in Service
Years Ended 12/31/2024, 12/31/2025 and 12/31/2026
Answer to 52 Pa. Code 53.52 c[3]

					Original Cost			Original Cost		
				12/31/2024	Year 2025	Year 2025	12/31/2025	Year 2026	Year 2026	12/31/2026
Line	Acct No.	Account Title		Balance	Additions	Removals	Balance	Additions	Removals	Balance
1	*Distribution Plant.*									
2	114	Gas Plant Acquisition Adjustment		3,361,289			3,361,289			3,361,289
3	366	Trans. Structures and improvements	(A)	117,592	0		117,592	0		117,592
4	367	Trans. Mains	(A)	1,917,201	0		1,917,201	0		1,917,201
5	369	Trans. Meas / Reg Sta Equp	(A)	402,427	0		402,427	0		402,427
6	374	Land & Land Rights		15,652	0		15,652	0		15,652
7	375	Structures and improvements		204,060	1,218,878		1,422,938	457,937		1,880,875
8	376S	Mains- Steel		3,820,156	43,909		3,864,065	44,080		3,908,144
9	376P	Mains- Plastic		11,410,116	223,134	(434)	11,632,816	1,188,320	(404)	12,820,732
10	378	Meas / Reg Sta Equp		1,590,567	406,925		1,997,492	244,879		2,242,371
11	380S	Services- Steel		581,198	0	(9,027)	572,171	0	(10,385)	561,786
12	380P	Services- Plastic		9,843,941	767,950	(1,364)	10,610,526	1,055,387	(14,366)	11,651,547
13	381	Meters		1,945,136	47,842		1,992,978	61,305		2,054,284
14	381RC	Transponders- Res/Comm		1,010,228			1,010,228			1,010,228
15	381AMR	Meters-AMR		282,510	2,009		284,519	9,121		293,640
16	381Prot	Meters-Protection		61,435	10,611		72,046	0		72,046
17	383	House regulators		335,586	4,500		340,086	4,500		344,586
18	385	Indu Meas / Reg Sta Equp		1,260,536	26,400		1,286,936	13,200		1,300,136
19	387	Other equipment		9,978	0		9,978	0		9,978
20	Total Distribution Plant			38,169,608	2,752,157	(10,826)	40,910,940	3,078,729	(25,156)	43,964,513
21										
22	*General Plant*									
23	390	Structures & Improvements		4,055,042	0		4,055,042	0		4,055,042
24	391	Office Furniture & Equipment		1,230,002	6,200		1,236,202	0		1,236,202
25	391C	Computer equipment		147,442	147,442		294,884	125,750		420,634
26	392	Transportation Equipment		1,214,676	80,000		1,294,676	100,000		1,394,676
27	393	Stores Equipment		48,547	20,000		68,547	0		68,547
28	394	Tools, Shop & Garage Equipment		717,363	68,750		786,113	45,000		831,113
29	396	Power Operated		499,528	0		499,528	0		499,528
30	397	Communication Equipment		245,077	500		245,577	0		245,577
31	398	Miscellaneous Equipment		14,718			14,718			14,718
32	301	Intangible plant, organization		22,107			22,107			22,107
33	389	Land & Land Rights		572,424			572,424			572,424
34		Total General Plant		8,766,926	322,892	0	9,089,818	270,750	0	9,360,568
35										
36		Less: Acquisition		(3,361,289)	0	0	(3,361,289)	0	0	(3,361,289)
37		Total Plant in Service		$43,575,245	$3,075,049	($10,826)	$46,639,469	$3,349,479	($25,156)	$49,963,792
38		Less: Clearing, Charged to NY		$46,936,534			$50,000,758			$53,325,081
39				$46,936,534			$50,000,758			$53,325,081

Valley Energy, Inc. (PA)
Rate Case with Fully Projected Future Test Year 20
Original Cost of Utility Plant in Service
Years Ended 12/31/2024, 12/31/2025 and 12/31/202
Answer to 52 Pa. Code 53.52 c[3]

Line	Acct No.	Account Title	Depr. Rate	Year 2024 Depr Exp	Accumulated Depreciation 12/31/2024 Balance	Year 2025 Depr Exp	Year 2025 Removals	Accumulated Depreciation 12/31/2025 Balance	Year 2026 Depr Exp	Year 2026 Removals	Accumulated Depreciation 12/31/2026 Balance	Net Book Value 12/31/2026 Balance
1	*Distribution Plant.*											
2	114	Gas Plant Acquisition Adjustment	3.47%	88,183	2,847,221	116,637		2,963,858	116,637		3,080,494	280,795
3	366	Trans. Structures and improvements	0.62%	730	7,146	729		7,875	729		8,604	108,988
4	367	Trans. Mains	1.79%	34,311	1,225,993	34,318		1,260,311	34,318		1,294,629	622,572
5	369	Trans. Meas / Reg Sta Equp	4.40%	17,723	296,228	17,707		313,935	17,707		331,642	70,785
6	374	Land & Land Rights	4.40%		0	689		689	689		1,377	14,275
7	375	Structures and improvements	2.63%	5,363	105,540	21,395		126,935	43,445		170,380	1,710,495
8	376S	Mains- Steel	3.15%	120,867	2,769,349	121,026		2,890,375	122,412		3,012,788	895,357
9	376P	Mains- Plastic	2.02%	226,954	3,788,947	232,738	(434)	4,021,251	246,985	(404)	4,267,832	8,552,900
10	378	Meas / Reg Sta Equp	6.72%	100,343	1,221,758	120,559		1,342,317	142,459		1,484,776	757,594
11	380S	Services- Steel	3.04%	18,399	218,783	17,668	(9,027)	227,424	17,394	(10,385)	234,433	327,353
12	380P	Services- Plastic	3.41%	318,053	4,396,438	348,772	(1,364)	4,743,846	379,813	(14,366)	5,109,292	6,542,255
13	381	Meters	2.74%	62,737	1,135,963	53,952		1,189,915	55,447		1,245,363	808,921
14	381RC	Transponders- Res/Comm	2.74%	22,968	312,762	27,680		340,442	27,680		368,122	642,106
15	381AMR	Meters-AMR	2.74%	3,870	8,670	7,768		16,438	7,921		24,359	269,281
16	381Prot	Meters-Protection	2.74%	842	1,356	1,829		3,185	1,974		5,159	66,887
17	383	House regulators	3.22%	10,792	260,864	10,878		271,742	11,023		282,766	61,820
18	385	Indu Meas / Reg Sta Equp	4.11%	40,510	856,743	52,351		909,094	53,164		962,258	337,878
19	387	Other equipment	3.66%	364	7,651	365		8,016	365		8,381	1,597
20	Total Distribution Plant			1,073,009	19,461,412	1,187,061	(10,826)	20,637,648	1,280,163	(25,156)	21,892,656	22,071,857
21												
22	*General Plant*											
23	390	Structures & Improvements	2.43%	74,191	870,711	98,538		969,249	98,538		1,067,786	2,987,256
24	391	Office Furniture & Equipment	13.10%	267,559	1,115,240	161,536		1,276,776	161,942		1,438,719	(202,517)
25	391C	Computer equipment	6.75%	9,552	9,952	14,928		24,880	24,149		49,029	371,605
26	392	Transportation Equipment	12.00%	68,719	1,030,813	150,561		1,181,374	161,361		1,342,735	51,941
27	393	Stores Equipment	6.67%	2,804	25,535	3,905		29,440	4,572		34,012	34,535
28	394	Tools, Shop & Garage Equipment	5.00%	27,591	523,999	37,587		561,586	40,431		602,017	229,096
29	396	Power Operated	11.76%	48,647	382,238	58,744		440,982	58,744		499,727	(199)
30	397	Communication Equipment	6.67%	10,527	179,026	16,363		195,389	16,380		211,769	33,808
31	398	Miscellaneous Equipment	6.67%	895	1,790	982		2,772	982		3,753	10,965
32	301	Intangible plant, organization	0.00%			0		0	0		0	22,107
33	389	Land & Land Rights	0.00%			0		0	0		0	572,424
34		Total General Plant		510,485	4,139,304	543,145	0	4,682,449	567,099	0	5,249,548	4,111,020
35												
36		Less: Acquisition		(88,183)	(2,847,221)	(116,637)	0	(2,963,858)	(116,637)	0	(3,080,494)	(295,069)
37		Total Plant in Service		$1,495,311	$20,753,495	$1,613,569	($10,826)	$22,356,239	$1,730,625	($25,156)	$24,061,709	$25,887,808
38		Less: Clearing, Charged to NY		(188,077)	$23,600,716	(188,077)			(188,077)			
39				$1,307,234	$23,600,716	$1,425,492			$1,542,548			25,902,083

WP

Valley Energy, Inc. (PA)
Rate Case with Fully Projected Future Test Year 2026
INDEX TO WORKPAPERS

Line	SCHEDULE	DESCRIPTION	PERIOD
1	Index To Workpapers		
2	Workpaper 1 to Schedule B	Monthly Billing Units, Rates And Revenue	Historic Year December 31, 2024- Present Rates
3	Workpaper 2 to Schedule B	Sales Forecast Summary	Years Ended 12/31/2024, 12/31/2025 and 12/31/2026
3	Workpaper 2 to Schedule C	Historic O&M	Historic Year December 31, 2024
4	Workpaper 2 to Schedule C	Future O&M	Years 2025 and 2026
5	Workpaper 3 to Schedule C	Accumulated Deferred Income Taxes	Years 2017 through 2023
6	Workpaper 4 to Schedule C	Gas Inventory Balances	Years 2014 through 2024
7			

WP1_B

Valley Energy, Inc. (PA)
Rate Case with Fully Projected Future Test Year 2026
Workpaper 1 to Schedule B
Monthly Billing Units, Rates And Revenue
Historic Year December 31, 2024- Present Rates

Line			Rate R- Residential	Rate C- Commercial	Rate IS- Interruptible Service	Rate SI- Small Industrial	Rate ST- Transport Firm	Rate I Large Industrial Firm	Transport Firm- Contract	Transport. Firm- DDQ	Transport. Interruptible	Total
1							**BILLING UNITS**					
2							**ccf Sales Historic Year December 31, 2024**					
3	Jan-24		811,551	365,787	0	10,435	256,364		1,600,550	144,148	655,932	3,844,767
4	Feb-24		956,056	420,272	510	12,377	204,405		1,379,780	164,362	629,965	3,767,727
5	Mar-24		795,563	345,934	0	10,426	236,787		1,377,870	139,518	634,790	3,540,888
6	Apr-24		649,473	280,142	2,700	6,951	219,126		1,235,070	117,770	615,093	3,126,325
7	May-24		333,846	141,424	26,540	3,133	189,425		1,138,760	72,268	573,425	2,478,821
8	Jun-24		120,653	64,439	46,880	1,115	183,697		1,059,180	40,318	573,002	2,089,284
9	Jul-24		70,730	44,655	20,260	502	218,200		1,041,970	24,564	564,501	1,985,382
10	Aug-24		65,838	45,964	49,050	577	185,912		898,800	28,001	547,490	1,821,632
11	Sep-24		80,481	51,895	41,620	706	176,139		951,280	27,701	516,647	1,846,469
12	Oct-24		104,465	61,978	29,410	669	194,142		1,273,900	30,767	542,916	2,238,247
13	Nov-24		337,301	142,315	21,160	3,182	232,477		1,284,340	63,653	558,810	2,643,238
14	Dec-24		694,442	294,104	13,430	7,618	284,723		1,496,800	122,223	652,438	3,565,778
15			5,020,399	2,258,909	251,560	57,691	2,581,397	0	14,738,300	975,293	7,065,009	32,948,558
16	*Check to Forecast file*		*5,020,399*	*2,258,909*	*251,560*	*57,691*	*1,971,007*		*14,738,300*	*975,293*	*7,675,399*	*32,948,558*
17							**Customers Historic Year December 31, 2024**					
18	Jan-24		6,517	861	1	4	12		2	56	5	7,458
19	Feb-24		6,524	860	1	4	12		2	56	5	7,464
20	Mar-24		6,529	860	1	4	12		2	56	5	7,469
21	Apr-24		6,494	855	1	4	12		2	56	5	7,429
22	May-24		6,466	852	1	4	12		2	56	5	7,398
23	Jun-24		6,451	850	1	4	12		2	56	5	7,381
24	Jul-24		6,423	849	1	4	12		2	56	5	7,352
25	Aug-24		6,416	850	1	4	12		2	56	5	7,346
26	Sep-24		6,437	850	1	4	12		2	56	5	7,367
27	Oct-24		6,504	853	1	4	12		2	56	5	7,437
28	Nov-24		6,504	853	1	4	12		2	56	5	7,437
29	Dec-24		6,565	857	1	4	12		2	56	5	7,502
30	Annual Bills		77,830	10,250	12	48	144	0	24	672	60	89,040
31	Average Monthly Bills		6,486	854	1	4	12	0	2	56	5	7,420
32							**RATES AND CHARGES**					
33							**Tariff Rates**					
34	Customer Charge	Tariff	$12.35	$21.95	$82.00	$82.00	$82.00			$21.95	$82.00	
35												
36	Commodity Block 1		$0.37095	$0.27929	$0.086720	$0.186900	$0.186900	#######		$0.279290	$0.086720	
42	GCR Jan-Oct	$0.33758	$0.33758	$0.33758	$0.33758	$0.33758						
43	GCR Nov-Dec	$0.34569	$0.34569	$0.34569	$0.34569	$0.34569						

WP1_B

Valley Energy, Inc. (PA)
Rate Case with Fully Projected Future Test Year 2026
Workpaper 1 to Schedule B
Monthly Billing Units, Rates And Revenue
Historic Year December 31, 2024- Present Rates

Line		Rate R- Residential	Rate C- Commercial	Rate IS- Interruptible Service	Rate SI- Small Industrial	Rate ST- Transport Firm	Rate I Large Industrial Firm	Transport Firm- Contract	Transport. Firm- DDQ	Transport. Interruptible	Total
44		**COMPUTATION OF REVENUE**									
45		**Customer Charge Revenue**									
46	Jan-24	$80,485	$18,899	$82	$328	$984			$1,229	$410	$102,007
47	Feb-24	80,571	18,877	82	328	984			1,229	410	$102,072
48	Mar-24	80,633	18,877	82	328	984			1,229	410	$102,133
49	Apr-24	80,201	18,767	82	328	984			1,229	410	$101,591
50	May-24	79,855	18,701	82	328	984			1,229	410	$101,180
51	Jun-24	79,670	18,658	82	328	984			1,229	410	$100,951
52	Jul-24	79,324	18,636	82	328	984			1,229	410	$100,583
53	Aug-24	79,238	18,658	82	328	984			1,229	410	$100,518
54	Sep-24	79,497	18,658	82	328	984			1,229	410	$100,778
55	Oct-24	80,324	18,723	82	328	984			1,229	410	$101,671
56	Nov-24	80,324	18,723	82	328	984			1,229	410	$101,671
57	Dec-24	81,078	18,811	82	328	984			1,229	410	$102,512
58		$961,201	$224,988	$984	$3,936	$11,808	$0	$0	$14,750	$4,920	$1,217,666
59											
60		**Distribution ccf Revenue**									
61	Jan-24	$301,045	$102,161	$0	$1,950	$47,914		$76,270	$40,259	$56,882	$569,600
62	Feb-24	$354,649	$117,378	$44	$2,313	$38,203		$72,085	$45,905	$54,631	$630,577
63	Mar-24	$295,114	$96,616	$0	$1,949	$44,255		$70,384	$38,966	$55,049	$547,284
64	Apr-24	$240,922	$78,241	$234	$1,299	$40,955		$68,491	$32,892	$53,341	$463,034
65	May-24	$123,840	$39,498	$2,302	$586	$35,404		$65,517	$20,184	$49,727	$287,329
66	Jun-24	$44,756	$17,997	$4,065	$208	$34,333		$65,035	$11,260	$49,691	$177,656
67	Jul-24	$26,237	$12,472	$1,757	$94	$40,782		$62,614	$6,860	$48,954	$150,816
68	Aug-24	$24,423	$12,837	$4,254	$108	$34,747		$53,080	$7,820	$47,478	$137,269
69	Sep-24	$29,854	$14,494	$3,609	$132	$32,920		$64,033	$7,737	$44,804	$152,780
70	Oct-24	$38,751	$17,310	$2,550	$125	$36,285		$70,301	$8,593	$47,082	$173,916
71	Nov-24	$125,122	$39,747	$1,835	$595	$43,450		$72,832	$17,778	$48,460	$301,358
72	Dec-24	$257,603	$82,140	$1,165	$1,424	$53,215		$77,784	$34,136	$56,579	$507,467
73		$1,862,317	$630,891	$21,815	$10,782	$482,463	$0	$818,427	$272,390	$612,678	$4,099,085
74											

WP1_B

Valley Energy, Inc. (PA)
Rate Case with Fully Projected Future Test Year 2026
Workpaper 1 to Schedule B
Monthly Billing Units, Rates And Revenue
Historic Year December 31, 2024- Present Rates

Line		Rate R- Residential	Rate C- Commercial	Rate IS- Interruptible Service	Rate SI- Small Industrial	Rate ST- Transport Firm	Rate I Large Industrial Firm	Transport Firm- Contract	Transport. Firm- DDQ	Transport. Interruptible	Total
75						**GCR Revenue**					
76	Jan-24	$273,963	$123,482	$0	$3,523						$400,968
77	Feb-24	322,745	141,875	172	4,178						$468,971
78	Mar-24	268,566	116,780	0	3,520						$388,866
79	Apr-24	219,249	94,570	911	2,347						$317,077
80	May-24	112,700	47,742	8,959	1,058						$170,459
81	Jun-24	40,730	21,753	15,826	376						$78,686
82	Jul-24	23,877	15,075	6,839	169						$45,961
83	Aug-24	22,226	15,517	16,558	195						$54,495
84	Sep-24	27,169	17,519	14,050	238						$58,976
85	Oct-24	35,265	20,923	9,928	226						$66,342
86	Nov-24	116,602	49,197	7,315	1,100						$174,213
87	Dec-24	240,062	101,669	4,643	2,633						$349,007
88		$1,703,154	$766,102	$85,202	$19,563	$0	$0	$0	$0	$0	$2,574,021
89											
90						**Total Revenue**					
91	Jan-24	$655,493	$244,542	$82	$5,801	$48,898	$0	$76,270	$41,488	$57,292	$1,129,867
92	Feb-24	757,966	278,130	298	6,819	39,187	0	72,085	47,134	55,041	$1,256,661
93	Mar-24	644,313	232,273	82	5,796	45,239	0	70,384	40,195	55,459	$1,093,743
94	Apr-24	540,372	191,578	1,228	3,974	41,939	0	68,491	34,121	53,751	$935,454
95	May-24	316,395	105,942	11,343	1,971	36,388	0	65,517	21,413	50,137	$609,105
96	Jun-24	165,156	58,408	19,973	913	35,317	0	65,035	12,490	50,101	$407,393
97	Jul-24	129,438	46,182	8,678	591	41,766	0	62,614	8,090	49,364	$346,722
98	Aug-24	125,886	47,011	20,894	631	35,731	0	53,080	9,050	47,888	$340,170
99	Sep-24	136,520	50,670	17,741	698	33,904	0	64,033	8,966	45,214	$357,747
100	Oct-24	154,341	56,956	12,561	679	37,269	0	70,301	9,822	47,492	$389,420
101	Nov-24	322,048	107,667	9,232	2,023	44,434	0	72,832	19,007	48,870	$626,113
102	Dec-24	578,743	202,620	5,889	4,385	54,199	0	77,784	35,365	56,989	$1,015,975
103		$4,526,671	$1,621,980	$108,001	$34,281	$494,271	$0	$818,427	$287,140	$617,598	$8,508,370

Valley Energy, Inc. (PA)
Workpaper 2 to Schedule B
Sales Forecast Summary
Years Ended 12/31/2024, 12/31/2025 and 12/31/2026

	WP	Forecast YE2026 Avg # Cust	Forecast YE2026 Projected CCF 2026	Forecast YE2025 Avg # Cust	Forecast YE2025 Projected CCF 2025	Average Cust 2024	Actual CCF 2024	Actual CCF 2023	Actual CCF 2022	Actual CCF 2021	Actual CCF 2020	Actual CCF 2019	Actual CCF 2018	RSQ
Residential	2A	6,586	5,886,309	6,536	5,841,818	6,486	5,020,399	5,364,814	5,764,257	5,598,048	5,499,225	5,750,866	6,046,406	94.7%
Commercial	2B	851	2,566,623	851	2,566,623	854	2,258,909	2,434,724	2,628,745	2,495,606	2,372,356	2,618,051	2,704,420	94.0%
Industrial	2C	4	59,459	4	59,459	4	57,691	67,349	75,248	72,875	71,389	72,617	76,117	72.8%
Interruptible	2D	1	222,000	1	222,000	1	251,560	626,560	661,580	700,210	454,420	723,530	564,410	65.5%
DDQ-Transport	2E	56	947,972	56	947,972	56	975,293	1,017,689	947,227	947,195	897,448	904,564	927,322	92.0%
Transport-Firm	2F	13	17,528,029	13	17,528,029	13	16,709,307	17,188,282	17,270,061	17,776,902	15,904,382	17,787,714	19,254,897	See below
Transport-Intr	2G	4	4,139,559	4	4,139,559	5	4,031,939	3,509,306	3,333,192	3,451,487	3,776,522	3,573,215	3,535,110	44.3%
Rate I		1	3,581,019	1	3,581,019	1	3,643,460	3,635,090	3,559,650	3,450,210	3,504,100	3,573,070	3,626,630	59.3%
Total		7,516	34,930,969	7,466	34,886,478	7,420	32,948,558	33,843,814	34,239,960	34,492,533	32,479,842	35,003,627	36,735,312	
Volumes File							*32,948,558*	*33,843,814*	*34,239,960*	*34,492,533*	*32,479,842*	*35,003,627*	*37,358,316*	
Transport Firm														
Tariff		11	1,881,944	11	1,881,944	11	1,971,007	2,415,402	1,282,801	1,941,252	1,683,412	2,121,574	1,720,187	4.8%
Contract 1		1	8,470,343	1	8,470,343	1	8,382,960	8,412,330	8,808,220	8,670,950	7,495,560	8,487,030	8,686,820	54.1%
Contract 2		1	7,175,742	1	7,175,742	1	6,355,340	6,360,550	7,179,040	7,164,700	6,725,410	7,179,110	8,847,890	68.7%
			17,528,029		17,528,029		16,709,307	17,188,282	17,270,061	17,776,902	15,904,382	17,787,714	19,254,897	
HDD			6,393		6,393		5,643	5,575	6,385	5,827	5,916	6,825	7,207	

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Valley Energy, Inc. (PA)

Rate Case with Fully Projected Future Test Year 2026

Workpaper 2 to Schedule C

Historic O&M

Historic Year December 31, 2024

Line	Co.	Account		*rType24*	*rAcct24* Account	12 Month *rHTY24* Total
1	**PAYROLL - DIRECT LABOR**					
2	20	870.01	Labor Oper Supr & Eng	Labor	870	67,985
3	20	874.01	Labor Mains & Serv Exp	Labor	874	124,674
4	20	874.11	Emergency Labor Mains And Service Exp.	Labor	874	-3,566
5	20	875.01	Labor Meas & Reg Stat Exp	Labor	875	26,756
6	20	876.01	Labor Ind/Cm Mtr/Reg Mnt	Labor	876	31,469
7	20	877.01	Labor Meas & Reg City Gate	Labor	877	5,788
8	20	878.01	Labor Mtr/Hse Reg Exp	Labor	878	51,099
9	20	879.01	Labor Cust Install Exp	Labor	879	52,124
10	20	885.01	Labor Maint Supv & Eng	Labor	885	12,590
11	20	886.01	Labor Sturctures & Impr	Labor	886	8,422
12	20	887.01	Labor Maint Of Main	Labor	887	25,494
13	20	889.01	Labor Meas & Reg Stat Equip	Labor	889	31,185
14	20	890.01	Labor Maint. Indust. M&R Station	Labor	889	15,046
15	20	891.01	Labor Maint City Gate Stat	Labor	891	5,133
16	20	892.01	Labor Maint Of Service	Labor	892	14,017
17	20	893.01	Labor Maint Mtr & Hse Reg	Labor	893	19,753
18	20	902.01	Labor Meter Reading Exp	Labor	902	16,611
19	20	903.01	Labor Cust Rec/Collections	Labor	903	167,453
20	20	920.01	Labor Administration	Labor	920	236,771
21	20	932.01	Labor General Plt Maintenance	Labor	932	12,903
22	**Total Direct Labor**					**921,705**
23						

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Valley Energy, Inc. (PA)

Rate Case with Fully Projected Future Test Year 2026
Workpaper 2 to Schedule C
Historic O&M
Historic Year December 31, 2024

Line	Co.	Account		*rType24*	*rAcct24* Account	12 Month *rHTY24* Total
24	**TRANSPORTATION EXPENSES**					
25	20	870.02	Transp Oper Supr & Eng	Trans	870	2,517
26	20	874.02	Transp Mains & Service Exp	Trans	874	33,646
27	20	875.02	Trnsp Meas & Reg Stat Exp	Trans	875	8,105
28	20	876.02	Trans Ind/Cm/Mtr/Reg/Mnt	Trans	876	4,871
29	20	877.02	Transp Meas & Reg City Gate	Trans	877	1,717
30	20	878.02	Transp Mtr/Hse Reg Exp	Trans	878	12,497
31	20	879.02	Transp Cust Install Exp	Trans	879	7,771
32	20	885.02	Transp Maint Supv & Eng	Trans	885	1,188
33	20	886.02	Transp Maint Structures & Impr	Trans	886	1,306
34	20	887.02	Transp Maint Of Main	Trans	887	7,589
35	20	889.02	Transp Maint Meas/Reg Stat Eq	Trans	889	2,166
36	20	890.02	Transp Maint Indus M&R Stat	Trans	890	993
37	20	891.02	Transp Maint City Gate Stat	Trans	891	1,112
38	20	892.02	Transp Maint Of Service	Trans	892	6,441
39	20	893.02	Transp Maint Mtr Hse Reg	Trans	893	2,331
40	20	902.02	Trans Meter Reading Exp	Trans	902	2,679
41	20	903.02	Transp Cust Rec/Collections	Trans	903	2,980
42	20	920.02	Transp Adminstration	Trans	920	20,240
43	20	932.02	Trans Maint General Plant	Trans	932	7,822
44	**Total Trans. Exp**					**127,971**
45						

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Valley Energy, Inc. (PA)

Rate Case with Fully Projected Future Test Year 2026
Workpaper 2 to Schedule C
Historic O&M
Historic Year December 31, 2024

Line	Co.	Account		rType24	rAcct24 Account	12 Month rHTY24 Total
46	**C&T OVERHEAD**					
47	20	602.03	C&T OH Pto - Covid-19	OH	930CV	2,735
48	20	870.03	C&T OH Oper Supr & Eng	OH	870	15,833
49	20	874.03	C&T OH Mains & Service Exp	OH	874	28,987
50	20	875.03	C&T OH Meas & Reg Stat Exp	OH	875	6,197
51	20	876.03	C&T OH Ind/Cm Mtr/Reg Mnt	OH	876	7,292
52	20	877.03	C&T OH City Gate Meas/Reg Stat	OH	877	1,362
53	20	878.03	C&T OH Mtr/Hse Reg Exp	OH	878	11,989
54	20	879.03	C&T OH Cust Install Exp	OH	879	12,189
55	20	885.03	C&T OH Maint Supv & Eng	OH	885	2,941
56	20	886.03	C&T OH Maint Structures & Impr	OH	886	1,961
57	20	887.03	C&T OH Maint Of Main	OH	887	5,958
58	20	889.03	C&T OH Maint M&R Stat Equip	OH	889	7,143
59	20	890.03	C&T OH Maint Indust M&R Station Exp.	OH	889	3,521
60	20	891.03	C&T OH Maint City Gate Stat	OH	891	1,204
61	20	892.03	C&T OH Maint Services Exp	OH	892	3,670
62	20	893.03	C&T OH Maint Mtr & Hse Reg	OH	893	4,693
63	20	902.03	C&T OH Meter Reading Exp	OH	902	3,908
64	20	903.03	C&T OH Cust Rec/Collections	OH	903	39,035
65	20	920.03	C&T OH Adminstration	OH	920	54,972
66	20	932.03	C&T Ovhd General Plant	OH	932	2,959
67	**Total C&T OH**					**218,548**
68						

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Valley Energy, Inc. (PA)

Rate Case with Fully Projected Future Test Year 2026
Workpaper 2 to Schedule C
Historic O&M
Historic Year December 31, 2024

Line	Co.	Account		*rType24*	*rAcct24* Account	12 Month *rHTY24* Total
69	**VE LABOR OVERHEAD**					
70	20	602.05	VE OH Pto - Covid-19	OH	930CV	7,721
71	20	870.05	VE OH Oper Supr & Eng	OH	870	68,761
72	20	874.05	VE OH Mains & Service Exp	OH	874	131,510
73	20	875.05	VE OH Meas & Reg Stat Exp	OH	875	26,838
74	20	876.05	VE OH Ind/Cm/Mtr/Reg Mnt Exp	OH	876	33,626
75	20	877.05	VE OH City Gate Meas & Reg	OH	877	5,727
76	20	878.05	VE OH Mtr/Hse Reg Exp	OH	878	55,772
77	20	879.05	VE OH Cust Install Exp	OH	879	53,690
78	20	885.05	VE OH Maint Supv & Eng	OH	885	13,110
79	20	886.05	VE OH Maint Structures & Impr	OH	886	8,651
80	20	887.05	VE OH Maint Of Main	OH	887	26,482
81	20	889.05	VE OH Maint M&R Stat Equip	OH	889	29,440
82	20	890.05	VE OH Maint. Industr. M&R Station Exp.	OH	889	16,468
83	20	891.05	VE OH Maint City Gate Stat	OH	891	5,994
84	20	892.05	VE OH Maint Of Service	OH	892	16,917
85	20	893.05	Labor OH Maint Mtr & Hse Reg	OH	893	22,093
86	20	902.05	VE OH Meter Reading Exp	OH	902	17,267
87	20	903.05	VE OH Cust Rec/Collections	OH	903	172,384
88	20	920.05	VE OH Administration	OH	920	245,317
89	20	932.05	OH Maint Plant	OH	932	10,500
90	**Total VE Labor OH**					**968,267**
91						

WP1_C **Valley Energy, Inc. (PA)**

Rate Case with Fully Projected Future Test Year 2026
Workpaper 2 to Schedule C
Historic O&M
Historic Year December 31, 2024

Line	Co.	Account		*rType24*	*rAcct24* Account	12 Month *rHTY24* Total
92	**DIRECT O&M EXPENSES**					
93	20	602.0	Pto - Covid-19	Other	930CV	12,186
94	20	602.45	Mat/Sup Pto - Covid-19	Mat	930CV	2,979
95	20	842.1	Fuel (Company Use)	Other	842	26,245
96	20	871.45	Distrib Load Dispatching	Mat	871	1,063
97	20	874.45	Mat & Sup Mains & Serv Exp	Mat	874	34,996
98	20	874.5	Call Center Expense	Other	874	48,835
99	20	874.55	Mains & Serv Exp Emerg Acct	Other	874	(779)
100	20	875.45	Mat/Sup Meas & Reg Stat Exp	Mat	875	9,425
101	20	876.45	Mat & Sup Ind/Cm/Mtr/Reg/Mnt	Mat	876	4,795
102	20	877.45	Mat/Sup Citygate Meas/Reg Sta	Mat	877	29,048
103	20	878.45	Mat & Sup Mtr/Hse Reg Exp	Mat	878	4,024
104	20	879.45	Mat/Sup Cust Install Exp	Mat	879	1,800
105	20	880.45	Mat/Sup Other Distribution Exp	Mat	880	4,393
106	20	881.45	Rents - Distribution Expense	Other	881	4,773
107	20	886.45	Mat/Sup Maint Structure/Impr	Mat	886	1,602
108	20	887.45	Mat/Supp Maint Of Main	Mat	887	20,015
109	20	887.99	Maint Main Material Written Off	Other	887	(19)
110	20	889.45	Mat/Sup Maint M&R Stat Equip	Mat	889	9,896
111	20	890.45	Mat/Sup Maint M&R Indust Equip	Mat	890	10,406
112	20	891.45	Mat/Sup Maint City Gate Stat	Mat	891	1,827
113	20	892.0	Maint Of Services	Other	892	10
114	20	892.45	Mat/Sup Maint Of Services	Mat	892	18,480
115	20	893.45	Mat/Supp Maint Mtr & Hse Reg	Mat	893	13,564
116	20	893.99	Maint Mtr Material Written Off	Other	893	346
117	20	902.45	Mat/Supp Meter Reading Exp	Mat	902	2,483
118	20	903.25	NISC Billing	Other	903	107,070
119	20	903.45	Mat/Sup Cust Rec/Collections	Other	903	50,321

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Valley Energy, Inc. (PA)

Rate Case with Fully Projected Future Test Year 2026
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Line	Co.	Account		*rType24*	*rAcct24* Account	12 Month *rHTY24* Total
120	20	903.55	Dollar Energy Fund Expenses	Other	903	5,618
121	20	904.0	Bad Debt Expense	Other	904	(19,622)
122	20	905.45	Mat/Sup Misc Cust Acct Exp	Mat	905	22,877
123	20	909.45	Information/Instructional Exp	Other	909	7,633
124	20	913.45	Advertising Expenses	Other	913	4,409
125	20	920.45	Mat/Sup Administrative	Mat	920	644
126	20	921.0	General Office Supplies & Exp	Other	921	12,122
127	20	921.4	Meal Expenses	Other	921	2,511
128	20	921.45	Travel And Training	Mat	921	18,552
129	20	921.5	Communication Equip	Other	921	11,714
130	20	923.0	Outside Services Employed	Other	923	19,142
131	20	923.25	Auditor Fees Expense	Other	923	29,692
132	20	923.4	Gcr Expense	Other	923	3,059
133	20	923.45	Attorney Fees Expense	Other	923	7,433
134	20	924.0	Property Insurance Expense	Other	924	16,358
135	20	925.0	Injuries And Damages	Other	925	85,979
136	20	925.1	Insurance St Opening Bonds	Other	925	1,160
137	20	926.45	Employee Benefits-Direct Exp.	Other	926	11,387
138	20	928.0	Regulatory Commission Expenses	Other	928	122,392
139	20	930.2	Miscellaneous General Expense	Other	930	1,325
140	20	930.22	Dues/Company Memberships	Other	930	17,490
141	20	930.25	Director Expense	Other	930	48,980
142	20	932.45	Maint General Plant	Other	932	4,289
143	**Total Direct Expenses**					**854,928**
144						3,091,419
				Other		642,059
				Mat		212,869
						854,928

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Valley Energy, Inc. (PA)
Rate Case with Fully Projected Future Test Year 2026
Workpaper 2 to Schedule C
Future O&M
Years 2025 and 2026

Line	Dept.	Account	rType22	rAcct25	rFTY25 Total 2025	rFPFTY26 Total 2026
1	**PAYROLL - DIRECT LABOR**					
2	LABOR OPER SUPR & ENG	870.01	Labor	870	103,788	113,359
3	LABOR MAINS & SERV EXP	874.01	Labor	874	136,278	193,236
4	LABOR MEAS & REG STAT EXP	875.01	Labor	875	35,758	40,056
5	LABOR IND/CM MTR/REG MNT	876.01	Labor	876	31,539	36,372
6	LABOR MEAS & REG CITY GATE	877.01	Labor	877	6,288	7,065
7	LABOR MTR/HSE REG EXP	878.01	Labor	878	60,218	67,498
8	LABOR CUST INSTALL EXP	879.01	Labor	879	72,453	80,239
9	LABOR OQ TRAINING	880.01	Labor	880	20,603	27,982
10	LABOR MAINT SUPV & ENG	885.01	Labor	885	15,514	16,318
11	LABOR STURCTURES & IMPR	886.01	Labor	886	7,488	6,038
12	LABOR MAINT OF MAIN	887.01	Labor	887	36,769	43,282
13	LABOR MEAS & REG STAT EQUIP	889.01	Labor	889	20,343	18,035
14	LABOR MAINT. INDUST. M&R STATION	890.01	Labor	890	8,837	10,141
15	LABOR MAINT CITY GATE STAT	891.01	Labor	891	1,715	1,979
16	LABOR MAINT OF SERVICE	892.01	Labor	892	20,480	26,012
17	LABOR MAINT MTR & HSE REG	893.01	Labor	893	29,166	23,748
18	LABOR METER READING EXP	902.01	Labor	902	9,734	6,193
19	LABOR CUST REC/COLLECTIONS	903.01	Labor	903	214,654	229,723
20	LABOR ADMINISTRATION	920.01	Labor	920	276,347	298,043
21	LABOR GENERAL PLT MAINTENANCE	932.01	Labor	932	8,168	8,203
22	**Total Direct Labor**				**1,116,140**	**1,253,522**
23						
24	TRANSP OPER SUPR & ENG	870.02	Trans	870	8,447	8,700
25	TRANSP MAINS & SERVICE EXP	874.02	Trans	874	30,734	31,656
26	TRNSP MEAS & REG STAT EXP	875.02	Trans	875	8,638	8,897
27	TRANS IND/CM/MTR/REG/MNT	876.02	Trans	876	4,480	4,614
28	TRANSP MEAS & REG CITY GATE	877.02	Trans	877	2,640	2,719
29	TRANSP MTR/HSE REG EXP	878.02	Trans	878	8,833	9,098
30	TRANSP CUST INSTALL EXP	879.02	Trans	879	11,297	11,636
31	TRANSP OQ TRAINING	880.02	Trans	880	136	140
32	TRANSP MAINT SUPV & ENG	885.02	Trans	885	3,271	3,369
33	TRANSP MAINT STRUCTURES & IMPR	886.02	Trans	886	653	673
34	TRANSP MAINT OF MAIN	887.02	Trans	887	5,210	5,366
35	TRANSP MAINT MEAS/REG STAT EQ	889.02	Trans	889	1,461	1,505
36	TRANSP MAINT INDUS M&R STAT	890.02	Trans	890	212	218
37	TRANSP MAINT CITY GATE STAT	891.02	Trans	891	756	779
38	TRANSP MAINT OF SERVICE	892.02	Trans	892	7,657	7,887
39	TRANSP MAINT MTR HSE REG	893.02	Trans	893	2,134	2,198
40	TRANS METER READING EXP	902.02	Trans	902	2,499	2,574
41	TRANSP CUST REC/COLLECTIONS	903.02	Trans	903	3,923	4,041
42	TRANSP ADMINSTRATION	920.02	Trans	920	18,770	19,333
43	TRANS MAINT GENERAL PLANT	932.02	Trans	932	1,518	1,564
44	**Total Trans. Exp**				**123,269**	**126,967**
45						

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Valley Energy, Inc. (PA)
Rate Case with Fully Projected Future Test Year 2026
Workpaper 2 to Schedule C
Future O&M
Years 2025 and 2026

			rType22	*rAcct25*	*rFTY25*	*rFPFTY26*
Line	**Dept.**	**Account**			**Total 2025**	**Total 2026**
46	C&T OH OPER SUPR & ENG	870.03	OH	870	26,794	29,264
47	C&T OH MAINS & SERVICE EXP	874.03	OH	874	35,181	49,885
48	C&T OH MEAS & REG STAT EXP	875.03	OH	875	9,231	10,341
49	C&T OH IND/CM MTR/REG MNT	876.03	OH	876	8,142	9,390
50	C&T OH CITY GATE MEAS/REG STAT	877.03	OH	877	1,623	1,824
51	C&T OH MTR/HSE REG EXP	878.03	OH	878	15,546	17,425
52	C&T OH CUST INSTALL EXP	879.03	OH	879	18,704	20,714
53	C&T OH OQ TRAINING	880.03	OH	880	5,319	7,224
54	C&T OH MAINT SUPV & ENG	885.03	OH	885	4,005	4,213
55	C&T OH MAINT STRUCTURES & IMPR	886.03	OH	886	1,933	1,559
56	C&T OH MAINT OF MAIN	887.03	OH	887	9,492	11,174
57	C&T OH MAINT M&R STAT EQUIP	889.03	OH	889	5,252	4,656
58	C&T OH MAINT INDUST M&R STATION E	890.03	OH	890	2,281	2,618
59	C&T OH MAINT CITY GATE STAT	891.03	OH	891	443	511
60	C&T OH MAINT SERVICES EXP	892.03	OH	892	5,287	6,715
61	C&T OH MAINT MTR & HSE REG	893.03	OH	893	7,529	6,131
62	C&T OH METER READING EXP	902.03	OH	902	2,513	1,599
63	C&T OH CUST REC/COLLECTIONS	903.03	OH	903	55,414	59,305
64	C&T OH ADMINSTRATION	920.03	OH	920	71,341	76,942
65	C&T OVHD GENERAL PLANT	923.03	OH	920	2,109	2,118
66	**Total C&T OH**				**288,139**	**323,605**
67						
68	VE OH OPER SUPR & ENG	870.05	OH	870	100,001	109,223
69	VE OH MAINS & SERVICE EXP	874.05	OH	874	131,306	186,186
70	VE OH MEAS & REG STAT EXP	875.05	OH	875	34,453	36,913
71	VE OH IND/CM/MTR/REG MNT EXP	876.05	OH	876	30,388	34,862
72	VE OH CITY GATE MEAS & REG	877.05	OH	877	6,059	6,475
73	VE OH MTR/HSE REG EXP	878.05	OH	878	58,021	63,918
74	VE OH CUST INSTALL EXP	879.05	OH	879	69,810	76,507
75	VE OH OQ TRAINING	880.03	OH	880	19,851	26,556
76	VE OH MAINT SUPV & ENG	885.05	OH	885	14,948	15,723
77	VE OH MAINT STRUCTURES & IMPR	886.05	OH	886	7,215	2,498
78	VE OH MAINT OF MAIN	887.05	OH	887	35,428	41,703
79	VE OH MAINT M&R STAT EQUIP	889.05	OH	889	19,601	8,839
80	VE OH MAINT. INDUSTR. M&R STATION	890.05	OH	890	8,515	9,482
81	VE OH MAINT CITY GATE STAT	891.05	OH	891	1,652	1,907
82	VE OH MAINT OF SERVICE	892.05	OH	892	19,733	25,063
83	LABOR OH MAINT MTR & HSE REG	893.05	OH	893	28,102	7,931
84	VE OH METER READING EXP	902.05	OH	902	9,379	2,522
85	VE OH CUST REC/COLLECTIONS	903.05	OH	903	206,823	218,985
86	VE OH ADMINISTRATION	920.05	OH	920	266,265	287,169
87	OH MAINT PLANT	932.05	OH	932	7,870	5,527
88	**Total VE Labor OH**				**1,075,419**	**1,167,988**
89						
90						

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Valley Energy, Inc. (PA)
Rate Case with Fully Projected Future Test Year 2026
Workpaper 2 to Schedule C
Future O&M
Years 2025 and 2026

Line	Dept.	Account	*rType22*	*rAcct25*	*rFTY25* Total 2025	*rFPFTY26* Total 2026
91	FUEL (COMPANY USE)	842.10	Other	842	21,130	20,347
92	DISTRIB LOAD DISPATCHING	871.45	Mat	871	6,763	7,101
93	MAT & SUP MAINS & SERV EXP	874.45	Mat	874	32,675	32,675
94	CALL CENTER EXPENSE	874.50	Other	874	74,285	76,514
95	TOOLS, EQUIPMENT & MAINTENANCE	874.99	Mat	874	10,029	10,330
96	MAT/SUP MEAS & REG STAT EXP	875.45	Mat	875	10,207	10,513
97	MAT & SUP IND/CM/MTR/REG/MNT	876.45	Mat	876	7,968	9,164
98	MAT/SUP CITYGATE MEAS/REG STA	877.45	Mat	877	13,637	14,046
99	MAT & SUP MTR/HSE REG EXP	878.45	Mat	878	1,634	1,683
100	MAT/SUP CUST INSTALL EXP	879.45	Mat	879	920	947
101	MAT/SUP OQ TRAINING	880.45	Mat	880	8,526	8,782
102	RENTS - DISTRIBUTION EXPENSE	881.45	Mat	881	6,222	6,669
103	MAT/SUP MAINT STRUCTURE/IMPR	886.45	Mat	886	9,176	9,451
104	MAT/SUPP MAINT OF MAIN	887.45	Mat	887	31,010	31,940
105	MAT/SUP MAINT M&R STAT EQUIP	889.45	Mat	889	18,998	19,568
106	MAT/SUP MAINT M&R INDUST EQUIP	890.45	Mat	890	3,718	3,830
107	MAT/SUP MAINT CITY GATE STAT	891.45	Mat	891	3,323	7,616
108	MAT/SUP MAINT OF SERVICES	892.45	Mat	892	5,440	5,604
109	MAT/SUPP MAINT MTR & HSE REG	893.45	Mat	893	13,945	14,364
110						
111	MAT/SUPP METER READING EXP	902.45	Mat	902	3,981	4,100
112	NISC BILLING	903.25	Other	903	111,397	112,891
113	MAT/SUP CUST REC/COLLECTIONS	903.45	Mat	903	29,837	30,732
114	DOLLAR ENERGY FUND EXPENSES	903.55	Other	903	5,927	5,927
115	BAD DEBT EXPENSE	904.00	Other	904	50,495	54,348
116	MAT/SUP MISC CUST ACCT EXP	905.45	Mat	905	21,492	21,492
117	INFORMATION/INSTRUCTIONAL EXP	909.45	Mat	909	12,774	13,157
118	ADVERTISING EXPENSES	913.45	Mat	913	2,057	2,098
119						
120	MAT/SUP ADMINISTRATIVE	920.45	Mat	920	68	69
121	GENERAL OFFICE SUPPLIES & EXP	921.00	Other	921	12,054	12,054
122	MEAL EXPENSES	921.40	Other	921	9,132	9,406

WP2_C

Valley Energy, Inc. (PA)
Rate Case with Fully Projected Future Test Year 2026
Workpaper 2 to Schedule C
Future O&M
Years 2025 and 2026

Line	Dept.	Account	rType22	rAcct25		rFTY25 Total 2025	rFPFTY26 Total 2026
123	TRAVEL AND TRAINING	921.45	Other		921	40,834	42,059
124	COMMUNICATION EQUIP	921.50	Other		921	17,350	17,871
125	OUTSIDE SERVICES EMPLOYED	923.00	Other		923	25,452	26,215
126	AUDITOR FEES EXPENSE	923.25	Other		923	43,735	47,233
127	GCR EXPENSE	923.40	Other		923	3,321	3,487
128	ATTORNEY FEES EXPENSE	923.45	Other		923	8,152	8,560
129	INSURANCE ST OPENING BONDS	925.10	Other		925	500	500
130	PROPERTY INSURANCE EXPENSE	924.00	Other		924	36,257	41,699
131	INJURIES AND DAMAGES	925.00	Other		925	108,157	124,381
132	EMPLOYEE BENEFITS-DIRECT EXP.	926.45	Other		926	9,898	10,194
133	REGULATORY COMMISSION EXPENSES	928.00	Other		928	99,514	105,514
134	MISCELLANEOUS GENERAL EXPENSE	930.20	Other		930	28,363	30,751
135	LABOR - VOLUNTEER	930.21	Other		930	187	216
136	DUES/COMPANY MEMBERSHIPS	930.22	Other		930	16,791	17,295
137	COVID-Related	930CV	Other	930CV		-	-
138	DIRECTOR EXPENSE	930.25	Other		930	58,639	57,047
139	DIRECTOR EXP. - TRAVEL/TRAINING	930.45	Other		930	-	1,309
140	MAINT GENERAL PLANT	932.45	Mat		932	23,249	23,946
141	**Total Direct Expenses**					**1,059,219**	**1,115,695**
142						3,662,186	3,987,778
143						3,662,186	3,987,778
144						3,662,186	3,987,778
145							
146							
147			Other			781,570	825,818
148			Mat			277,649	289,877
149						1,059,219	1,115,695

WP3_C

Valley Energy, Inc. (PA)
Rate Case with Fully Projected Future Test Year 2026
Workpaper 3 to Schedule C
Accumulated Deferred Income Taxes
Years 2017 through 2023

Line	Valley PA	2024	2025	2026
1				
2				
3	Book	20,753,495	22,356,239	24,061,709
4				
5	Federal Tax - MACRS	39,787,591	41,500,668	43,353,900
6				
7	Federal Tax - SL	37,481,985	39,313,415	41,266,769
8				
9	PA Tax	31,804,320	33,607,026	36,524,778
10				
11	Federal Tax Depr Exp - MACRS	1,515,837	1,723,903	1,878,388
12				
13	Federal Tax Depr Exp - SL	1,763,836	1,842,256	1,978,510
14				
15	PA Tax Depr Exp	2,115,013	2,528,871	2,227,569

WP4_C

Valley Energy, Inc. (PA)
Rate Case with Fully Projected Future Test Year 2026
Workpaper 4 to Schedule C
Gas Inventory Balances
Years 2014 through 2024

Line	Volumes dth	Average	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
1	January	308,104	239,316	316,185	324,010	303,966	288,448	262,049	348,294	345,770	303,388	361,839	295,881
2	February	211,139	137,330	205,138	216,106	205,227	199,441	162,488	235,743	230,927	215,472	295,748	218,910
3	March	136,269	73,110	87,111	123,140	104,509	90,857	82,198	221,307	180,789	130,668	238,899	166,375
4	April	174,267	102,115	134,840	161,039	158,026	140,091	133,872	249,101	222,236	151,635	265,765	198,220
5	May	239,064	164,566	199,779	229,451	219,484	208,626	200,548	315,055	284,125	223,061	319,327	265,678
6	June	307,529	235,210	272,102	296,747	299,653	270,023	269,114	374,779	352,519	292,226	383,864	336,583
7	July	373,837	310,689	343,498	369,243	377,771	348,425	343,384	416,525	428,834	359,138	436,959	377,736
8	August	436,884	380,552	415,982	440,488	447,551	409,464	415,442	469,372	485,143	428,867	484,617	428,250
9	September	501,109	458,095	480,148	510,136	509,996	490,264	479,213	549,092	530,928	504,539	509,438	490,348
10	October	534,969	533,294	529,372	533,064	538,540	522,002	540,177	554,292	560,526	548,887	521,062	503,443
11	November	508,017	517,763	507,262	509,242	500,821	476,879	509,961	553,870	536,555	523,727	489,542	462,568
12	December	429,430	446,279	436,961	421,771	410,292	394,290	429,939	459,074	470,770	446,356	443,121	364,873
13													
14													
15	**Average volu**	**346,718**	dth										
16	GCR at Preser	$3.45690	per dth										
17	**Inventory Va**	**1,198,570**											
18													

BEFORE

THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	**:**	
	:	
v.	**:**	**Docket No. R-2025-3054393**
	:	
Valley Energy, Inc.	**:**	

REBUTTAL TESTIMONY

AND EXHIBIT

OF

HOWARD S. GORMAN

ON BEHALF OF

VALLEY ENERGY, INC.

AUGUST 13, 2025

BEFORE

THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	**Docket No. R-2025-3054393**
	:	
Valley Energy, Inc.	:	

REBUTTAL TESTIMONY OF HOWARD S. GORMAN ON BEHALF OF VALLEY ENERGY, INC.

Q. Please state your name, occupation and business address.

A. My name is Howard Gorman. I am the President of HSG Group, Inc., a consulting firm specializing in utility rate and regulatory matters, located in Great Neck, NY.

Q. Are you the same Howard Gorman that provided direct testimony on behalf of Valley Energy, Inc. ("Valley" or "Company")?

A. Yes. Terms defined in my direct testimony have the same meaning in this rebuttal testimony.

Q. What is the purpose of your testimony today?

A. The purpose of my testimony is to rebut the testimony of the following witnesses:

- Bureau of Investigation and Enforcement ("I&E") Witness Wilson (I&E St. No. 1), regarding Pennsylvania Corporate Income Tax rate, Rate Case expense, Unamortized Rate Case expense, Regulatory Commission expense and Cash Working Capital.
- I&E Witness Sakaya (I&E St. No. 3) regarding Scale Back and Customer Charges.
- Office of Consumer Advocate ("OCA") Witness Meyer (OCA St. No. 1) regarding Depreciation Expense.
- OCA Witness Deupree (OCA St. No. 3) regarding Revenue Allocation and Customer Charges.

- Office of Small Business Advocate ("OSBA") Witness Farr (OSBA St. No. 1), regarding Pennsylvania Corporate Income Tax rate and Uncollectibles expense.

Q. Are you sponsoring any exhibits today?

A. Yes, I am sponsoring Exhibit___(HSG-1R), which includes an index on Schedule A (R). The Company is supporting an increase of $1,285,942 compared to $1,626,099 in its original filing, reflecting the changes shown in Table HSG-1:

Line	Table HSG-1	Revenue Increase
1	Company's Original Filing	1,626,099
2	Update PA Tax rates	(30,798)
3	Remove $58,195 from Account 928	(59,494)
4	Remove $161,942 Depreciation expense from Account 391	(206,688)
5	Remove $199 Depreciation expense from Account 396	(254)
6	Remove GCR costs from Account 923	(3,565)
7	Remove costs from Accounts 923, 930	(3,367)
8	Reduce 925 for Lower Insurance cost	(31,673)
9	Reduce 930 for Advertising / Dues	(1,374)
10	Reduce 924 for Property Insurance	(2,944)
11		1,285,942

These changes to the revenue requirement are the result of adjustments suggested by the witnesses and adjustments that the Company identified as being appropriate during the discovery process.

Items Raised in Direct Testimony and Discussed Below

- PA Corporate Income tax rate - Change to 7.49% in 2026.
- Regulatory Commission Expense - Remove $58,195 which was included in error.
- Depreciation Expense - Remove $161,942 depreciation expense for Account 391 and $199 depreciation expense for Acct 396.
- Cash Working Capital - Adjust the allowance in Rate Base to equal 1/8 times applicable expenses.
- Revenue Allocation and Rate Design - Revenue Allocation and Rate Design were updated for the revenue requirement on Exhibit___(HSG-1R), Schedule C1 (R).

Items Identified During Discovery and Voluntarily Corrected

- Remove GCR costs from Account 923 - Company's response to I&E-RE-40.
- Remove costs from Accounts 923, 930 - Company's response to I&E-RE-40.

Items Discussed In Rebuttal Testimony of Other Company Witnesses

- Reduce Account 925 due to lower Insurance policy cost (Valley St. No. 5R).
- Reduce Account 925 due to removal of Advertising/Dues (Valley St. No. 5R).
- Reduce Account 924 for Property Insurance (Valley St. No. 5R).

I&E Witness Wilson

PA Corporate Income Tax Rate

Q. What does Ms. Wilson propose regarding the PA Corporate Income Tax rate?

A. Ms. Wilson notes that pursuant to Pennsylvania House Bill 1342 and Act 53 of 2022, the PA Corporate Income Tax rate is 8.49% in 2024, 7.99% in 2025 and 7.49% in 2026, with annual reductions of 0.5% until it reaches 4.99% in 2031 (I&E St. No. 1, p. 31). The Company agrees with this adjustment. The correct rates, as proposed by Ms. Wilson, are reflected in the Company's Rebuttal filing, Exhibit___(HSG-1R), Schedule C-1 (R).

Rate Case Expense

Q. What does Ms. Wilson propose regarding the Rate Case Expense?

A. Ms. Wilson proposes to normalize Rate Case Expense over 60 months, compared to the Company's proposed 36 months (I&E St. No. 1, p. 9). She cites the Company's average frequency of filing since 2010 in support of her 60-month normalization period. The Company does not agree with this adjustment.

Ms. Wilson's testimony discusses the Company's filing frequency since 2010; however, that average reflects that the Company did not file a rate case from 2010-2019. Prior to the

2010 rate case, the Company filed rate cases in 2004 and 2007. The long gap from 2010 to 2019 was due to the Moxie project, which provided incremental revenue to the Company. The Company explained the reasons for the abnormal filing gap in the fully-litigated 2019 rate case and was granted a 3-year normalization period in the Commission's Order (Docket No. R-2019-3008209). Since the 2019 rate case, the Company has filed rate cases in 2022 and 2025. The Company expects that going forward, it will need to file a rate case every 3 years (36 months). There is no reason to depart from the Commission's 2019 Order given the Company's overall history and future projections. This adjustment should be rejected by the Commission, and the Company's 3-year normalization period should be accepted.

Unamortized Rate Case Expense

Q. What does Ms. Wilson propose regarding Unamortized Rate Case Expense?

A. Ms. Wilson proposes removing Unamortized Rate Case expense from rate base, on the grounds that Rate Case expense is a normal operating expense for a utility, and the utility should not earn a return on a normal operating expense (I&E St. No. 1, p. 13).

Q. Do you agree?

A. No. The utility has working capital tied up in unrecovered Rate Case expense and is entitled to a return on that working capital. The Company pays the rate case expense on a real-time basis during the proceeding, then collects the projected amount included in the rate case expense claim over the normalization period without carrying charges. As such, allowing the return on the balance is necessary to compensate Valley for the delay between paying the expense and receiving the compensation in post-proceeding distribution revenues.

This treatment is analogous to Materials and Supplies, where the Company has laid out or committed working capital and the item has not flowed through expense yet. The cost of unused Materials and Supplies is routinely included in rate base. For the same reason, the unrecovered portion of Rate Case expense should be included as well, and this adjustment should be rejected.

Regulatory Commission Expense (Account 928)

Q. What does Ms. Wilson propose regarding Regulatory Commission Expense?

A. Ms. Wilson identifies an amount of $58,195 in this account that was included by mistake, and she proposes reducing the Company's Regulatory Commission Expense by this amount (I&E St. No. 1, p. 16). The Company agrees and has reduced Regulatory Commission Expense by this amount in its Rebuttal filing, Exhibit___(HSG-1R), Schedule C1-1 (R).

Cash Working Capital

Q. What does Ms. Wilson propose regarding Cash Working Capital?

A. Ms. Wilson proposes that the Cash Working Capital ("CWC") allowance be computed based on the Commission's determination of expenses in this case (I&E St. No. 1, p. 30). She appears to accept the Company's use of the 1/8 convention in computing CWC. The Company agrees that the CWC claim should reflect the approved expenses. Valley has adjusted its CWC claim in Rebuttal using the 1/8 convention and will use this approach for the final revenue requirement. The Company accepts this proposal, and it has been reflected in that amount in its Rebuttal exhibits (Exhibit___(HSG-1R)).

I&E Witness Sakaya

Revenue Allocation / Scale Back

Q. What does Mr. Sakaya recommend regarding Revenue Allocation/Scale Back?

A. Mr. Sakaya recommends "scaling back the rates so each class receives the same percentage increase" (I&E St. No. 3, p. 8), except for the contract rates which will remain as negotiated. This is what the Company proposed in its filing, and the Company agrees with the recommendation to give each class an equal percentage increase if the Commission authorizes a lower increase than the Company requested, with the understanding that this would not apply to contract customers; the rates for contract customers would be determined by the applicable contracts.

Customer Charges

Q. What does Mr. Sakaya recommend regarding Customer Charges?

A. Mr. Sakaya recommends that the proposed Customer Charges also be "included in the scale back" (I&E St. No. 3, p. 9). His reasons are to limit the increase to zero- and low-usage customers, to encourage conservation, and possibly to reflect cost of service. In proposing customer charges, the Company balances several issues: cost of service, conservation, rate and revenue stability, and affordability. As Mr. Rogers discusses in his Rebuttal Testimony, the Companies' peer group of mid- to large-sized Pennsylvania natural gas distribution companies generally have current customer charges that are higher than Valley's proposal. It is important to ensure that an appropriate portion of Valley's revenues are collected through the monthly customer charge to support revenue stability, considering variable weather conditions that would impact monthly usage. Valley's customer charges

should not be included in the scale back if the Company receives less than the full increase it requested.

OCA Witness Meyer

Depreciation Expense

Q. What adjustments to Depreciation Expense does Mr. Meyer propose?

A. Mr. Meyer proposes two adjustments to Depreciation expense.

- Office Furniture and Equipment, Account 391 (OCA St. No. 1, p. 13) - Mr. Meyer notes that this account was fully depreciated as of December 31, 2025, and proposes that no depreciation expense be allowed in 2026. The Company accepts this adjustment and has reflected it on Exhibit___(HSG-1R), Schedule C-3 (R).
- Power Operated Equipment, Account 396 (OCA St. No. 1, p. 14) - Mr. Meyer notes that this item will be fully depreciated by December 31, 2026, and proposes to depreciate the net book value as of December 31, 2025, over three years. Mr. Meyer's proposed treatment is incorrect and contrary to ratemaking principles. He did not present a deprecation study to support extending the depreciable life of this item. His rationale, that this will prevent overcollection of depreciation expense in years after 2026, ignores any capital spending the Company will do to replace this fully depreciated equipment. The rate year is 2026, and it would be inequitable to consider that there is no depreciable book value in later years, while ignoring additional capital spending. Mr. Meyer's proposed adjustment must be limited to the $199 negative net book value that he identified at December 31, 2026.

OCA Witness Deupree

Revenue Allocation

Q. What does Mr. Deupree recommend regarding Revenue Allocation?

A. Mr. Deupree finds the Company's "proposed equal allocation of its proposed revenue increase … to be reasonable" (OCA St. No. 3, p. 3).

Customer Charges

Q. What does Mr. Deupree recommend regarding Customer charges?

A. Mr. Deupree recommends the Commission reject the Company's proposed increases in Customer charges, and if the Commission authorizes an increase to the Customer charge, then the percentage increase should be no more than the system average overall increase (OCA St. No. 3, p. 11). He cites several reasons, which I address below.

- Support for Customer charges - Mr. Deupree is correct that the Company has not performed an Allocated Class Cost of Service Study ("ACOS") to support the proposed Customer charges. An ACOS is not necessary to evaluate the appropriate customer charges for Valley. Also, there is no ACOS to support revenue allocation, and various witnesses, including Mr. Deupree, have commented on (and uniformly supported) the Company's proposed revenue allocation. The lack of a cost study cannot be a bar to evaluating the appropriate Customer charges.
- Comparison to other regional utilities - Mr. Deupree claims the Company's proposed Customer charges for Residential and Commercial customers are higher the average for his peer group of regional utilities. My conclusion differs from Mr. Deupree's. Valley's proposed $14.00 Residential charge is close to his average of $13.79 (1.5% higher), and Valley's proposed $25.00 Commercial charge is a little higher than his

average of $22.65 (10.4% higher). However, these results account for the rate environment existing just after Valley's rate case; we do not know when the other utilities will file rate cases and what they will propose for Customer charges. My conclusion from reviewing this information is that Valley's proposed Customer charges are comfortably within the range of the present, and likely future, Customer charges of regional utilities. Moreover, as Mr. Rogers discusses, Valley's proposed customer charges are consistent with Pennsylvania natural gas utilities, which is a more relevant peer group.

- Effect on energy conservation and low-usage customers - Mr. Deupree claims that higher Customer charges are contrary to the goal of energy conservation. However, the goal of energy conservation should not be considered in a vacuum; rate design must balance this with concerns such as revenue stability for the utility and efficient price signals, as well as affordability. This is especially important for a weather-sensitive utility product such as natural gas. Inefficient pricing and under-recovery of costs lead to more frequent rate cases and also to cross-subsidies within rate classes, as costs are shifted to higher-usage customers.

Q. What do you recommend?

A. I recommend the Commission accept the Company's proposed Customer charges because they reflect a reasonable balance of the factors to be considered, and they are comfortably within the range of the present, and likely future, Customer charges of regional utilities. In his Rebuttal Testimony, Mr. Rogers discusses why the comparison group used by Mr. Deupree is not appropriate for Valley. I also note that the proposed increases to the

Customer charges are below the overall system average increase, as Mr. Deupree recommended.

OSBA Witness Farr

PA Corporate Income Tax Rate

Q. What does Mr. Farr propose regarding PA Corporate Income Tax Rate?

A. Mr. Farr makes the same proposal as Ms. Wilson regarding the PA Corporate Income Tax rate (OSBA St. No. 1, pp. 5-7), and as discussed above the correct rates are reflected in the Company's Rebuttal filing, Exhibit___(HSG-1R), Schedule C-1 (R).

Uncollectibles Expense

Q. What does Mr. Farr propose regarding Uncollectibles expense?

A. Mr. Farr's Table JBF-1 (OSBA St. No. 1, p. 4) has a decrease in Uncollectibles expense of $2,628. He offers no support for this proposed change, and it should be rejected by the Commission.

Q. Does this conclude your Rebuttal Testimony today?

A. Yes.

BEFORE

THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	**:**	
	:	
v.	**:**	**Docket No. R-2025-3054393**
	:	
Valley Energy, Inc.	**:**	

EXHIBIT

OF

HOWARD S. GORMAN

ON BEHALF OF

VALLEY ENERGY, INC.

AUGUST 13, 2025

Valley Energy, Inc. (PA)
Rate Case with Fully Projected Future Test Year 2026 (R)
INDEX TO SCHEDULES

Line	SCHEDULE	DESCRIPTION	PERIOD
1	A (R)	INDEX TO SCHEDULES	
2			
3		**RATES AND REVENUE**	
4	B (R)	Operating Revenue Under Present Rates and Proposed Rates	Years Ended 12/31/2024, 12/31/2025 and 12/31/2026
5	B1 (R)	Summary Of Sales, Customers And Revenue At Present Rates	Historic Year December 31, 2024
6	B1-1 (R)	Billing Units, Rates And Revenue At Present Rates	Historic Year December 31, 2024
7	B1-2 (R)	Bill Analysis- Revenues Under Present Rates	Historic Year December 31, 2024
8	B2 (R)	Summary Of Sales, Customers And Revenue At Present Rates	Future Test Year December 31, 2025
9	B2-1 (R)	Billing Units, Rates And Revenue At Present Rates	Future Test Year December 31, 2025
10	B3 (R)	Number of Customers Served Whose Bills Will be Increased	Years Ended 12/31/2024, 12/31/2025 and 12/31/2026
11	B4 (R)	Summary Of Sales, Customers And Revenue At Present and Proposed Rates	Fully Projected Future Test Year December 31, 2026
12	B4-1 (R)	Billing Units, Rates And Revenue At PRESENT Rates	Fully Projected Future Test Year December 31, 2026
13	B4-2 (R)	Billing Units, Rates And Revenue At PROPOSED Rates	Fully Projected Future Test Year December 31, 2026
14			
15		**TARIFF RATES**	
16	B5 (R)	Summary Of Present And Proposed Tariff Rates	Historic Year December 31, 2024 and Fully Projected Future Test Year December 31, 2026
17	B5-1 (R)	Bill Comparisons (including GCR present rate)	Fully Projected Future Test Year December 31, 2026
18	B5-2 (R)	Bill Comparisons (excluding GCR)	Fully Projected Future Test Year December 31, 2026
19			
20		**NET OPERATING INCOME AND RATES OF RETURN**	
21	C1 (R)	Net Operating Income And Rates of Return	Years Ended 12/31/2024, 12/31/2025 and 12/31/2026
22	C1-1 (R)	Support Sheet No. 1- Operating Expense and Going-Level Adjustments	Years Ended 12/31/2024, 12/31/2025 and 12/31/2026
23	C1-2 (R)	Support Sheet No. 2- Summary of Cost of Capital and Fair Rate of Return Based upon a Hypothetical Ratemaking Capital Structure	12/31/2026
24	C1-3 (R)	Support Sheet No. 3- Taxes Other Than Income	Years Ended 12/31/2024, 12/31/2025 and 12/31/2026
25	C1-4 (R)	Support Sheet No. 4- Income Tax Calculations	Years Ended 12/31/2024, 12/31/2025 and 12/31/2026
26	C1-5 (R)	Support Sheet No. 5- Computation of Rate Base	Years Ended 12/31/2024, 12/31/2025 and 12/31/2026
27	C1-8 (R)	Comparison to Prior Rate Case	Prior Rate Case and Fully Projected Future Test Year December 31, 2026
28	C2 (R)	Balance Sheets	Years Ended 12/31/2024, 12/31/2025 and 12/31/2026
29	C3 (R)	Original Cost of Utility Plant in Service	Years Ended 12/31/2024, 12/31/2025 and 12/31/2026
30			
31		**WORKPAPERS**	
32	WP (R)	Workpapers	See separate index

B (R)

Valley Energy, Inc. (PA)
Rate Case with Fully Projected Future Test Year 2026 (R)

Operating Revenue Under Present Rates and Proposed Rates
Years Ended 12/31/2024, 12/31/2025 and 12/31/2026
Answer to 52 Pa. Code 53.52 b[4]

Line	Operating Revenues	Historic Year December 31, 2024		PRESENT RATES Future Test Year December 31, 2025	PRESENT RATES Fully Projected Future Test Year December 31, 2026	PROPOSED RATES Fully Projected Future Test Year December 31, 2026
		Per Books	Distribution Only	Distribution Only	Distribution Only	Distribution Only
1	Residential sales	$4,526,671	$2,823,518	$3,135,633	3,159,547	3,898,179
2	Commercial and Industrial sales	1,764,263	893,396	976,270	976,270	1,199,709
3	Transportation	2,217,436	2,217,436	2,321,925	2,347,099	2,670,984
4	Subtotal	8,508,370	5,934,349	6,433,828	6,482,916	7,768,872
5						
6	Forfeited Discounts	15,894	15,894	15,894	15,894	15,894
7	Other operating revenue	3,360	3,360	3,360	3,360	3,360
8	Non-operating revenue	1,950	1,950	4,321	4,321	4,321
9	Total Operating Revenues	$8,529,574	$5,955,553	$6,457,402	$6,506,491	$7,792,446

B1 (R)

Valley Energy, Inc. (PA)
Rate Case with Fully Projected Future Test Year 2026 (R)

Summary Of Sales, Customers And Revenue At Present Rates
Historic Year December 31, 2024

Line	Rate Class	Volumes (ccf)	Customers	Revenue - Present Rates		
				Fixed Customer Charge	Variable Distribution-Commodity	Distribution Total
1	Residential Sales Customers					
2	Rate R- Residential	5,020,399	6,486	$961,201	$1,862,317	2,823,518
3						
4	Commercial and Industrial Sales Customers					
5	Rate C- Commercial	2,258,909	854	224,988	630,891	855,878
6	Rate IS- Interruptible Service	251,560	1	984	21,815	22,799
7	Rate SI- Small Industrial	57,691	4	3,936	10,782	14,718
8		2,568,160	859	229,908	663,488	893,396
9						
10	Transportation Customers					
11	Transport. Firm	2,581,397	12	11,808	482,463	494,271
12	Transport. Firm- Fixed	8,382,960	1	497,874		497,874
13	Transport. Firm- Volumetric	6,355,340	1		320,553	320,553
14	Transport. Firm- DDQ	975,293	56	14,750	272,390	287,140
15	Rate I - Large Industrial					
16	Transport. Interruptible	7,065,009	5	4,920	612,678	617,598
17		25,359,999	75	529,352	1,688,083	2,217,436
18						
19	TOTAL	32,948,558	7,420	$1,720,460	$4,213,889	$5,934,349

B1-1 (R

Valley Energy, Inc. (PA)
Rate Case with Fully Projected Future Test Year 2026 (R)

Billing Units, Rates And Revenue At Present Rates
Historic Year December 31, 2024

Line	Description	Rate R- Residential	Rate C- Commercial	Rate IS- Interruptible Service	Rate SI- Small Industrial	Rate ST- Transport Firm	Rate I Large Industrial Firm	Transport Firm- Contract	Transport. Firm- DDQ	Transport. Interruptible	Total
1						**BILLING UNITS**					
2	ccf Sales	5,020,399	2,258,909	251,560	57,691	2,581,397		14,738,300	975,293	7,065,009	32,948,558
3											
4	Number of Bills	77,830	10,250	12	48	144		24	672	60	89,040
5	Average Monthly Bills	6,486	854	1	4	12		2	56	5	7,420
6											
7						**RATES AND CHARGES**					
8						**Tariff Rates**					
9	Customer Charge	$12.35	$21.95	$82.00	$82.00	$82.00		$0.00	$21.95	$82.00	
10								Contract-2			
11	Commodity Block 1	$0.37095	$0.279290	$0.086720	$0.186900	$0.186900		$0.0503	$0.279290	$0.086720	
12	Commodity Block 2							$0.0516			
13	Commodity Block 3										
14											
15	Demand Block 1										
16	Demand Block 2							Contract-1			
17	Fixed Monthly, Oct-Dec							$41,028	Thru 10/2024		
18	Fixed Monthly, Jan-Sep							$42,874	10/2024-09/2025		
19						**COMPUTATION OF REVENUE**					
20	Fixed Charge Revenue	961,201	224,988	984	3,936	11,808		497,874	14,750	4,920	1,720,460
21	Volumetric Revenue	1,862,317	630,891	21,815	10,782	482,463		320,553	272,390	612,678	4,213,889
22	**Total Distribution Revenue**	$2,823,518	$855,878	$22,799	$14,718	$494,271		$818,427	$287,140	$617,598	$5,934,349
23	*Check WP1_B*	*2,823,518*	*855,878*	*22,799*	*14,718*	*494,271*		*818,427*	*287,140*	*617,598*	*617,598*
24						**BILLING UNITS- DETAIL**					
25	ccf Sales	5,020,399	2,258,909	251,560	57,691	2,581,397	0	14,738,300	975,293	7,065,009	32,948,558
26											
27											

B1-2 (R)

Valley Energy, Inc. (PA)
Rate Case with Fully Projected Future Test Year 2026 (R)

Bill Analysis- Revenues Under Present Rates
Historic Year December 31, 2024

Line	Customer Type	Rate Case Amounts: Computed Delivery	Rate Case Amounts: Computed GCR	Rate Case Amounts: Other Revenue	Rate Case Amounts: Total for Rate Case	Unbilled, Reconciling Items and Other	Total Per Financials
1	Residential sales	$2,823,518	$1,703,154		$4,526,671		$4,526,671
2	Commercial and Industrial sales	893,396	870,867		1,764,263		1,764,263
3	Transportation	2,217,436			2,217,436		2,217,436
4	**Distribution Revenue**	5,934,349	2,574,021	0	8,508,370	0	8,508,370
5							
6	Forfeited Discounts			15,894	15,894		15,894
7	Other operating			3,360	3,360		3,360
8	Patronage Capital						
9	ISF Fees			1,950	1,950		1,950
10	**Total Revenue for Rate case**	**$5,934,349**	**$2,574,021**	**$21,204**	**$8,529,574**	**0**	**8,529,574**
11							
12	Prior Year E Factor Allocation					993,373	993,373
13	Over (Under) Gas					(174,685)	(174,685)
14	Residential Unbilled					104,925	104,925
15	Commercial Unbilled					34,975	34,975
16	Other Revenue					517,200	517,200
17	Rounding					(626)	(626)
18	**Total Operating Revenue per Financials**				**$8,529,574**	**$1,475,162**	**$10,004,736**
19						10,004,736	10,004,736

B2 (R)

Valley Energy, Inc. (PA)
Rate Case with Fully Projected Future Test Year 2026 (R)

Summary Of Sales, Customers And Revenue At Present Rates
Future Test Year December 31, 2025

Line	Rate Class	Volumes (ccf)	Customers	Revenue - Present Rates		
				Fixed Customer Charge	Variable Distribution-Commodity	Distribution Total
1	Residential Sales Customers					
2	Rate R- Residential	5,841,818	6,536	$968,611	$2,167,022	3,135,633
3						
4	Commercial and Industrial Sales Customers					
5	Rate C- Commercial	2,566,623	851	224,153	716,832	940,986
6	Rate IS- Interruptible Service	222,000	1	984	19,252	20,236
7	Rate SI- Small Industrial	59,459	4	3,936	11,113	15,049
8		2,848,082	856	229,073	747,197	976,270
9						
10	Transportation Customers					
11	Transport. Firm	1,881,944	11	10,824	351,735	362,559
12	Transport. Firm- Fixed	8,470,343	1	518,991		518,991
13	Transport. Firm- Volumetric	7,175,742	1		437,868	437,868
14	Transport. Firm- DDQ	947,972	56	14,750	264,759	279,509
15	Rate I - Large Industrial	3,581,019	1	0	360,079	360,079
16	Transport. Interruptible	4,139,559	4	3,936	358,983	362,919
17		26,196,578	74	548,501	1,773,423	2,321,925
18						
19	TOTAL	34,886,478	7,466	$1,746,185	$4,687,643	$6,433,828

B2-1 (R

Valley Energy, Inc. (PA)
Rate Case with Fully Projected Future Test Year 2026 (R)

Billing Units, Rates And Revenue At Present Rates
Future Test Year December 31, 2025

Line	Description	Rate R- Residential	Rate C- Commercial	Rate IS- Interruptible Service	Rate SI- Small Industrial	Rate ST- Transport Firm	Rate I Large Industrial Firm	Transport Firm- Contract	Transport. Firm- DDQ	Transport. Interruptible	Total
1		**BILLING UNITS**									
2	ccf Sales- annualized	5,841,818	2,566,623	222,000	59,459	1,881,944	3,581,019	15,646,085	947,972	4,139,559	34,886,478
3											
4	Number of Bills	78,430	10,212	12	48	132	12	24	672	48	89,590
5	Number of Customers	6,536	851	1	4	11	1	2	56	4	7,466
6											
7		**RATES AND CHARGES**									
8		**Tariff Rates**									
9	Customer Charge	$12.35	$21.95	$82.00	$82.00	$82.00	$0.00	$0.00	$21.95	$82.00	
10								Contract-2			
11	Commodity Block 1	$0.37095	$0.27929	$0.08672	$0.18690	$0.18690	$0.14158	$0.0516	$0.279290	$0.08672	
12	Commodity Block 2						$0.08696	$0.0526			
13	Commodity Block 3						$0.05697				
14											
15	Demand Block 1						$1.55432				
16	Demand Block 2						$0.80660	Contract-1			
17	Fixed Monthly, Oct-Dec							$42,874	10/2024-09/2025		
18	Fixed Monthly, Jan-Sep							$44,375	10/2025-09/2026		
19		**COMPUTATION OF REVENUE**									
20	Fixed Charge Revenue	968,611	224,153	984	3,936	10,824		518,991	14,750	3,936	1,746,185
21	Volumetric Revenue	2,167,022	716,832	19,252	11,113	351,735	360,079	437,868	264,759	358,983	4,687,643
22	**Total Distribution Revenue**	$3,135,633	$940,986	$20,236	$15,049	$362,559	$360,079	$956,859	$279,509	$362,919	$6,433,828
23											
24		**BILLING UNITS- DETAIL**									
25	ccf Sales	5,841,818	2,566,623	222,000	59,459	1,881,944	3,581,019	15,646,085	947,972	4,139,559	34,886,478
26	Customers	6,536	851	1	4	11	1	2	56	4	7,466
27											
28											

B3 (R)

Valley Energy, Inc. (PA)
Rate Case with Fully Projected Future Test Year 2026 (R)

Number of Customers Served Whose Bills Will be Increased
Years Ended 12/31/2024, 12/31/2025 and 12/31/2026
Answer to 52 Pa. Code 53.52 b[3]

Line	Customer Type	Average Number of Customers During the Year		
		12/31/2024	12/31/2025	12/31/2026
1	Residential sales	6,486	6,536	6,586
2	Commercial and Industrial sales	859	856	856
3	Transportation	73	72	72
4	Customers with rates changing	7,418	7,464	7,514
5	Rates not changing	2	2	2
6	Total Customers Served	7,420	7,466	7,516
7				
8				
9				

B4 (R)

Valley Energy, Inc. (PA)
Rate Case with Fully Projected Future Test Year 2026 (R)

Summary Of Sales, Customers And Revenue At Present and Proposed Rates
Fully Projected Future Test Year December 31, 2026

				Revenue - Present Rates			Revenue - Proposed Rates					
Line	Rate Class	Sales (ccf)	Customers	Fixed Charge	Volumetric	Distribution Total	Fixed Charge	Volumetric	Distribution Total	Target Revenue	Proposed Increase	Proposed Increase %
1	Residential Sales Customers											
2	Rate R- Residential	5,886,309	6,586	$976,021	$2,183,526	3,159,547	$1,106,420	$2,791,759	3,898,179	3,898,154	738,632	23.38%
3												
4	Commercial and Industrial Sales Customers											
5	Rate C- Commercial	2,566,623	851	224,153	716,832	940,986	255,300	900,936	1,156,236	1,160,960	215,250	22.88%
6	Rate IS- Interruptible Service	222,000	1	984	19,252	20,236	1,200	23,756	24,956	24,966	4,720	23.33%
7	Rate SI- Small Industrial	59,459	4	3,936	11,113	15,049	4,800	13,717	18,517	18,567	3,468	23.05%
8		2,848,082	856	229,073	747,197	976,270	261,300	938,409	1,199,709	1,204,493	223,439	22.89%
9												
10	Transportation Customers											
11	Transport. Firm	1,881,944	11	10,824	351,735	362,559	13,200	434,164	447,364	447,315	84,805	23.39%
12	Transport. Firm- Fixed	8,470,343	1	536,493		536,493	536,493		536,493	536,493	0	0.00%
13	Transport. Firm- Volumetric	7,175,742	1		445,540	445,540		445,540	445,540	445,540		0.00%
14	Transport. Firm- DDQ	947,972	56	14,750	264,759	279,509	16,800	332,757	349,557	344,850	70,048	25.06%
15	Rate I - Large Industrial	3,581,019	1	0	360,079	360,079	3,600	440,655	444,255	444,254	84,176	23.38%
16	Transport. Interruptible	4,139,559	4	3,936	358,983	362,919	4,800	442,974	447,774	447,758	84,856	23.38%
17		26,196,578	74	566,003	1,781,096	2,347,099	574,893	2,096,091	2,670,984	2,666,211	323,885	13.80%
18												
19	TOTAL	34,930,969	7,516	$1,771,097	$4,711,819	$6,482,916	$1,942,613	$5,826,259	$7,768,872	$7,768,858	$1,285,956	19.84%
20												
21	Overall Distribution Increase										19.84%	

B4-1 (R

Valley Energy, Inc. (PA)
Rate Case with Fully Projected Future Test Year 2026 (R)

Billing Units, Rates And Revenue At PRESENT Rates
Fully Projected Future Test Year December 31, 2026

Line	Description	Rate R- Residential	Rate C- Commercial	Rate IS- Interruptible Service	Rate SI- Small Industrial	Rate ST- Transport Firm	Rate I Large Industrial Firm	Transport Firm- Contract	Transport. Firm- DDQ	Transport. Interruptible	Total
1		**BILLING UNITS**									
2	ccf Sales	5,886,309	2,566,623	222,000	59,459	1,881,944	3,581,019	15,646,085	947,972	4,139,559	34,930,969
3											
4	Number of Bills	79,030	10,212	12	48	132	12	24	672	48	90,190
5	Average Monthly Bills	6,586	851	1	4	11	1	2	56	4	7,516
6											
7		**RATES AND CHARGES**									
8		**Tariff Rates**									
9	Customer Charge	$12.35	$21.95	$82.00	$82.00	$82.00		$0.00	$21.95	$82.00	
10								Contract-2			
11	Commodity Block 1	$0.370950	$0.279290	$0.086720	$0.186900	$0.186900	$0.141580	$0.0526	$0.279290	$0.086720	
12	Commodity Block 2						$0.086960	$0.0526			
13	Commodity Block 3						$0.056970				
14											
15	Demand Block 1						$1.554320				
16	Demand Block 2						$0.806600	Contract-1			
17	Fixed Monthly, Oct-Dec							$44,375	10/2025-09/2026		
18	Fixed Monthly, Jan-Sep							$45,706	10/2026-		
19		**COMPUTATION OF REVENUE**									
20	Fixed Charge Revenue	976,021	224,153	984	3,936	10,824		536,493	14,750	3,936	1,771,097
21	Volumetric Revenue	2,183,526	716,832	19,252	11,113	351,735	360,079	445,540	264,759	358,983	4,711,819
22	**Total Distribution Revenue**	$3,159,547	$940,986	$20,236	$15,049	$362,559	$360,079	$982,033	$279,509	$362,919	$6,482,916
23											
24		**BILLING UNITS- DETAIL**									
25	ccf Sales	5,886,309	2,566,623	222,000	59,459	1,881,944	3,581,019	15,646,085	947,972	4,139,559	34,930,969
26	Customers	6,586	851	1	4	11	1	2	56	4	7,516
27											

Valley Energy, Inc. (PA)
Rate Case with Fully Projected Future Test Year 2026 (R)

Billing Units, Rates And Revenue At PROPOSED Rates
Fully Projected Future Test Year December 31, 2026

Line	Description	Rate R- Residential	Rate C- Commercial	Rate IS- Interruptible Service	Rate SI- Small Industrial	Rate ST- Transport Firm	Rate I Large Industrial Firm	Transport Firm- Contract	Transport. Firm- DDQ	Transport. Interruptible	Total
1						**BILLING UNITS**					
2	ccf Sales	5,886,309	2,566,623	222,000	59,459	1,881,944	3,581,019	15,646,085	947,972	4,139,559	34,930,969
3											
4	Number of Bills	79,030	10,212	12	48	132	12	24	672	48	90,190
5	Average Monthly Bills	6,586	851	1	4	11	1	2	56	4	7,516
6											
7						**RATES AND CHARGES**					
8						**Tariff Rates**					
9	Customer Charge	$14.00	$25.00	$100.00	$100.00	$100.00	$300.00	$0.00	$25.00	$100.00	
10								Contract-2			
11	Commodity Block 1	$0.47428	$0.35102	$0.10701	$0.23070	$0.23070	$0.17468	$0.0526	$0.35102	$0.10701	
12	Commodity Block 2						$0.09263	$0.0526			
13	Commodity Block 3										
14											
15	Demand Block 1						$1.91767				
16	Demand Block 2						$0.99516	Contract-1			
17	Fixed Monthly, Oct-Dec							44,375	Thru Sep		
18	Fixed Monthly, Jan-Sep							45,706	Oct-Dec		
19						**COMPUTATION OF REVENUE**					
20	Fixed Charge Revenue	1,106,420	255,300	1,200	4,800	13,200	3,600	536,493	16,800	4,800	1,942,613
21	Volumetric Revenue	2,791,759	900,936	23,756	13,717	434,164	440,655	445,540	332,757	442,974	5,826,259
22	**Total Distribution Revenue**	$3,898,179	$1,156,236	$24,956	$18,517	$447,364	$444,255	$982,033	$349,557	$447,774	**$7,768,872**
23	Target	3,898,154	1,160,960	24,966	18,567	447,315	444,254	982,033	344,850	447,758	7,768,858
24						**BILLING UNITS- DETAIL**					
25	Block 1 ccf Sales	5,886,309	2,566,623	222,000	59,459	1,881,944	3,581,019	15,646,085	947,972	4,139,559	34,930,969
26										*Check*	*34,930,969*

Valley Energy, Inc. (PA)
Rate Case with Fully Projected Future Test Year 2026 (R)

Summary Of Present And Proposed Tariff Rates
Historic Year December 31, 2024 and Fully Projected Future Test Year December 31, 2026

Line		Present Rates (excluding GCR)	GCR Current	Present Rates (including GCR prsesent rate)	Proposed Rates (excluding GCR)	GCR Current	Proposed Rates (including GCR present rate)	Proposed Increase (excluding GCR)	Proposed Increase (including GCR present rate)
1	**Rate R- Residential**								
2	Customer Charge per Bill	$12.35		$12.35	$14.00		$14.00	13.36%	13.36%
3									
4	Commodity charge per ccf								
5	All usage	$0.37095	$0.34569	$0.71664	$0.47428	$0.34569	$0.81997	27.86%	14.42%
6	**Rate C- Commercial**								
7	Customer Charge per Bill	$21.95		$21.95	$25.00		$25.00	13.90%	13.90%
8									
9	Commodity charge per ccf								
10	All usage	$0.27929	$0.34569	$0.62498	$0.35102	$0.34569	$0.69671	25.68%	11.48%
11	**Rate I- Large Industrial Firm**								
12	Customer Charge per Bill			$0.00	$300.00		$300.00		
13									
14	Commodity charge per ccf								
15	Block 1	$0.14158	$0.34569	$0.48727	$0.17468	$0.34569	$0.52037	23.38%	6.79%
16	Block 2	$0.08696	$0.34569	$0.43265	$0.09263	$0.34569	$0.43832	6.52%	1.31%
17	Block 3	$0.05697	$0.34569	$0.40266					
18									
19	Demand charge per mcf								
20	Block 1	$1.554320		$1.55432	$1.91767		$1.91767	23.38%	23.38%
21	Block 2	$0.806600		$0.80660	$0.99516		$0.99516	23.38%	23.38%
22	**Rate IS- Interruptible Service**								
23	Customer Charge per Bill	$82.00		$82.00	$100.00		$100.00	21.95%	21.95%
24									
25	Transport charge per ccf								
26	All usage	$0.08672		$0.0867	$0.10701		$0.1070	23.40%	23.40%

Valley Energy, Inc. (PA)
Rate Case with Fully Projected Future Test Year 2026 (R)

Summary Of Present And Proposed Tariff Rates
Historic Year December 31, 2024 and Fully Projected Future Test Year December 31, 2026

Line		Present Rates (excluding GCR)	GCR Current	Present Rates (including GCR prsesent rate)	Proposed Rates (excluding GCR)	GCR Current	Proposed Rates (including GCR present rate)	Proposed Increase (excluding GCR)	Proposed Increase (including GCR present rate)
27	**Rate SI- Small Industrial**								
28	Customer Charge per Bill	$82.00		$82.00	$100.00		$100.00	21.95%	21.95%
29									
30	Demand charge per mcf								
31	All usage	$0.1869	$0.3457	$0.5326	$0.2307	$0.3457	$0.5764	23.43%	8.22%
32	**Rate ST- Transport Firm**								
33	Customer Charge per Bill	$82.00		$82.00	$100.00		$100.00	21.95%	
34									
35	Transport charge per ccf								
36	All usage	$0.1869		$0.1869	$0.2307		$0.2307	23.43%	23.43%
37	**Transport. Firm- DDQ**								
38	Customer Charge per Bill	$21.95		$21.95	$25.00		$25.00	13.90%	13.90%
39									
40	Transport charge per ccf								
41	All usage	$0.2793		$0.2793	$0.3510		$0.3510	25.68%	25.68%
42	**Transport. Interruptible**								
43	Customer Charge per Bill	$82.00		$82.00	$100.00		$100.00	21.95%	
44									
45	Transport charge per ccf								
46	All usage	$0.0867		$0.0867	$0.1070		$0.1070	23.40%	23.40%

B5-1 (F

Valley Energy, Inc. (PA)
Rate Case with Fully Projected Future Test Year 2026 (R)

Bill Comparisons (including GCR present rate)
Fully Projected Future Test Year December 31, 2026
Rate R- Residential

Line	Average	Sales (ccf)	Present Rates		Proposed Rates		Increase	
			Monthly Bill	Cost per ccf	Monthly Bill	Cost per ccf	$ per Monthly	%
1		Minimum	$12.35		$14.00		$1.65	13.36%
2		10	19.52	$1.95164	22.20	$2.21997	2.68	13.75%
3		20	26.68	1.33414	30.40	1.51997	3.72	13.93%
4	All Residential, Apr-Sep	36	38.15	1.05970	43.52	1.20886	5.37	14.08%
5		50	48.18	0.96364	55.00	1.09997	6.82	14.15%
6	All Residential, Annual	76	66.81	0.87914	76.32	1.00418	9.50	14.22%
7	All Residential, Oct-Mar	117	96.20	0.82220	109.94	0.93963	13.74	14.28%
8		150	119.85	0.79897	137.00	0.91330	17.15	14.31%
9		200	155.68	0.77839	177.99	0.88997	22.32	14.33%
10		250	191.51	0.76604	218.99	0.87597	27.48	14.35%
11								

Rate C- Commercial

Line	Average	Sales (ccf)	Present Rates		Proposed Rates		Increase	
			Monthly Bill	Cost per ccf	Monthly Bill	Cost per ccf	$ per Monthly	%
16		Minimum	$21.95		$25.00		$3.05	13.90%
17		25	37.57	$1.50298	42.42	$1.69671	4.84	12.89%
18		50	53.20	1.06398	59.84	1.19671	6.64	12.47%
19		100	84.45	0.84448	94.67	0.94671	10.22	12.11%
20		200	146.95	0.73473	164.34	0.82171	17.40	11.84%
21	All Commercial, Annual	258	183.19	0.71006	204.75	0.79361	21.56	11.77%
22		300	209.44	0.69815	234.01	0.78004	24.57	11.73%
23		400	271.94	0.67986	303.68	0.75921	31.74	11.67%
24		500	334.44	0.66888	373.36	0.74671	38.91	11.64%
25		750	490.69	0.65425	547.53	0.73004	56.85	11.59%
26		1,000	646.93	0.64693	721.71	0.72171	74.78	11.56%
27								

B5-1 (F

Valley Energy, Inc. (PA)
Rate Case with Fully Projected Future Test Year 2026 (R)

Bill Comparisons (including GCR present rate)
Fully Projected Future Test Year December 31, 2026
Rate SI- Small Industrial

Average	Sales (ccf)	Present Rates		Proposed Rates		Increase	
		Monthly Bill	Cost per ccf	Monthly Bill	Cost per ccf	$ per Monthly	%
	Minimum	$82.00		$100.00		$18.00	21.95%
	2,000	1,147.18	$0.57359	1,252.78	$0.62639	105.60	9.21%
	4,000	2,212.36	0.55309	2,405.56	0.60139	193.20	8.73%
	6,000	3,277.54	0.54626	3,558.34	0.59306	280.80	8.57%
	8,000	4,342.72	0.54284	4,711.12	0.58889	368.40	8.48%
	10,000	5,407.90	0.54079	5,863.90	0.58639	456.00	8.43%
	12,000	6,473.08	0.53942	7,016.68	0.58472	543.60	8.40%
	14,000	7,538.26	0.53845	8,169.46	0.58353	631.20	8.37%
	16,000	8,603.44	0.53772	9,322.24	0.58264	718.80	8.35%
	18,000	9,668.62	0.53715	10,475.02	0.58195	806.40	8.34%
	20,000	10,733.80	0.53669	11,627.80	0.58139	894.00	8.33%

B5-2 (R

Valley Energy, Inc. (PA)
Rate Case with Fully Projected Future Test Year 2026 (R)

Bill Comparisons (excluding GCR)
Fully Projected Future Test Year December 31, 2026
Rate R- Residential

Line	Average	Sales (ccf)	Present Rates		Proposed Rates		Increase	
			Monthly Bill	Cost per ccf	Monthly Bill	Cost per ccf	$ per Monthly	%
1		Minimum	$12.35		$14.00		$1.65	13.36%
2		10	16.06	$1.60595	18.74	$1.87428	2.68	16.71%
3		20	19.77	0.98845	23.49	1.17428	3.72	18.80%
4	All Residential, Apr-Sep	36	25.70	0.71401	31.07	0.86317	5.37	20.89%
5		50	30.90	0.61795	37.71	0.75428	6.82	22.06%
6	All Residential, Annual	76	40.54	0.53345	50.05	0.65849	9.50	23.44%
7	All Residential, Oct-Mar	117	55.75	0.47651	69.49	0.59394	13.74	24.64%
8		150	67.99	0.45328	85.14	0.56761	17.15	25.22%
9		200	86.54	0.43270	108.86	0.54428	22.32	25.79%
10		250	105.09	0.42035	132.57	0.53028	27.48	26.15%
11								

Rate C- Commercial

14			Present Rates		Proposed Rates		Increase	
15	Average	Sales (ccf)	Monthly Bill	Cost per ccf	Monthly Bill	Cost per ccf	$ per Monthly	%
16		Minimum	$21.95		$25.00		$3.05	13.90%
17		25	28.93	$1.15729	33.78	$1.35102	4.84	16.74%
18		50	35.91	0.71829	42.55	0.85102	6.64	18.48%
19		100	49.88	0.49879	60.10	0.60102	10.22	20.50%
20		200	77.81	0.38904	95.20	0.47602	17.40	22.36%
21	All Commercial, Annual	258	94.01	0.36437	115.56	0.44792	21.56	22.93%
22		300	105.74	0.35246	130.31	0.43435	24.57	23.24%
23		400	133.67	0.33417	165.41	0.41352	31.74	23.75%
24		500	161.60	0.32319	200.51	0.40102	38.92	24.08%
25		750	231.42	0.30856	288.27	0.38435	56.85	24.56%
26		1,000	301.24	0.30124	376.02	0.37602	74.78	24.82%
27								

B5-2 (R

Valley Energy, Inc. (PA)
Rate Case with Fully Projected Future Test Year 2026 (R)

Bill Comparisons (excluding GCR)
Fully Projected Future Test Year December 31, 2026
Rate SI- Small Industrial

			Present Rates		Proposed Rates		Increase	
Average	Sales (ccf)	Monthly Bill	Cost per ccf	Monthly Bill	Cost per ccf	$ per Monthly	%
	Minimum	$82.00		$100.00		$18.00	21.95%
	2,000	455.80	$0.22790	561.40	$0.28070	105.60	23.17%
	4,000	829.60	0.20740	1,022.80	0.25570	193.20	23.29%
	6,000	1,203.40	0.20057	1,484.20	0.24737	280.80	23.33%
	8,000	1,577.20	0.19715	1,945.60	0.24320	368.40	23.36%
	10,000	1,951.00	0.19510	2,407.00	0.24070	456.00	23.37%
	12,000	2,324.80	0.19373	2,868.40	0.23903	543.60	23.38%
	14,000	2,698.60	0.19276	3,329.80	0.23784	631.20	23.39%
	16,000	3,072.40	0.19203	3,791.20	0.23695	718.80	23.40%
	18,000	3,446.20	0.19146	4,252.60	0.23626	806.40	23.40%
	20,000	3,820.00	0.19100	4,714.00	0.23570	894.00	23.40%

Valley Energy, Inc. (PA)
Rate Case with Fully Projected Future Test Year 2026 (R)
Net Operating Income And Rates of Return
Years Ended 12/31/2024, 12/31/2025 and 12/31/2026
Answer to 52 Pa. Code 53.52 c[1]

Line	Description	Historic Year December 31, 2024		Future Test Year December 31, 2025	Present Rates Fully Projected Future Test Year December 31, 2026	Revenue Requirement Fully Projected Future Test Year December 31, 2026	Proposed Rates Fully Projected Future Test Year December 31, 2026
		Per Books	Distribution Only	Distribution Only	Distribution Only	Distribution Only	Distribution Only
1	REVENUE						
2	Residential	$4,526,671	$2,823,518	$3,135,633	$3,159,547		3,898,179
3	Commercial and industrial	1,764,263	893,396	976,270	976,270		1,199,709
4	Transportation	2,217,436	2,217,436	2,321,925	2,347,099		2,670,984
5	Operating revenue	8,508,370	5,934,349	6,433,828	6,482,916	7,768,858	7,768,872
6	Other revenue, net	21,204	21,204	23,575	23,575	23,575	23,575
7	Total Revenue	8,529,574	5,955,553	6,457,402	6,506,491	7,792,433	7,792,446
8	*ccf*	*32,948,558*		*34,886,478*	*34,930,969*	*34,930,969*	*34,930,969*
9	EXPENSES				Increase	1,285,942	
10	Purchased gas (in revenue)	3,650,808					
11	Distribution	1,885,489	1,885,489	1,725,247	1,939,388	1,939,388	1,939,388
12	Customer accounting & collection	649,422	649,422	742,899	769,686	781,463	781,463
13	Rate case expense normalization				92,222	92,222	92,222
14	Administrative & general expenses	1,117,167	1,117,167	1,187,491	1,178,523	1,178,523	1,178,523
15	Total Operating expenses	7,302,887	3,652,079	3,655,637	3,979,819	3,991,596	3,991,596
16							
17	Depreciation expense	1,307,234	1,307,234	1,425,492	1,380,407	1,380,407	1,380,407
18	Taxes other than income	29,354	29,354	31,385	33,587	33,587	33,587
19							
20	Total Expenses	8,639,475	4,988,667	5,112,514	5,393,813	5,405,590	5,405,590
21							
22	Oper Inc (Loss) before Income Tax	(109,901)	966,887	1,344,888	1,112,678	2,386,842	2,386,856
23							
24	Income tax expense	(335,733)	23,014	88,125	(51,503)	291,466	291,469
25	NET UTILITY OPERATING INCOME (LOSS) (A)	$225,833	$943,872	$1,256,764	$1,164,180	$2,095,377	$2,095,387
26							
27	RATE BASE (B)	$21,798,061	$21,798,061	$23,552,662	$25,337,084	$25,337,084	$25,337,084
28	RATE OF RETURN ON RATE BASE (	1.04%	4.33%	5.34%	4.59%	8.27%	8.27%
29							

Valley Energy, Inc. (PA)
Rate Case with Fully Projected Future Test Year 2026 (R)
Net Operating Income And Rates of Return
Years Ended 12/31/2024, 12/31/2025 and 12/31/2026
Answer to 52 Pa. Code 53.52 c[1] - Support Sheet No. 1
Support Sheet No. 1- Operating Expense and Going-Level Adjustments

Line	Acct	Account Description	Historic Year December 31, 2024	Adjust HTY to FTY	Future Test Year December 31, 2025	Adjust FTY to FPFTY	Fully Projected Future Test Year December 31, 2026	LABOR Historic Year December 31, 2024	LABOR Future Test Year December 31, 2025	LABOR Fully Projected Future Test Year December 31, 2026	LABOR Year 2023	LABOR Year 2022
1		Distribution Expenses										
2	842	Fuel	21,175	(45)	21,130	(783)	20,347	0	0	0	0	0
3	870	Labor Supv /Eng.	212,953	26,077	239,030	21,517	260,547	91,173	103,788	113,359	85,925	73,206
4	871	Distrib Load Disp	6,180	583	6,763	338	7,101	0	0	0	0	0
5	874	Mains & Services	454,825	(4,337)	450,488	129,994	580,482	130,294	136,278	193,236	127,283	127,504
6	875	Meas & Reg- Gen	102,219	(3,931)	98,288	8,432	106,720	37,665	35,758	40,056	35,110	33,429
7	876	Ind / Com Meters, Reg	102,463	(19,945)	82,517	11,884	94,402	39,962	31,539	36,372	36,611	37,240
8	877	Meas & Reg- City gate	34,460	(4,213)	30,247	1,882	32,129	8,437	6,288	7,065	7,655	5,698
9	878	Meters & House Reg	165,846	(21,594)	144,252	15,370	159,622	67,681	60,218	67,498	53,530	53,391
10	879	Cust installations	197,343	(24,159)	173,184	16,860	190,044	82,768	72,453	80,239	74,307	68,901
11	880	Other operating exp	114,706	(60,271)	54,435	16,249	70,684	41,265	20,603	27,982	0	0
12	881	Rents	5,803	419	6,222	447	6,669	0	0	0	0	0
13		*Total Operation*	1,417,971	(111,416)	1,306,556	222,190	1,528,746	499,245	466,925	565,807	420,421	399,370
14												
15	885	Super and eng	35,008	2,730	37,738	1,884	39,622	14,259	15,514	16,318	12,502	13,219
16	886	Structures & improve	38,923	(12,458)	26,465	(6,247)	20,218	7,393	7,488	6,038	8,899	8,948
17	887	Mains	107,656	10,252	117,909	15,556	133,465	31,237	36,769	43,282	33,978	30,618
18	889	Meas & Reg- Gen	76,337	(10,683)	65,654	(13,051)	52,603	25,905	20,343	18,035	22,348	16,121
19	890	Meas & Reg- Ind	23,623	(60)	23,563	2,726	26,289	8,834	8,837	10,141	10,483	12,196
20	891	Meas & Reg- City gate	6,926	963	7,889	4,902	12,791	1,736	1,715	1,979	1,992	3,070
21	892	Services	54,019	4,578	58,597	12,684	71,281	19,182	20,480	26,012	5,486	11,406
22	893	Meters & House Reg	125,026	(44,149)	80,876	(26,505)	54,372	44,570	29,166	23,748	31,880	42,810
23		*Total Maintenance*	467,518	(48,827)	418,691	(8,050)	410,641	153,117	140,312	145,553	127,568	138,387
24		*Total Distribution*	1,885,489	(160,242)	1,725,247	214,141	1,939,388	652,362	607,237	711,360	547,990	537,757

Valley Energy, Inc. (PA)
Rate Case with Fully Projected Future Test Year 2026 (R)
Net Operating Income And Rates of Return
Years Ended 12/31/2024, 12/31/2025 and 12/31/2026
Answer to 52 Pa. Code 53.52 c[1] - Support Sheet No. 1
Support Sheet No. 1- Operating Expense and Going-Level Adjustments

Line	Acct	Account Description	Historic Year December 31, 2024	Adjust HTY to FTY	Future Test Year December 31, 2025	Adjust FTY to FPFTY	Fully Projected Future Test Year December 31, 2026	LABOR Historic Year December 31, 2024	LABOR Future Test Year December 31, 2025	LABOR Fully Projected Future Test Year December 31, 2026	LABOR Year 2023	LABOR Year 2022
25												
26		Customer Accounting & Collection Expenses:										
27	902	Meter Reading Exp	25,595	2,510	28,106	(11,118)	16,988	8,187	9,734	6,193	7,419	8,690
28	903	Cust Rec & Coll Exp	610,473	17,502	627,975	33,628	661,603	194,876	214,654	229,723	197,534	186,407
29	904	Uncollect Acct (Dist)	(20,260)	70,755	50,495	3,853	54,348	0	0	0	0	0
30	905	Miscellaneous cust	19,214	2,278	21,492	0	21,492	0	0	0	0	0
31	909	Info & Inst Advert	12,402	372	12,774	383	13,157	0	0	0	0	0
32	913	Advertising	1,998	59	2,057	41	2,098	0	0	0	0	0
33		*Total Cust Acct & Coll*	649,422	93,477	742,899	26,787	769,686	203,063	224,388	235,916	204,954	195,097
34												
35		Administrative & General Expenses:										
36	920	A&G Salaries	653,724	(20,934)	632,791	48,766	681,556	278,745	276,347	298,043	276,347	276,347
37	921	Office Supp & Exp	56,476	22,894	79,370	2,020	81,390	0	0	0	0	0
38	923	Outside Services	84,557	(7,218)	77,339	4,669	82,008	0	0	0	0	0
39	924	Property Insurance	23,202	13,055	36,257	2,562	38,819	0	0	0	0	0
40	925	Injuries and damage	93,900	14,757	108,657	(14,757)	93,900	0	0	0	0	0
41	926	Empl Pens & Bene	6,502	3,396	9,898	296	10,194	0	0	0	0	0
42	928	Reg Comm Exp	89,218	10,296	99,514	(52,195)	47,319	0	0	0	0	0
43	930	General advertising	72,246	30,615	102,861	1,237	104,098	0	0	0	0	0
44	930CV	COVID-related	0	0	0	0	0	0	0	0	0	0
45	932	Maint Gen plant	37,342	3,463	40,805	(1,565)	39,240	6,764	8,168	8,203	8,168	8,168
46		*Total A&G*	1,117,167	70,324	1,187,491	(8,968)	1,178,523	285,509	284,515	306,246	284,515	284,515
47												
48		**Total Oper & Maint**	**3,652,079**	**3,558**	**3,655,637**	**231,960**	**3,887,597**	**1,140,934**	**1,116,140**	**1,253,522**	**1,037,458**	**1,017,369**
49												
50		Labor	1,140,934	(24,794)	1,116,140	137,382	1,253,522					
51		Transportation	122,958	311	123,269	3,698	126,967					
52		Material	315,608	(37,959)	277,649	12,228	289,877					
53		OH	1,451,655	(88,097)	1,363,558	128,036	1,491,594					
54		Other	620,924	154,097	775,021	(49,384)	725,637					
55			3,652,079	3,558	3,655,637	231,960	3,887,597					

C1-2 (R)

Valley Energy, Inc. (PA)
Rate Case with Fully Projected Future Test Year 2026 (R)

Support Sheet No. 2- Summary of Cost of Capital and Fair Rate of Return Based upon a Hypothetical Ratemaking Capital Structure
12/31/2026

Line	Type of Capital	Ratios (1)	Cost Rate	Weighted Cost Rate
1	Long-Term Debt	51.06%	5.03%	2.57%
2	Common Equity	48.94%	11.65%	5.70%
3	Total	100.00%		8.27%
4	TargetROR			8.27%
5				
6	[1] Recommended hypothetical capital structure ratios as discussed in direct testimony.			

C1-3 (R)

Valley Energy, Inc. (PA)
Rate Case with Fully Projected Future Test Year 2026 (R)
Net Operating Income And Rates of Return
Years Ended 12/31/2024, 12/31/2025 and 12/31/2026
Answer to 52 Pa. Code 53.52 c[1]
Support Sheet No. 3- Taxes Other Than Income

Line	Description	Historic Year December 31, 2024		Future Test Year December 31, 2025	PRESENT RATES Fully Projected Future Test Year December 31, 2026	PROPOSED RATES Fully Projected Future Test Year December 31, 2026
		Per Books	Distribution Only	Distribution Onl	Distribution Only	Distribution Only
1	Taxes other than income:					
2	Pennsylvania Use Tax	478	478	478	478	478
3	Public Utility Realty Tax	28,876	28,876	30,907	33,109	33,109
4						
5		$29,354	$29,354	$31,385	$33,587	$33,587
6						
7	Plant assets		43,575,245	46,639,469	49,963,792	49,963,792
8	Tax rate		0.06627%			

Valley Energy, Inc. (PA)
Rate Case with Fully Projected Future Test Year 2026 (R)
Net Operating Income And Rates of Return
Years Ended 12/31/2024, 12/31/2025 and 12/31/2026
Answer to 52 Pa. Code 53.52 c[1]
Support Sheet No. 4- Income Tax Calculations

Line	Ddescription		Historic Year December 31, 2024		Future Test Year December 31, 2025	PRESENT RATES Fully Projected Future Test Year December 31, 2026	FULL REVENUE REQUIREMENT Fully Projected Future Test Year December 31, 2026	PROPOSED RATES Fully Projected Future Test Year December 31, 2026
			Per Books	Distribution Only	Distribution Only	Distribution Only	Distribution Only	Distribution Only
1	Net Operating Income Excluding Income Taxes		($109,901)	$966,887	$1,344,888	$1,112,678	$2,386,842	$2,386,856
2								
3	Non-Operating Expenses:							
4	Synchronized interest expense:							
5	Rate base		21,798,061	21,798,061	23,552,662	25,337,084	25,337,084	25,337,084
6								
7	Rate base for interest compuation		21,798,061	21,798,061	23,552,662	25,337,084	25,337,084	25,337,084
8	Weighted Cost of debt		2.570%	2.570%	2.570%	2.570%	2.570%	2.570%
9	Synchronized interest expense		560,210	560,210	605,303	651,163	651,163	651,163
10	Taxable income before depreciation tax adjustments		(670,111)	406,676	739,585	461,514	1,735,679	1,735,693
11								
12	Pennsylvania depreciation adjustment:							
13	Tax depreciation (using DDB method)		(2,115,013)	(2,115,013)	(2,528,871)	(2,227,569)	(2,227,569)	(2,227,569)
14	Book depreciation		1,307,234	1,307,234	1,425,492	1,380,407	1,380,407	1,380,407
15	Pennsylvania depreciation adjustment		(807,779)	(807,779)	(1,103,379)	(847,162)	(847,162)	(847,162)
16	Pennsylvania taxable income		(1,477,890)	499,455	322,114	(385,648)	888,517	888,531
17	Regulatory Pennsylvania income tax expense	9.99%	(125,473)	42,404	25,737	(28,885)	66,550	66,551
18								
19	Federal depreciation adjustment:	8.99%	8.49%	8.49%	7.99%	7.49%	7.49%	7.49%
20	Tax depreciation (using SL method)		(1,763,836)	(1,763,836)	(1,842,256)	(1,978,510)	(1,978,510)	(1,978,510)
21	Book depreciation		1,307,234	1,307,234	1,425,492	1,380,407	1,380,407	1,380,407
22	Federal depreciation adjustment		(456,603)	(456,603)	(416,763)	(598,103)	(598,103)	(598,103)
23								
24	Taxable income before depreciation tax adjustments		(670,111)	406,676	739,585	461,514	1,735,679	1,735,693
25	Federal depreciation adjustment		(456,603)	(456,603)	(416,763)	(598,103)	(598,103)	(598,103)
26	Pennsylvania income tax expense		125,473	(42,404)	(25,737)	28,885	(66,550)	(66,551)
27	Federal taxable income		(1,001,241)	(92,330)	297,085	(107,703)	1,071,027	1,071,039
28	Regulatory Federal income tax expense	21.00%	(210,261)	(19,389)	62,388	(22,618)	224,916	224,918
29	Regulatory Total income tax expense		($335,733)	$23,014	$88,125	($51,503)	$291,466	$291,469
30								
31	Deferred Federal Income Tax expense (included in above):							
32	Tax depreciation (using SL method)		1,763,836	1,763,836	1,842,256	1,978,510	1,978,510	1,978,510
33	Tax depreciation (using DDB method)		2,115,013	2,115,013	2,528,871	2,227,569	2,227,569	2,227,569
34			351,176	351,176	686,615	249,059	249,059	249,059
35	Federal tax rate		21.00%	21.00%	21.00%	21.00%	21.00%	21.00%
36	Deferred Federal income tax (credit)		$73,747	$73,747	$144,189	$52,302	$52,302	$52,302
37	Combined statutory tax rate	28.89%	27.71%	27.71%	27.31%	26.92%	26.92%	26.92%

C1-5 (R)

Valley Energy, Inc. (PA)
Rate Case with Fully Projected Future Test Year 2026 (R)
Net Operating Income And Rates of Return
Years Ended 12/31/2024, 12/31/2025 and 12/31/2026
Answer to 52 Pa. Code 53.52 c[1]
Support Sheet No. 5- Computation of Rate Base

Line	Description	Source	Historic Year December 31, 2024	Future Test Year December 31, 2025	Fully Projected Future Test Year December 31, 2026
1	Utility Plant in Service				
2	Assets	Schedule C3	$ 43,575,245	$ 46,639,469	$ 49,963,792
3	Less: Accumulated Depreciation	Schedule C3	(20,753,495)	(22,356,239)	(23,899,567)
4			22,821,750	24,283,230	26,064,224
5					
6	Less: Accumulated deferred income taxes	Line 31	(484,177)	(459,323)	(438,298)
7	Less: Customer deposits	Schedule C2	(394,763)	(394,763)	(394,763)
8	Natural gas inventories- avg balance for year	Workpaper 5 to Sch C	1,198,570	1,198,570	1,198,570
9	Unbundled, to be Recovered in GCR	To Schedule C4	(1,198,570)	(1,198,570)	(1,198,570)
10	Accrued OPEB Liability / OPEB Asset, net	Line 38	(848,035)	(571,368)	(617,479)
11	Materials & Supplies	Schedule C2	244,244	244,244	244,244
12			21,339,019	23,102,019	24,857,928
13	Cash Working Capital Allowance	Line 24	459,042	450,643	479,156
14	RATE BASE		$ 21,798,061	$ 23,552,662	$ 25,337,084
15					

C1-5 (R)

Valley Energy, Inc. (PA)
Rate Case with Fully Projected Future Test Year 2026 (R)
Net Operating Income And Rates of Return
Years Ended 12/31/2024, 12/31/2025 and 12/31/2026
Answer to 52 Pa. Code 53.52 c[1]
Support Sheet No. 5- Computation of Rate Base

Line	Description	Source	Historic Year December 31, 2024	Future Test Year December 31, 2025	Fully Projected Future Test Year December 31, 2026
16	Cash Working Capital Allowance:				
17	Operating Expenses	Schedule C1	$ 8,639,475	$ 5,112,514	$ 5,393,813
18	Deductions:				
19	Purchased Gas	Schedule C1	3,650,808	0	Increase
20	Depreciation Expense, Uncollectible, TOTI	Schedule C1	1,316,328	1,507,372	1,560,565
21	Total Deductions		4,967,136	1,507,372	1,560,565
22	Cash Operating Expenses		3,672,339	3,605,142	3,833,249
23	Cash Operating Expenses Ratio		1/8	1/8	1/8
24	Cash Working Capital Allowance		$ 459,042	$ 450,643	$ 479,156
25					
26	Regulatory Accumluated deferred income tax:				
27	Accumulated depreciation based on tax expense borne by ratepayers		37,481,985	39,313,415	41,266,769
28	Accumulated depreciation based on taxes paid by company		39,787,591	41,500,668	43,353,900
29	(Excess) depreciation taken by company		(2,305,606)	(2,187,253)	(2,087,132)
30	Federal tax rate		21.00%	21.00%	21.00%
31	Regulatory Accumluated deferred income tax (liability)		$ (484,177)	$ (459,323)	$ (438,298)
32					
33	Accrued OPEB Liability / OPEB Asset, net				
34	Accrued postretirement cost (Liability)		(816,705)	(816,705)	(816,705)
35	Regulatory (Liability)		(375,898)	(375,898)	(375,898)
36	Regulatory Assets			276,667	230,556
37	Deferred tax asset related to Regulatory Liabilities		344,568	344,568	344,568
38			(848,035)	(571,368)	(617,479)
39					

C1-6 (R)

Valley Energy, Inc. (PA)
Rate Case with Fully Projected Future Test Year 2026 (R)

Comparison to Prior Rate Case
Prior Rate Case and Fully Projected Future Test Year December 31, 2026

Line	Description	R-2022-3032300, Order	Fully Projected Future Test Year December 31, 2026	Difference-Needs Higher (Lower) Revenue
1	Revenue	6,478,861	6,506,491	(27,629)
2	*ccf*	*35,049,281*	*34,930,969*	
3				
4				
5	O&M	3,624,172	3,887,597	263,425
6	Taxes other than income, Rate Case	34,169	125,810	91,641
7	Depreciation	1,178,428	1,380,407	201,979
8	Income tax	254,071	291,466	37,394
9				
10	Rate Base	$19,756,771	$25,337,084	
11	Required Return	7.03%	8.27%	
12	Target Return	1,388,012	2,095,377	707,365
13				1,274,174
14	Uncollectibles		0.924%	11,777
15				
16	Rounding			(9)
17	Revenue Increase Required at Recommended Return			1,285,942
18	Per Schedule C1			1,285,942
19				

C2 (R)

Valley Energy, Inc. (PA)
Rate Case with Fully Projected Future Test Year 2026 (R)

Balance Sheets
Years Ended 12/31/2024, 12/31/2025 and 12/31/2026
Answer to 52 Pa. Code 53.52 c[2]

Line	Account Title	Per Books 12/31/2024	Pro Forma 12/31/2025	Pro Forma 12/31/2026
1	**Assets and Other Debits**			
2	Utility Plant			
12	Gas plant in service for ratemaking	$43,575,245	$46,639,469	$49,963,792
13				
14	Construction work in progress	174,722	174,722	174,722
15	Accumulated depreciation for ratemaking	(20,753,495)	(22,356,239)	(23,899,567)
16	*Total utility plant*	22,996,472	24,457,952	26,238,946
17	Non-Jurisdictional Plant, net	2,097,165	2,097,165	2,097,165
18	Other Property and Investments:			
19	RS Plan Prepayment		0	0
20	Regulatory asset	52,196	52,196	52,196
21	*Total other property and investments*	52,196	52,196	52,196
22				
23	Current Assets:			
24	Cash	802,679	802,679	802,679
25	Customer accounts receivable	624,279	624,279	624,279
26	Unbilled revenues	478,620		
27	Other receivables	255,292		
28	Advances to affiliates	1,340,221	1,340,221	1,340,221
29	Natural gas inventories	722,281	722,281	722,281
30	Materials and supplies	244,244	244,244	244,244
31	Prepayments	331,357	331,357	331,357
32	*Total current assets*	4,798,973	4,065,061	4,065,061
33				
34	**Total Assets and Other Debits**	**$29,944,806**	**$30,672,374**	**$32,453,369**
35				

C2 (R)

Valley Energy, Inc. (PA)
Rate Case with Fully Projected Future Test Year 2026 (R)

Balance Sheets
Years Ended 12/31/2024, 12/31/2025 and 12/31/2026
Answer to 52 Pa. Code 53.52 c[2]

Line	Account Title	Per Books 12/31/2024	Pro Forma 12/31/2025	Pro Forma 12/31/2026
36	**Liabilities and Other Credits**			
37	Proprietary Capital:			
38	Common stock Issued	$768,293	$768,293	$768,293
39	Retained earnings	14,404,719	15,661,483	16,825,663
40	*Total proprietary capital*	15,173,012	16,429,776	17,593,956
41				
42	Long-Term Debt:			
43	Long Term Debt incl Cap Leases	5,838,390	5,201,042	4,514,401
44	*Total long-term debt*	5,838,390	5,201,042	4,514,401
45				
46	Current and Accrued Liabilities:			
47	Cash (over) under	2,650,000	2,708,859	3,972,938
48	Current maturities of Long Term Debt	637,348	686,641	726,017
49	Accounts payable and accruals	924,199	924,199	924,199
50	Due for purchased gas	495,267	495,267	495,267
51	Customer deposits	394,763	394,763	394,763
52	Over collected gas costs	287,624	287,624	287,624
53	*Total current and accrued liabilities*	5,389,201	5,497,353	6,800,808
54				
55	Deferred Credits and Other Liabilities:			
56	Deferred taxes	2,351,600	2,351,600	2,351,600
57	Accrued postretirement cost	816,705	816,705	816,705
58	Regulatory liability	375,898	375,898	375,898
59	*Total deferred credits*	3,544,203	3,544,203	3,544,203
60				
61	**Total Liabilities and Other Credits**	**$29,944,806**	**$30,672,374**	**$32,453,369**

C3 (R)

Valley Energy, Inc. (PA)
Rate Case with Fully Projected Future Test Year 2026 (R)
Original Cost of Utility Plant in Service
Years Ended 12/31/2024, 12/31/2025 and 12/31/2026
Answer to 52 Pa. Code 53.52 c[3]

					Original Cost			Original Cost		
				12/31/2024	Year 2025	Year 2025	12/31/2025	Year 2026	Year 2026	12/31/2026
Line	Acct No.	Account Title		Balance	Additions	Removals	Balance	Additions	Removals	Balance
1	*Distribution Plant.*									
2	114	Gas Plant Acquisition Adjustment		3,361,289			3,361,289			3,361,289
3	366	Trans. Structures and improvements	(A)	117,592	0		117,592	0		117,592
4	367	Trans. Mains	(A)	1,917,201	0		1,917,201	0		1,917,201
5	369	Trans. Meas / Reg Sta Equp	(A)	402,427	0		402,427	0		402,427
6	374	Land & Land Rights		15,652	0		15,652	0		15,652
7	375	Structures and improvements		204,060	1,218,878		1,422,938	457,937		1,880,875
8	376S	Mains- Steel		3,820,156	43,909		3,864,065	44,080		3,908,144
9	376P	Mains- Plastic		11,410,116	223,134	(434)	11,632,816	1,188,320	(404)	12,820,732
10	378	Meas / Reg Sta Equp		1,590,567	406,925		1,997,492	244,879		2,242,371
11	380S	Services- Steel		581,198	0	(9,027)	572,171	0	(10,385)	561,786
12	380P	Services- Plastic		9,843,941	767,950	(1,364)	10,610,526	1,055,387	(14,366)	11,651,547
13	381	Meters		1,945,136	47,842		1,992,978	61,305		2,054,284
14	381RC	Transponders- Res/Comm		1,010,228			1,010,228			1,010,228
15	381AMR	Meters-AMR		282,510	2,009		284,519	9,121		293,640
16	381Prot	Meters-Protection		61,435	10,611		72,046	0		72,046
17	383	House regulators		335,586	4,500		340,086	4,500		344,586
18	385	Indu Meas / Reg Sta Equp		1,260,536	26,400		1,286,936	13,200		1,300,136
19	387	Other equipment		9,978	0		9,978	0		9,978
20	Total Distribution Plant			38,169,608	2,752,157	(10,826)	40,910,940	3,078,729	(25,156)	43,964,513
21										
22	*General Plant*									
23	390	Structures & Improvements		4,055,042	0		4,055,042	0		4,055,042
24	391	Office Furniture & Equipment		1,230,002	6,200		1,236,202	0		1,236,202
25	391C	Computer equipment		147,442	147,442		294,884	125,750		420,634
26	392	Transportation Equipment		1,214,676	80,000		1,294,676	100,000		1,394,676
27	393	Stores Equipment		48,547	20,000		68,547	0		68,547
28	394	Tools, Shop & Garage Equipment		717,363	68,750		786,113	45,000		831,113
29	396	Power Operated		499,528	0		499,528	0		499,528
30	397	Communication Equipment		245,077	500		245,577	0		245,577
31	398	Miscellaneous Equipment		14,718			14,718			14,718
32	301	Intangible plant, organization		22,107			22,107			22,107
33	389	Land & Land Rights		572,424			572,424			572,424
34		Total General Plant		8,766,926	322,892	0	9,089,818	270,750	0	9,360,568
35										
36		Less: Acquisition		(3,361,289)	0	0	(3,361,289)	0	0	(3,361,289)
37		Total Plant in Service		$43,575,245	$3,075,049	($10,826)	$46,639,469	$3,349,479	($25,156)	$49,963,792
38		Less: Clearing, Charged to NY		$46,936,534			$50,000,758			$53,325,081
39				$46,936,534			$50,000,758			$53,325,081

C3 (R)

Valley Energy, Inc. (PA)
Rate Case with Fully Projected Future Test Year 202(
Original Cost of Utility Plant in Service
Years Ended 12/31/2024, 12/31/2025 and 12/31/202
Answer to 52 Pa. Code 53.52 c[3]

Line	Acct No.	Account Title	Depr. Rate	Year 2024 Depr Exp	Accumulated Depreciation 12/31/2024 Balance	Accumulated Depreciation Year 2025 Depr Exp	Accumulated Depreciation Year 2025 Removals	Accumulated Depreciation 12/31/2025 Balance	Accumulated Depreciation Year 2026 Depr Exp	Accumulated Depreciation Year 2026 Removals	Accumulated Depreciation 12/31/2026 Balance	Net Book Value 12/31/2026 Balance
1	*Distribution Plant.*											
2	114	Gas Plant Acquisition Adjustment	3.47%	88,183	2,847,221	116,637		2,963,858	116,637		3,080,494	280,795
3	366	Trans. Structures and improvements	0.62%	730	7,146	729		7,875	729		8,604	108,988
4	367	Trans. Mains	1.79%	34,311	1,225,993	34,318		1,260,311	34,318		1,294,629	622,572
5	369	Trans. Meas / Reg Sta Equp	4.40%	17,723	296,228	17,707		313,935	17,707		331,642	70,785
6	374	Land & Land Rights	4.40%		0	689		689	689		1,377	14,275
7	375	Structures and improvements	2.63%	5,363	105,540	21,395		126,935	43,445		170,380	1,710,495
8	376S	Mains- Steel	3.15%	120,867	2,769,349	121,026		2,890,375	122,412		3,012,788	895,357
9	376P	Mains- Plastic	2.02%	226,954	3,788,947	232,738	(434)	4,021,251	246,985	(404)	4,267,832	8,552,900
10	378	Meas / Reg Sta Equp	6.72%	100,343	1,221,758	120,559		1,342,317	142,459		1,484,776	757,594
11	380S	Services- Steel	3.04%	18,399	218,783	17,668	(9,027)	227,424	17,394	(10,385)	234,433	327,353
12	380P	Services- Plastic	3.41%	318,053	4,396,438	348,772	(1,364)	4,743,846	379,813	(14,366)	5,109,292	6,542,255
13	381	Meters	2.74%	62,737	1,135,963	53,952		1,189,915	55,447		1,245,363	808,921
14	381RC	Transponders- Res/Comm	2.74%	22,968	312,762	27,680		340,442	27,680		368,122	642,106
15	381AMR	Meters-AMR	2.74%	3,870	8,670	7,768		16,438	7,921		24,359	269,281
16	381Prot	Meters-Protection	2.74%	842	1,356	1,829		3,185	1,974		5,159	66,887
17	383	House regulators	3.22%	10,792	260,864	10,878		271,742	11,023		282,766	61,820
18	385	Indu Meas / Reg Sta Equp	4.11%	40,510	856,743	52,351		909,094	53,164		962,258	337,878
19	387	Other equipment	3.66%	364	7,651	365		8,016	365		8,381	1,597
20	Total Distribution Plant			1,073,009	19,461,412	1,187,061	(10,826)	20,637,648	1,280,163	(25,156)	21,892,656	22,071,857
21												
22	*General Plant*											
23	390	Structures & Improvements	2.43%	74,191	870,711	98,538		969,249	98,538		1,067,786	2,987,256
24	391	Office Furniture & Equipment	13.10%	267,559	1,115,240	161,536		1,276,776	0		1,276,776	(40,574)
25	391C	Computer equipment	6.75%	9,552	9,952	14,928		24,880	24,149		49,029	371,605
26	392	Transportation Equipment	12.00%	68,719	1,030,813	150,561		1,181,374	161,361		1,342,735	51,941
27	393	Stores Equipment	6.67%	2,804	25,535	3,905		29,440	4,572		34,012	34,535
28	394	Tools, Shop & Garage Equipment	5.00%	27,591	523,999	37,587		561,586	40,431		602,017	229,096
29	396	Power Operated	11.76%	48,647	382,238	58,744		440,982	58,545		499,528	0
30	397	Communication Equipment	6.67%	10,527	179,026	16,363		195,389	16,380		211,769	33,808
31	398	Miscellaneous Equipment	6.67%	895	1,790	982		2,772	982		3,753	10,965
32	301	Intangible plant, organization	0.00%			0		0	0		0	22,107
33	389	Land & Land Rights	0.00%			0		0	0		0	572,424
34		Total General Plant		510,485	4,139,304	543,145	0	4,682,449	404,957	0	5,087,406	4,273,162
35												
36		Less: Acquisition		(88,183)	(2,847,221)	(116,637)	0	(2,963,858)	(116,637)	0	(3,080,494)	(295,069)
37		Total Plant in Service		$1,495,311	$20,753,495	$1,613,569	($10,826)	$22,356,239	$1,568,484	($25,156)	$23,899,567	$26,049,950
38		Less: Clearing, Charged to NY		(188,077)	$23,600,716	(188,077)			(188,077)			
39				$1,307,234	$23,600,716	$1,425,492			$1,380,407			26,064,224

WP (R)

Valley Energy, Inc. (PA)
Rate Case with Fully Projected Future Test Year 2026 (R)
INDEX TO WORKPAPERS

Line	SCHEDULE	DESCRIPTION	PERIOD
1	Index To Workpapers		
2	Workpaper 1 to Schedule B	Monthly Billing Units, Rates And Revenue	Historic Year December 31, 2024- Present Rates
3	Workpaper 2 to Schedule B	Sales Forecast Summary	Years Ended 12/31/2024, 12/31/2025 and 12/31/2026
4	Workpaper 1 to Schedule C	Not Used	
5	Workpaper 2 to Schedule C	Historic O&M and Future O&M	Years 2024, 2025 and 2026
6	Workpaper 3 to Schedule C	Accumulated Deferred Income Taxes	Years 2017 through 2023
7	Workpaper 4 to Schedule C	Gas Inventory Balances	Years 2014 through 2024
8			

WP1_B (R)

Valley Energy, Inc. (PA)
Rate Case with Fully Projected Future Test Year 2026 (R)
Workpaper 1 to Schedule B
Monthly Billing Units, Rates And Revenue
Historic Year December 31, 2024- Present Rates

Line		Rate R- Residential	Rate C- Commercial	Rate IS- Interruptible Service	Rate SI- Small Industrial	Rate ST- Transport Firm	Rate I Large Industrial Firm	Transport Firm- Contract	Transport. Firm- DDQ	Transport. Interruptible	Total
1		**BILLING UNITS**									
2		**ccf Sales Historic Year December 31, 2024**									
3	Jan-24	811,551	365,787	0	10,435	256,364		1,600,550	144,148	655,932	3,844,767
4	Feb-24	956,056	420,272	510	12,377	204,405		1,379,780	164,362	629,965	3,767,727
5	Mar-24	795,563	345,934	0	10,426	236,787		1,377,870	139,518	634,790	3,540,888
6	Apr-24	649,473	280,142	2,700	6,951	219,126		1,235,070	117,770	615,093	3,126,325
7	May-24	333,846	141,424	26,540	3,133	189,425		1,138,760	72,268	573,425	2,478,821
8	Jun-24	120,653	64,439	46,880	1,115	183,697		1,059,180	40,318	573,002	2,089,284
9	Jul-24	70,730	44,655	20,260	502	218,200		1,041,970	24,564	564,501	1,985,382
10	Aug-24	65,838	45,964	49,050	577	185,912		898,800	28,001	547,490	1,821,632
11	Sep-24	80,481	51,895	41,620	706	176,139		951,280	27,701	516,647	1,846,469
12	Oct-24	104,465	61,978	29,410	669	194,142		1,273,900	30,767	542,916	2,238,247
13	Nov-24	337,301	142,315	21,160	3,182	232,477		1,284,340	63,653	558,810	2,643,238
14	Dec-24	694,442	294,104	13,430	7,618	284,723		1,496,800	122,223	652,438	3,565,778
15		5,020,399	2,258,909	251,560	57,691	2,581,397	0	14,738,300	975,293	7,065,009	32,948,558
16	*Check to Forecast file*	*5,020,399*	*2,258,909*	*251,560*	*57,691*	*1,971,007*		*14,738,300*	*975,293*	*7,675,399*	*32,948,558*
17		**Customers Historic Year December 31, 2024**									
18	Jan-24	6,517	861	1	4	12		2	56	5	7,458
19	Feb-24	6,524	860	1	4	12		2	56	5	7,464
20	Mar-24	6,529	860	1	4	12		2	56	5	7,469
21	Apr-24	6,494	855	1	4	12		2	56	5	7,429
22	May-24	6,466	852	1	4	12		2	56	5	7,398
23	Jun-24	6,451	850	1	4	12		2	56	5	7,381
24	Jul-24	6,423	849	1	4	12		2	56	5	7,352
25	Aug-24	6,416	850	1	4	12		2	56	5	7,346
26	Sep-24	6,437	850	1	4	12		2	56	5	7,367
27	Oct-24	6,504	853	1	4	12		2	56	5	7,437
28	Nov-24	6,504	853	1	4	12		2	56	5	7,437
29	Dec-24	6,565	857	1	4	12		2	56	5	7,502
30	Annual Bills	77,830	10,250	12	48	144	0	24	672	60	89,040
31	Average Monthly Bills	6,486	854	1	4	12	0	2	56	5	7,420
32		**RATES AND CHARGES**									
33		**Tariff Rates**									
34	Customer Charge Tariff	$12.35	$21.95	$82.00	$82.00	$82.00			$21.95	$82.00	
35											
36	Commodity Block 1	$0.37095	$0.27929	$0.086720	$0.186900	$0.186900	$0.050300		$0.279290	$0.086720	
42	GCR Jan-Oct $0.33758	$0.33758	$0.33758	$0.33758	$0.33758						
43	GCR Nov-Dec $0.34569	$0.34569	$0.34569	$0.34569	$0.34569						

WP1_B (R)

Valley Energy, Inc. (PA)
Rate Case with Fully Projected Future Test Year 2026 (R)
Workpaper 1 to Schedule B
Monthly Billing Units, Rates And Revenue
Historic Year December 31, 2024- Present Rates

Line		Rate R- Residential	Rate C- Commercial	Rate IS- Interruptible Service	Rate SI- Small Industrial	Rate ST- Transport Firm	Rate I Large Industrial Firm	Transport Firm- Contract	Transport. Firm- DDQ	Transport. Interruptible	Total
44						**COMPUTATION OF REVENUE**					
45						**Customer Charge Revenue**					
46	Jan-24	$80,485	$18,899	$82	$328	$984			$1,229	$410	$102,007
47	Feb-24	80,571	18,877	82	328	984			1,229	410	$102,072
48	Mar-24	80,633	18,877	82	328	984			1,229	410	$102,133
49	Apr-24	80,201	18,767	82	328	984			1,229	410	$101,591
50	May-24	79,855	18,701	82	328	984			1,229	410	$101,180
51	Jun-24	79,670	18,658	82	328	984			1,229	410	$100,951
52	Jul-24	79,324	18,636	82	328	984			1,229	410	$100,583
53	Aug-24	79,238	18,658	82	328	984			1,229	410	$100,518
54	Sep-24	79,497	18,658	82	328	984			1,229	410	$100,778
55	Oct-24	80,324	18,723	82	328	984			1,229	410	$101,671
56	Nov-24	80,324	18,723	82	328	984			1,229	410	$101,671
57	Dec-24	81,078	18,811	82	328	984			1,229	410	$102,512
58		$961,201	$224,988	$984	$3,936	$11,808	$0	$0	$14,750	$4,920	$1,217,666
59											
60						**Distribution ccf Revenue**					
61	Jan-24	$301,045	$102,161	$0	$1,950	$47,914		$76,270	$40,259	$56,882	$569,600
62	Feb-24	$354,649	$117,378	$44	$2,313	$38,203		$72,085	$45,905	$54,631	$630,577
63	Mar-24	$295,114	$96,616	$0	$1,949	$44,255		$70,384	$38,966	$55,049	$547,284
64	Apr-24	$240,922	$78,241	$234	$1,299	$40,955		$68,491	$32,892	$53,341	$463,034
65	May-24	$123,840	$39,498	$2,302	$586	$35,404		$65,517	$20,184	$49,727	$287,329
66	Jun-24	$44,756	$17,997	$4,065	$208	$34,333		$65,035	$11,260	$49,691	$177,656
67	Jul-24	$26,237	$12,472	$1,757	$94	$40,782		$62,614	$6,860	$48,954	$150,816
68	Aug-24	$24,423	$12,837	$4,254	$108	$34,747		$53,080	$7,820	$47,478	$137,269
69	Sep-24	$29,854	$14,494	$3,609	$132	$32,920		$64,033	$7,737	$44,804	$152,780
70	Oct-24	$38,751	$17,310	$2,550	$125	$36,285		$70,301	$8,593	$47,082	$173,916
71	Nov-24	$125,122	$39,747	$1,835	$595	$43,450		$72,832	$17,778	$48,460	$301,358
72	Dec-24	$257,603	$82,140	$1,165	$1,424	$53,215		$77,784	$34,136	$56,579	$507,467
73		$1,862,317	$630,891	$21,815	$10,782	$482,463	$0	$818,427	$272,390	$612,678	$4,099,085
74											

WP1_B (R)

Valley Energy, Inc. (PA)
Rate Case with Fully Projected Future Test Year 2026 (R)
Workpaper 1 to Schedule B
Monthly Billing Units, Rates And Revenue
Historic Year December 31, 2024- Present Rates

Line		Rate R- Residential	Rate C- Commercial	Rate IS- Interruptible Service	Rate SI- Small Industrial	Rate ST- Transport Firm	Rate I Large Industrial Firm	Transport Firm- Contract	Transport. Firm- DDQ	Transport. Interruptible	Total
75						**GCR Revenue**					
76	Jan-24	$273,963	$123,482	$0	$3,523						$400,968
77	Feb-24	322,745	141,875	172	4,178						$468,971
78	Mar-24	268,566	116,780	0	3,520						$388,866
79	Apr-24	219,249	94,570	911	2,347						$317,077
80	May-24	112,700	47,742	8,959	1,058						$170,459
81	Jun-24	40,730	21,753	15,826	376						$78,686
82	Jul-24	23,877	15,075	6,839	169						$45,961
83	Aug-24	22,226	15,517	16,558	195						$54,495
84	Sep-24	27,169	17,519	14,050	238						$58,976
85	Oct-24	35,265	20,923	9,928	226						$66,342
86	Nov-24	116,602	49,197	7,315	1,100						$174,213
87	Dec-24	240,062	101,669	4,643	2,633						$349,007
88		$1,703,154	$766,102	$85,202	$19,563	$0	$0	$0	$0	$0	$2,574,021
89											
90						**Total Revenue**					
91	Jan-24	$655,493	$244,542	$82	$5,801	$48,898	$0	$76,270	$41,488	$57,292	$1,129,867
92	Feb-24	757,966	278,130	298	6,819	39,187	0	72,085	47,134	55,041	$1,256,661
93	Mar-24	644,313	232,273	82	5,796	45,239	0	70,384	40,195	55,459	$1,093,743
94	Apr-24	540,372	191,578	1,228	3,974	41,939	0	68,491	34,121	53,751	$935,454
95	May-24	316,395	105,942	11,343	1,971	36,388	0	65,517	21,413	50,137	$609,105
96	Jun-24	165,156	58,408	19,973	913	35,317	0	65,035	12,490	50,101	$407,393
97	Jul-24	129,438	46,182	8,678	591	41,766	0	62,614	8,090	49,364	$346,722
98	Aug-24	125,886	47,011	20,894	631	35,731	0	53,080	9,050	47,888	$340,170
99	Sep-24	136,520	50,670	17,741	698	33,904	0	64,033	8,966	45,214	$357,747
100	Oct-24	154,341	56,956	12,561	679	37,269	0	70,301	9,822	47,492	$389,420
101	Nov-24	322,048	107,667	9,232	2,023	44,434	0	72,832	19,007	48,870	$626,113
102	Dec-24	578,743	202,620	5,889	4,385	54,199	0	77,784	35,365	56,989	$1,015,975
103		$4,526,671	$1,621,980	$108,001	$34,281	$494,271	$0	$818,427	$287,140	$617,598	$8,508,370

WP2_C (R)

Valley Energy, Inc. (PA)
Rate Case with Fully Projected Future Test Year 2026 (R)
Workpaper 2 to Schedule C
Historic O&M and Future O&M
Years 2024, 2025 and 2026

Line	Dept.	Account	rType22	rAcct25	rFTY24 Total 2024	rFTY25 Total 2025	rFPFTY26 Total 2026
1	**PAYROLL - DIRECT LABOR**						
2	LABOR OPER SUPR & ENG	870.01	Labor	870	91,173	103,788	113,359
3	LABOR MAINS & SERV EXP	874.01	Labor	874	130,294	136,278	193,236
4	LABOR MEAS & REG STAT EXP	875.01	Labor	875	37,665	35,758	40,056
5	LABOR IND/CM MTR/REG MNT	876.01	Labor	876	39,962	31,539	36,372
6	LABOR MEAS & REG CITY GATE	877.01	Labor	877	8,437	6,288	7,065
7	LABOR MTR/HSE REG EXP	878.01	Labor	878	67,681	60,218	67,498
8	LABOR CUST INSTALL EXP	879.01	Labor	879	82,768	72,453	80,239
9	LABOR OQ TRAINING	880.01	Labor	880	41,265	20,603	27,982
10	LABOR MAINT SUPV & ENG	885.01	Labor	885	14,259	15,514	16,318
11	LABOR STURCTURES & IMPR	886.01	Labor	886	7,393	7,488	6,038
12	LABOR MAINT OF MAIN	887.01	Labor	887	31,237	36,769	43,282
13	LABOR MEAS & REG STAT EQUIP	889.01	Labor	889	25,905	20,343	18,035
14	LABOR MAINT. INDUST. M&R STA	890.01	Labor	890	8,834	8,837	10,141
15	LABOR MAINT CITY GATE STAT	891.01	Labor	891	1,736	1,715	1,979
16	LABOR MAINT OF SERVICE	892.01	Labor	892	19,182	20,480	26,012
17	LABOR MAINT MTR & HSE REG	893.01	Labor	893	44,570	29,166	23,748
18	LABOR METER READING EXP	902.01	Labor	902	8,187	9,734	6,193
19	LABOR CUST REC/COLLECTIONS	903.01	Labor	903	194,876	214,654	229,723
20	LABOR ADMINISTRATION	920.01	Labor	920	278,745	276,347	298,043
21	LABOR GENERAL PLT MAINTENAI	932.01	Labor	932	6,764	8,168	8,203
22	**Total Direct Labor**				**1,140,934**	**1,116,140**	**1,253,522**
23							
24	TRANSP OPER SUPR & ENG	870.02	Trans	870	4,816	8,447	8,700
25	TRANSP MAINS & SERVICE EXP	874.02	Trans	874	38,119	30,734	31,656
26	TRNSP MEAS & REG STAT EXP	875.02	Trans	875	7,847	8,638	8,897
27	TRANS IND/CM/MTR/REG/MNT	876.02	Trans	876	5,113	4,480	4,614
28	TRANSP MEAS & REG CITY GATE	877.02	Trans	877	2,491	2,640	2,719
29	TRANSP MTR/HSE REG EXP	878.02	Trans	878	9,202	8,833	9,098
30	TRANSP CUST INSTALL EXP	879.02	Trans	879	7,334	11,297	11,636
31	TRANSP OQ TRAINING	880.02	Trans	880	201	136	140
32	TRANSP MAINT SUPV & ENG	885.02	Trans	885	3,384	3,271	3,369
33	TRANSP MAINT STRUCTURES & II	886.02	Trans	886	624	653	673
34	TRANSP MAINT OF MAIN	887.02	Trans	887	5,137	5,210	5,366
35	TRANSP MAINT MEAS/REG STAT	889.02	Trans	889	789	1,461	1,505
36	TRANSP MAINT INDUS M&R STAT	890.02	Trans	890	297	212	218
37	TRANSP MAINT CITY GATE STAT	891.02	Trans	891	335	756	779
38	TRANSP MAINT OF SERVICE	892.02	Trans	892	6,088	7,657	7,887
39	TRANSP MAINT MTR HSE REG	893.02	Trans	893	2,600	2,134	2,198
40	TRANS METER READING EXP	902.02	Trans	902	2,494	2,499	2,574
41	TRANSP CUST REC/COLLECTION:	903.02	Trans	903	3,618	3,923	4,041
42	TRANSP ADMINSTRATION	920.02	Trans	920	20,537	18,770	19,333
43	TRANS MAINT GENERAL PLANT	932.02	Trans	932	1,931	1,518	1,564
44	**Total Trans. Exp**				**122,958**	**123,269**	**126,967**
45							

WP2_C (R)

Valley Energy, Inc. (PA)
Rate Case with Fully Projected Future Test Year 2026 (R)
Workpaper 2 to Schedule C
Historic O&M and Future O&M
Years 2024, 2025 and 2026

Line	Dept.	Account	rType22	rAcct25	rFTY24 Total 2024	rFTY25 Total 2025	rFPFTY26 Total 2026
46	C&T OH OPER SUPR & ENG	870.03	OH	870	25,914	26,794	29,264
47	C&T OH MAINS & SERVICE EXP	874.03	OH	874	36,637	35,181	49,885
48	C&T OH MEAS & REG STAT EXP	875.03	OH	875	10,568	9,231	10,341
49	C&T OH IND/CM MTR/REG MNT	876.03	OH	876	11,249	8,142	9,390
50	C&T OH CITY GATE MEAS/REG ST	877.03	OH	877	2,324	1,623	1,824
51	C&T OH MTR/HSE REG EXP	878.03	OH	878	19,382	15,546	17,425
52	C&T OH CUST INSTALL EXP	879.03	OH	879	23,504	18,704	20,714
53	C&T OH OQ TRAINING	880.03	OH	880	11,802	5,319	7,224
54	C&T OH MAINT SUPV & ENG	885.03	OH	885	4,018	4,005	4,213
55	C&T OH MAINT STRUCTURES & IN	886.03	OH	886	2,140	1,933	1,559
56	C&T OH MAINT OF MAIN	887.03	OH	887	9,637	9,492	11,174
57	C&T OH MAINT M&R STAT EQUIP	889.03	OH	889	7,343	5,252	4,656
58	C&T OH MAINT INDUST M&R STAT	890.03	OH	890	2,463	2,281	2,618
59	C&T OH MAINT CITY GATE STAT	891.03	OH	891	505	443	511
60	C&T OH MAINT SERVICES EXP	892.03	OH	892	6,126	5,287	6,715
61	C&T OH MAINT MTR & HSE REG	893.03	OH	893	12,808	7,529	6,131
62	C&T OH METER READING EXP	902.03	OH	902	2,337	2,513	1,599
63	C&T OH CUST REC/COLLECTIONS	903.03	OH	903	54,926	55,414	59,305
64	C&T OH ADMINSTRATION	920.03	OH	920	79,170	71,341	76,942
65	C&T OVHD GENERAL PLANT	923.03	OH	923	1,914	2,109	2,118
66	**Total C&T OH**				**324,768**	**288,139**	**323,605**
67							
68	VE OH OPER SUPR & ENG	870.05	OH	870	91,050	100,001	109,223
69	VE OH MAINS & SERVICE EXP	874.05	OH	874	128,621	131,306	186,186
70	VE OH MEAS & REG STAT EXP	875.05	OH	875	36,903	34,453	36,913
71	VE OH IND/CM/MTR/REG MNT EXP	876.05	OH	876	39,820	30,388	34,862
72	VE OH CITY GATE MEAS & REG	877.05	OH	877	7,822	6,059	6,475
73	VE OH MTR/HSE REG EXP	878.05	OH	878	67,995	58,021	63,918
74	VE OH CUST INSTALL EXP	879.05	OH	879	82,790	69,810	76,507
75	VE OH OQ TRAINING	880.03	OH	880	40,283	19,851	26,556
76	VE OH MAINT SUPV & ENG	885.05	OH	885	13,346	14,948	15,723
77	VE OH MAINT STRUCTURES & IMP	886.05	OH	886	7,734	7,215	2,498
78	VE OH MAINT OF MAIN	887.05	OH	887	30,636	35,428	41,703
79	VE OH MAINT M&R STAT EQUIP	889.05	OH	889	23,854	19,601	8,839
80	VE OH MAINT. INDUSTR. M&R STA	890.05	OH	890	8,418	8,515	9,482
81	VE OH MAINT CITY GATE STAT	891.05	OH	891	1,695	1,652	1,907
82	VE OH MAINT OF SERVICE	892.05	OH	892	17,316	19,733	25,063
83	LABOR OH MAINT MTR & HSE REG	893.05	OH	893	45,006	28,102	7,931
84	VE OH METER READING EXP	902.05	OH	902	8,313	9,379	2,522
85	VE OH CUST REC/COLLECTIONS	903.05	OH	903	193,246	206,823	218,985
86	VE OH ADMINISTRATION	920.05	OH	920	275,205	266,265	287,169
87	OH MAINT PLANT	932.05	OH	932	6,833	7,870	5,527
88	**Total VE Labor OH**				**1,126,888**	**1,075,419**	**1,167,988**
89							
90							

WP2_C (R)

Valley Energy, Inc. (PA)
Rate Case with Fully Projected Future Test Year 2026 (R)
Workpaper 2 to Schedule C
Historic O&M and Future O&M
Years 2024, 2025 and 2026

			rType22	*rAcct25*	*rFTY24*	*rFTY25*	*rFPFTY26*
Line	**Dept.**	**Account**			**Total 2024**	**Total 2025**	**Total 2026**
91	FUEL (COMPANY USE)	842.10	Other	842	21,175	21,130	20,347
92	DISTRIB LOAD DISPATCHING	871.45	Mat	871	6,180	6,763	7,101
93	MAT & SUP MAINS & SERV EXP	874.45	Mat	874	23,767	32,675	32,675
94	CALL CENTER EXPENSE	874.50	Other	874	72,342	74,285	76,514
95	TOOLS, EQUIPMENT & MAINTENA	874.99	Mat	874	25,045	10,029	10,330
96	MAT/SUP MEAS & REG STAT EXP	875.45	Mat	875	9,236	10,207	10,513
97	MAT & SUP IND/CM/MTR/REG/MN	876.45	Mat	876	6,318	7,968	9,164
98	MAT/SUP CITYGATE MEAS/REG S	877.45	Mat	877	13,387	13,637	14,046
99	MAT & SUP MTR/HSE REG EXP	878.45	Mat	878	1,585	1,634	1,683
100	MAT/SUP CUST INSTALL EXP	879.45	Mat	879	946	920	947
101	MAT/SUP OQ TRAINING	880.45	Mat	880	21,154	8,526	8,782
102	RENTS - DISTRIBUTION EXPENSE	881.45	Mat	881	5,803	6,222	6,669
103	MAT/SUP MAINT STRUCTURE/IMP	886.45	Mat	886	21,033	9,176	9,451
104	MAT/SUPP MAINT OF MAIN	887.45	Mat	887	31,010	31,010	31,940
105	MAT/SUP MAINT M&R STAT EQUIF	889.45	Mat	889	18,446	18,998	19,568
106	MAT/SUP MAINT M&R INDUST EQ	890.45	Mat	890	3,610	3,718	3,830
107	MAT/SUP MAINT CITY GATE STAT	891.45	Mat	891	2,655	3,323	7,616
108	MAT/SUP MAINT OF SERVICES	892.45	Mat	892	5,307	5,440	5,604
109	MAT/SUPP MAINT MTR & HSE RE(	893.45	Mat	893	20,042	13,945	14,364
110							
111	MAT/SUPP METER READING EXP	902.45	Mat	902	4,265	3,981	4,100
112	NISC BILLING	903.25	Other	903	109,746	111,397	112,891
113	MAT/SUP CUST REC/COLLECTION	903.45	Mat	903	40,327	29,837	30,732
114	DOLLAR ENERGY FUND EXPENSE	903.55	Other	903	13,735	5,927	5,927
115	BAD DEBT EXPENSE	904.00	Other	904	(20,260)	50,495	54,348
116	MAT/SUP MISC CUST ACCT EXP	905.45	Mat	905	19,214	21,492	21,492
117	INFORMATION/INSTRUCTIONAL E	909.45	Mat	909	12,402	12,774	13,157
118	ADVERTISING EXPENSES	913.45	Mat	913	1,998	2,057	2,098
119							
120	MAT/SUP ADMINISTRATIVE	920.45	Mat	920	66	68	69
121	GENERAL OFFICE SUPPLIES & E>	921.00	Other	921	10,761	12,054	12,054
122	MEAL EXPENSES	921.40	Other	921	8,346	9,132	9,406

WP2_C (R)

Valley Energy, Inc. (PA)
Rate Case with Fully Projected Future Test Year 2026 (R)
Workpaper 2 to Schedule C
Historic O&M and Future O&M
Years 2024, 2025 and 2026

Line	Dept.	Account	*rType22*	*rAcct25*	*rFTY24* Total 2024	*rFTY25* Total 2025	*rFPFTY26* Total 2026
123	TRAVEL AND TRAINING	921.45	Other	921	16,810	40,834	42,059
124	COMMUNICATION EQUIP	921.50	Other	921	20,559	17,350	17,871
125	OUTSIDE SERVICES EMPLOYED	923.00	Other	923	23,880	25,452	26,215
126	AUDITOR FEES EXPENSE	923.25	Other	923	40,495	43,735	47,233
127	GCR EXPENSE	923.40	Other	923	-	-	-
128	ATTORNEY FEES EXPENSE	923.45	Other	923	17,020	8,152	8,560
	IE-RE-40		Other	923	1,248	(2,109)	(2,118)
129	INSURANCE ST OPENING BONDS	925.10	Other	925	500	500	500
130	PROPERTY INSURANCE EXPENSI	924.00	Other	924	23,202	36,257	41,699
	Property Insuance CTZ 5R		Other	924			(2,880)
131	INJURIES AND DAMAGES	925.00	Other	925	93,400	108,157	124,381
	Lower Insurance CTZ-5R	925.00	Other	925			(30,981)
132	EMPLOYEE BENEFITS-DIRECT EX	926.45	Other	926	6,502	9,898	10,194
133	REGULATORY COMMISSION EXPI	928.00	Other	928	89,218	99,514	105,514
	REGULATORY COMMISSION EXPI	928.00	Other	928			(58,195)
134	MISCELLANEOUS GENERAL EXPE	930.20	Other	930	234	28,363	30,751
135	LABOR - VOLUNTEER	930.21	Other	930	3,091	187	216
136	DUES/COMPANY MEMBERSHIPS	930.22	Other	930	16,378	16,791	17,295
137	COVID-Related	930CV	Other	930CV	-	-	-
138	DIRECTOR EXPENSE	930.25	Other	930	52,543	58,639	57,047
139	DIRECTOR EXP. - TRAVEL/TRAINI	930.45	Other	930	-	-	1,309
	IE-RE-40		Other	930		(1,119)	(1,176)
	Advertising / Dues CTZ 5R		Other	930			(1,344)
140	MAINT GENERAL PLANT	932.45	Mat	932	21,814	23,249	23,946
141	**Total Direct Expenses**				**936,532**	**1,052,670**	**1,015,514**
142					3,652,079	3,655,637	3,887,597
143					3,653,994	3,662,186	3,987,778
144					3,653,994	3,662,186	3,987,778
145							
146							
147			Other		620,924	775,021	725,637
148			Mat		315,608	277,649	289,877
149					936,532	1,052,670	1,015,514

WP3_C (R)

Valley Energy, Inc. (PA)
Rate Case with Fully Projected Future Test Year 2026 (R)
Workpaper 3 to Schedule C
Accumulated Deferred Income Taxes
Years 2017 through 2023

Line	Valley PA	2024	2025	2026
1				
2				
3	Book	20,753,495	22,356,239	23,899,567
4				
5	Federal Tax - MACRS	39,787,591	41,500,668	43,353,900
6				
7	Federal Tax - SL	37,481,985	39,313,415	41,266,769
8				
9	PA Tax	31,804,320	33,607,026	36,524,778
10				
11	Federal Tax Depr Exp - MACRS	1,515,837	1,723,903	1,878,388
12				
13	Federal Tax Depr Exp - SL	1,763,836	1,842,256	1,978,510
14				
15	PA Tax Depr Exp	2,115,013	2,528,871	2,227,569

WP4_C (R)

Valley Energy, Inc. (PA)
Rate Case with Fully Projected Future Test Year 2026 (R)
Workpaper 4 to Schedule C
Gas Inventory Balances
Years 2014 through 2024

Line	Volumes dth	Average	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
1	January	308,104	239,316	316,185	324,010	303,966	288,448	262,049	348,294	345,770	303,388	361,839	295,881
2	February	211,139	137,330	205,138	216,106	205,227	199,441	162,488	235,743	230,927	215,472	295,748	218,910
3	March	136,269	73,110	87,111	123,140	104,509	90,857	82,198	221,307	180,789	130,668	238,899	166,375
4	April	174,267	102,115	134,840	161,039	158,026	140,091	133,872	249,101	222,236	151,635	265,765	198,220
5	May	239,064	164,566	199,779	229,451	219,484	208,626	200,548	315,055	284,125	223,061	319,327	265,678
6	June	307,529	235,210	272,102	296,747	299,653	270,023	269,114	374,779	352,519	292,226	383,864	336,583
7	July	373,837	310,689	343,498	369,243	377,771	348,425	343,384	416,525	428,834	359,138	436,959	377,736
8	August	436,884	380,552	415,982	440,488	447,551	409,464	415,442	469,372	485,143	428,867	484,617	428,250
9	September	501,109	458,095	480,148	510,136	509,996	490,264	479,213	549,092	530,928	504,539	509,438	490,348
10	October	534,969	533,294	529,372	533,064	538,540	522,002	540,177	554,292	560,526	548,887	521,062	503,443
11	November	508,017	517,763	507,262	509,242	500,821	476,879	509,961	553,870	536,555	523,727	489,542	462,568
12	December	429,430	446,279	436,961	421,771	410,292	394,290	429,939	459,074	470,770	446,356	443,121	364,873
13													
14													
15	**Average volu**	**346,718**	dth										
16	GCR at Preser	$3.45690	per dth										
17	**Inventory Va**	**1,198,570**											
18													

BEFORE

THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	**:**	
	:	
v.	**:**	**Docket No. R-2025-3054393**
	:	
Valley Energy, Inc.	**:**	

SURREBUTTAL TESTIMONY

OF

HOWARD S. GORMAN

ON BEHALF OF

VALLEY ENERGY, INC.

AUGUST 28, 2025

BEFORE

THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	**Docket No. R-2025-3054393**
	:	
Valley Energy, Inc.	:	

SURREBUTTAL TESTIMONY OF HOWARD S. GORMAN
ON BEHALF OF VALLEY ENERGY, INC.

Q. Please state your name, occupation and business address.

A. My name is Howard Gorman. I am the President of HSG Group, Inc., a consulting firm specializing in utility rate and regulatory matters, located in Great Neck, NY.

Q. Are you the same Howard Gorman that provided Direct Testimony on behalf of Valley Energy, Inc. ("Valley" or "Company")?

A. Yes. Terms defined in my Direct Testimony or my Rebuttal Testimony have the same meaning in this Surrebuttal Testimony.

Q. What is the purpose of your testimony today?

A. The purpose of my testimony is to respond to the Rebuttal Testimony of the following witness:

- Office of Consumer Advocate ("OCA") Witness Myer (OCA St. 1R)

Q. Are you sponsoring any exhibits today?

A. No.

Q. Are you supporting any changes to the Company's filing, as amended by Exhibit___(HSG-1R)?

A. No.

Q. Please summarize your review of the Rebuttal Testimony of Mr. Meyer (OCA St. 1R).

A. Mr. Meyer did not raise any new issues or provide any new arguments for his positions. Mr. Meyer addresses two adjustments that were suggested in the Direct Testimony by other parties. Valley accepted one of those adjustments (Tax Rate). I addressed the other adjustment (Unamortized Rate Case Expense) in my Rebuttal Testimony. Mr. Meyer has not raised any arguments that I have not fully refuted.

Q. Please discuss the source document error that Mr. Meyer references in his Rebuttal Testimony.

A. In the course of responding to discovery, Valley alerted the parties that a limited subset of data for the Future Test Year ("FTY") was not pulled from the final version of the Company's files. This data error did not impact the Fully Projected Future Test Year ("FPFTY") that supports the Company's claim. This oversight was detected and corrected through revised schedules previously distributed to the parties.

Q. Does this conclude your Surrebuttal Testimony today?

A. Yes.

Valley Statement No. 4

BEFORE
THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	**:**	
	:	
v.	**:**	**Docket No. R-2025-_____**
	:	
Valley Energy, Inc.	**:**	

DIRECT TESTIMONY
AND EXHIBIT

OF

EDWARD E. ROGERS

ON BEHALF OF

VALLEY ENERGY, INC.

APRIL 30, 2025

BEFORE
THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	**:**	
	:	
v.	**:**	**Docket No. R-2025-_____**
	:	
Valley Energy, Inc.	**:**	

DIRECT TESTIMONY OF EDWARD E. ROGERS
ON BEHALF OF VALLEY ENERGY, INC.

Q. Please state your name and business address.

A. My name is Edward E. Rogers. My business address is 523 Keystone Avenue, Sayre, Pennsylvania.

Q. By whom are you employed and what position do you hold with Valley Energy, Inc.?

A. I am employed by C&T Enterprises, Inc., and assigned to Valley Energy, Inc. ("Valley" or "Company"), as the President and Chief Executive Officer.

Q. What are your duties in that capacity?

A. My duties include the management of all administrative, engineering, operations, safety, compliance, and customer service activities of Valley.

Q. Please describe your educational and professional background.

A. I attended Marquette University as a computational mathematics major from 1980 to 1982 and enrolled in Pennsylvania State University's Mechanical Engineering Technology Program from 1989 to 1991. I worked for various construction firms prior to joining Valley.

Q. Please describe the purpose of your testimony.

A. My testimony provides a general overview of Valley, its operations, service territory, and customer base. I will discuss the major factors that necessitate the rate relief that we are requesting. I also discuss proposed changes to the tariff.

Q. Please provide a brief corporate history of Valley.

A. Valley was formed by C&T Enterprises in 2000 to purchase from NUI Corporation ("NUI") the assets of Valley Cities Gas Service and Waverly Gas Service. Ownership and operational control of the assets was transferred to Valley on November 7, 2002.

In 1944, Pennsylvania & Southern Gas Company formed Valley Cities by acquiring the following companies: The Athens and Sayre Gas Company (originally formed in 1899); The Athens, Sayre and South Waverly Heat and Power Company (originally formed in 1899); and The South Waverly Gas Light Company (originally formed in 1885). Pennsylvania & Southern added the Towanda portion of the service territory from Towanda Gas and Water Company (originally formed in 1859) in 1945. Finally, The Waverly Gas Light Company (1883) was acquired in 1959. Pennsylvania & Southern operated the combined assets (known as Valley Cities Gas in Pennsylvania and Waverly Gas in New York) through 1994. In 1994, NUI acquired Pennsylvania & Southern.

Q. Please describe the current service territory for Valley.

A. Valley serves twelve communities in Bradford County, Pennsylvania, and Tioga and Chemung Counties in New York. Valley supplies natural gas to more than 7,349 residential, commercial and industrial customers in Pennsylvania. Our

Pennsylvania natural gas distribution system includes over 167 miles of mains. We operate the Pennsylvania and New York systems as an integrated system, with all natural gas injected into the system at points in Pennsylvania.

Q. How does Valley arrange the gas supplies for its system?

A. Valley has two interconnection gate stations with the Tennessee Gas pipeline system. One point currently serves the Hamilton (previously Panda) electric generation station that is located south of Towanda. The other interconnection serves the remainder of our system, including Valley's customers in New York. We hold firm capacity contracts on Tennessee and also have various storage contracts.

Q. In what year was the last filing to adjust the base rates for customers on the Valley system?

A. The last base rate proceeding adjusting rates for Valley customers was in 2022, with new rates taking effect on February 1, 2023. In that case, Valley settled with the other parties to obtain an annual revenue increase of $958,000.

Q. Why is Valley requesting to increase its rates?

A. The primary reason that we are submitting this filing is to ensure the continued financial viability of the company. We must continue to earn an appropriate return on our rate base investments and cover our expenses. Operating costs continue to increase throughout the economy. We also continue to replace equipment, mains, pipelines and services, which increases our rate base. Mr. Chapman will address the past and future enhancements to utility plant in more detail.

We also are experiencing other material and supply increases for everything from office supplies to vehicle fuels. Ms. Beale will address our current and future expenses in her testimony.

As the analysis conducted by Mr. Gorman indicates, Valley's pro forma return on rate base for historic year 2024 was 4.3%. *See* Exhibit__(HSG-1), Schedule C1. Without a rate increase, the Company projects a return on rate base of only 3.72% for 2025. *Id.* Using an appropriate market-reflective return on equity ("ROE") as Mr. D'Ascendis and Mr. Kucan recommend in their testimony would establish rates that provide Valley with the opportunity to earn a return on rate base of 8.27% and result in a proposed rate increase of $1.6 million.

Q. Is Valley seeking the full rate increase to which it is entitled?

A. Yes. The Commission recently adopted changes to its regulations to allow smaller companies to proceed with non-major rate cases for amounts up to $5 million. Although the revised regulations have not been published in the *Pennsylvania Bulletin*, we are asking for the full amount pending that publication.

We have added to our filing information requested under the existing regulations for rate increase requests that exceed $1 million, as specified in Section 53.53 of the regulations.

Q. Has Valley been pursuing a systemic improvement of the distribution system over the last ten years?

A. Yes. Valley has continued to make significant improvements to the distribution system to enhance service, safety and reliability. As Mr. Chapman addresses in more detail, we prepare periodic Distribution Management Integrity Plans

("DIMPs"), which provide a systematic approach for maintaining the reliability of our system. Our annual capital plans then include projects to address the risks identified in the DIMP, as well as known major replacement/improvement projects by PennDOT and other utilities in our area, and other necessary capital improvements.

Valley has been proactive in addressing reliability throughout the years. For example, Valley completed the replacement of all cast iron and bare steel pipe on its system 8 years ago. We now are working through the replacement of troubled Aldyl-A vintage plastic pipelines and service lines, which we project to have fully replaced within 3 to 5 years.

Over the last ten years, the Company has also performed upgrades to its City Gate facility; upgraded transmission mains; added, replaced or upgraded 14 district regulator stations; installed over 26 miles of new or replacement plastic gas mains; installed 2,383 new or replacement services; relocated over 107 meters from indoors to outdoors; added remote pressure monitoring devices; installed additional over-pressure protection equipment on low-pressure systems and added or replaced 36 large commercial metering facilities.

Valley's prudent management and attention to its distribution system has resulted in an excellent safety record. We also have one of the lowest lost and unaccounted for gas percentages in Pennsylvania, which saves our ratepayers money on their supply service. Attached as Exhibit__(EER-1) is a table showing our historic lost and unaccounted gas performance.

Q. Does Valley anticipate any major capital projects to enhance its building and facilities?

A. Yes. In late 2024, Valley purchased a property that will be used for warehousing construction equipment, as work space for construction crews, to locate a pressure regulation shop, and as a training center. We are in the process of making upgrades to that facility, which will be completed in 2026.

Q. Why is Valley adding a training center?

A. The Office of Pipeline Safety of the U.S. DOT, requires operators to develop and maintain a qualification program for individuals performing tasks identified in the regulation (i.e., investigating leak or odor complaints). To comply with the requirements of this regulation, Valley Energy implemented an Operator Qualification (OQ) Program. The intent of the OQ regulation is to minimize human error by establishing a verifiable qualified workforce. The training component of the OQ Program continues to increase and evolve, resulting in increased training and testing hours. To meet the OQ program training requirements, increased instructor led, scenario-based training is required as the number of tasks that require a hands-on component to fully qualify for a task continues to increase. Employees are required to train in specific tasks and demonstrate their proficiency in those tasks through the successful completion of a written and/or performance-based evaluation. The continued evolution of the requirements pertaining to OQ rules and the increase in performance-based tasks continue to highlight the need for augmented training facilities which would enable scenario-based training for gas pipe installation and repair functions.

While on-the-job training is still occurring and will occur into the future, the Company will have the ability to enhance on-the-job training with the addition of live, scenario-based hands-on training that will be utilized in the new training center. This will provide us with the ability to train our employees on equipment and in conditions that mimic the real-world environment, but in a safe, controlled manner.

Investing in employee development through dedicated training resources and formal standardized training programs will, as discussed earlier, provide greater depth, consistency and frequency to employee training. Additionally, the new programs will enable the Company to adequately respond to emerging trends in the rapidly changing utility industry while simultaneously managing continuous changes in the workforce as experienced employees retire. Training and development has never been more important or critical to keep pace with the changes in our business.

Q. Does this property also enhance Valley's ability to serve its customers?

A. Yes. The property is strategically located in the northern portion of our territory and provides ready access to our service territory for our construction crews and the regulator technician.

SMALL UTILITY ISSUES AND COMPANY PERFORMANCE

Q. Mr. Rogers, is it accurate to categorize Valley as a small utility?

A. Yes. I already mentioned that Valley serves less than 7,500 customers in Pennsylvania. Similarly, the market capitalization analysis in the Direct Testimony

of Company witnesses Dylan D'Ascendis and Ryan Kucan of ScottMadden, Inc., shows Valley to be a small public utility relative to his comparison group.

Q. As a small privately held utility, does Valley face any unique financial challenges?

A. Yes, it does. As Mr. D'Ascendis and Mr. Kucan explain, small utilities face increased financial and business risks.

Q. Mr. Rogers, can you provide an example of a risk faced by smaller utilities that larger utilities may not face?

A. Yes. As discussed by Mr. D'Ascendis and Mr. Kucan, smaller utilities are at greater risk to experience adverse financial impacts from a single customer leaving the system (either by plant closure or by switching to alternate fuel). Currently, Valley's three largest customers represent nearly 30% of distribution revenues per year. In addition, our five largest customers represent approximately 32% of our annual distribution margins, and three of the five have dual-fuel capabilities.

Q. Is Valley at risk to lose other customers?

A. Yes. In addition to the largest customers, many of our other customers have access to potential alternatives to natural gas service, including propane, fuel oil, wood and electric.

Q. How do you think the Commission should address the additional risks faced by small utilities?

A. I believe the Commission should address this risk through an appropriate overall return on distribution rates, including a size adjustment. Additionally, the

Commission should adopt the recommendations of Mr. D'Ascendis and Mr. Kucan for a market-reflective return on equity and a management performance adjustment.

Q What are the bases for the performance adjustments proposed by Mr. D'Ascendis and Mr. Kucan?

A. Mr. D'Ascendis' and Mr. Kucan's testimony cites to Section 523 of the Public Utility Code, 52 Pa. Code § 523, which sets forth the Commission's guidelines for performance adjustments. I am advised by counsel that the Public Utility Code identifies several criteria to be considered in assessing the performance of a fixed utility for purposes of a performance factor adjustment, including consideration of any relevant and material evidence of efficiency, effectiveness, and adequacy of service. The Commission should consider Valley's operations as supportive of the proposed performance adjustment, including the following.

- **Main replacements.** Valley has replaced all cast iron, bare-steel and the majority of vintage plastic mains without assessing a Distribution System Improvement Charge on its customers.
- **Low customer complaints.** Valley has also demonstrated exceptional customer service, as evidenced by the Company's record of no formal or informal complaints filed with the PUC over the prior 3 years.
- **Emergency Response**. For the period 2022 – 2024, Valley has responded to 98.77% of emergency calls in 60 minutes or less.
- **Favorable customer feedback.** Over the same three-year period from 2022-2024, over 97% of customers surveyed as part of Valley's annual Customer Contact Survey responded that they are "Very Satisfied" with

Valley's overall quality of service. The "Very Satisfied" election is the highest ranking on the survey, which is conducted by Valley, consistent using a form developed by the Commission's Bureau of Consumer Services, and provided annually to the Commission pursuant to 52 Pa. Code § 62.35.

- **Technology adoption: Smarthub use.** Valley has adopted Smarthub as an option for customers to manage bills electronically, analyze consumption, and conduct other business with the Company using their smartphone or other device. To date, 2,440 of Valley's customers use Smarthub and benefit from the convenience of this resource.
- **PIPE Grant for East Athens Expansion.** To reduce customer costs for a significant main extension project, the Company applied for grant funding from the Pennsylvania Department of Community and Economic Development's ("DCED") Pipeline Investment Program ("PIPE"). DCED approved the application and awarded an $850,000 PIPE grant for the project. The PUC Chairman noted the impact of this grant in a public statement, commending the Company on its "practical commitment to extending natural gas service" and specifically stating "I am pleased to see Valley utilize PIPE grant funds."
- **Low Lost and Unaccounted For Gas.** Valley's maintenance and replacement of gas infrastructure initiatives have resulted in an extremely low lost and unaccounted for percentage of -0.17%. There are two primary causes of lost gas — (1) leaks on mains and equipment that leak gas into the atmosphere.; and (2) meter inaccuracies. As explained by Mr.

Chapman, Valley proactively addresses both issues. At a $4 per Mcf gas cost, each 0.5% improvement in the lost and unaccounted for percentage saves our supplier of last resort customers $17,774 per year.

VALLEY STAFFING

Q. You previously mentioned that you are a C&T employee assigned to Valley. Can you please describe the employment structure at Valley?

A. C&T is both a holding company and a management services firm. Based on Valley's indications of need and preferred person to serve in each position, C&T provides the employees to fill all of Valley's employee positions. This includes management, administrative, customer support, and operational employees. In addition, C&T provides support services for activities that may not justify Valley employing its own full or part-time employee. Melissa Sullivan, Chief Financial Officer of C&T, will provide additional details regarding these shared services and how Valley compensates C&T for access to the services.

In total, Valley has 29 employees with two open positions that are in the process of being filled. This represents a significant increase from 2010, when Valley had 24 employees.

Q. Has Valley taken steps to determine whether the current workforce is appropriate for the current expectations in the gas industry?

A. Yes. We recently identified two full-time positions that will be changing to seasonal in late 2025. We have also added a leak survey technician position in 2025. This will enable us to increase the frequency of leak surveys, moving to a 3-year cycle rather than our historic 5-year cycle for residential areas, and leak

surveying Aldyl-A vintage plastic pipelines and steel tubing services on an annual basis. Mr. Gorman has made appropriate adjustments to the FPFTY to incorporate these changes.

Q. Has Valley examined the competitiveness of its wage and salary plan?

A. Yes. In 2024, we undertook a comprehensive review of our salaries in conjunction with the other operating companies in the C&T Enterprises corporate family. We compared the responsibilities, work experience, educational requirements and leadership responsibility for over 105 positions across the operating companies and the C&T Shared Services functions. We engaged a consultant to review salary data from various sources to develop salary ranges for various employee grades, keeping similar functions within the same grade, where feasible.

Q. Did Valley adjust salaries as a result of that review?

A. We identified a handful of positions that needed to be adjusted upward to reflect the current employment conditions. We began making those adjustments in early 2025, with a two-year phase-in (2025 and 2026). Ms. Beale provides an exhibit that calculates the net expense impacts of the Wage & Salary study and other anticipated staffing changes.

Our employees will also continue to receive annual salary adjustments as approved by the C&T Board of Directors, as well as any merit-based adjustments. Finally, the consultant will update the survey annually to confirm that our salary ranges for each grade in the plan remain appropriate. If necessary, we may adjust individual (or groups of) employees based on that annual update. Ms. Sullivan discusses the projected annual base salary adjustments and benefits costs.

Q. Why is it important to maintain competitive salary and benefits offerings?

A. Natural gas utility workers must possess specialized knowledge and skills. We need to attract quality applicants and then often must provide training for the individual to become fully competent in their job. Some of the positions require qualification tests and other certifications. Once Valley attracts the candidate, we invest our time and resources to help that worker enhance their skills. This benefits our customers through excellent customer service and through reliable maintenance and operation of the natural gas system. Competitive salary and benefits offerings help us to attract and retain our workforce, and to meet the customers' needs.

CUSTOMER SERVICE SCHEDULE CHANGES

Q. Does Valley anticipate any significant changes in service schedule for any customers?

A. Yes. One of our larger customers has requested to move to Rate Schedule I, as a transportation customer. In 2024 and the beginning of 2025, they were served on Rate Schedule IS-Interruptible Service and SI-Small Industrial. Mr. Gorman has reflected this change in his analysis by increasing the volume delivered under Rate Schedule I and decreasing the volumes under the two rate schedules. We also are proposing some changes to the rate design for Rate Schedule I.

Q. Please explain the changes to Rate Schedule I.

A. We are proposing to add a monthly customer charge to make the rate design consistent with other classes. Also, we are proposing to simplify the rate design by

decreasing the number of rate blocks for the commodity-based portion of the rate from the current three blocks to two blocks for the new rate.

TARIFF CHANGES

Q. Please explain Valley's proposed tariff rule changes.

A. We propose to modify Tariff Rules 4 and 6.

In Tariff Rule 4, we are adding a new section to address Excess Flow Valves (EFVs). This section requires the Company to include EFVs in new or replacement installations at our cost, consistent with Federal safety regulations. Those standards allow limited exceptions that would apply to the new rule. In addition, a customer with an existing installation can request and pay for an EVF.

In Tariff Rule 6, we are clarifying the customer's responsibility to pay for any costs or damages if they (or a third party on their behalf) tamper with our equipment.

Q. Does this complete your testimony?

A. Yes.

Valley Statement No. 4

BEFORE
THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	**:**	
	:	
v.	**:**	**Docket No. R-2025-_____**
	:	
Valley Energy, Inc.	**:**	

EXHIBIT

OF

EDWARD E. ROGERS

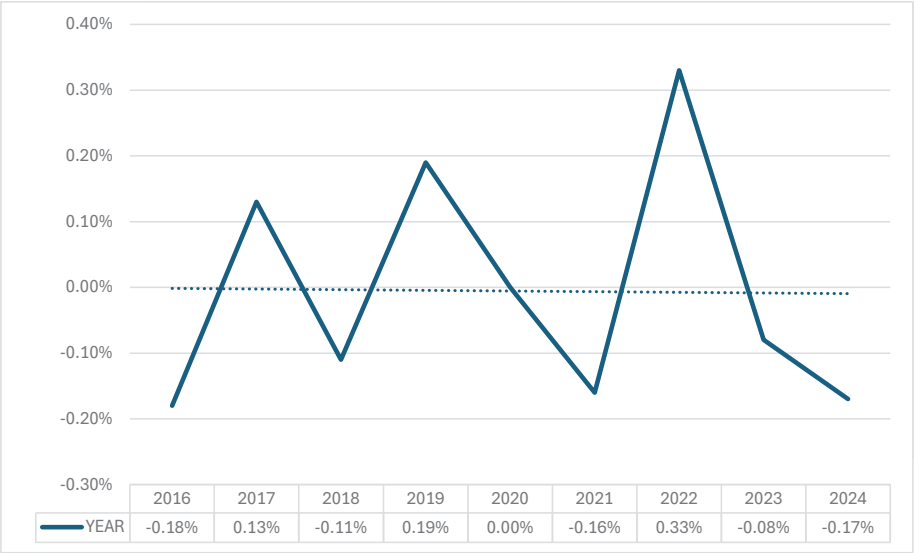
ON BEHALF OF

VALLEY ENERGY, INC.

APRIL 30, 2025

VALLEY ENERGY HISTORIC LOST AND UNACCOUNTED FOR GAS

YEAR	%	Average
2016	-0.18%	-0.01%
2017	0.13%	-0.01%
2018	-0.11%	-0.01%
2019	0.19%	-0.01%
2020	0.00%	-0.01%
2021	-0.16%	-0.01%
2022	0.33%	-0.01%
2023	-0.08%	-0.01%
2024	-0.17%	-0.01%
average	-0.01%	



Valley Statement No. 4R

BEFORE
THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	**:**	
	:	
v.	**:**	**Docket No. R-2025-3054393**
	:	
Valley Energy, Inc.	**:**	

REBUTTAL TESTIMONY AND EXHIBITS

OF

EDWARD E. ROGERS

ON BEHALF OF

VALLEY ENERGY, INC.

AUGUST 13, 2025

BEFORE
THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	**Docket No. R-2025-3054393**
	:	
Valley Energy, Inc.	:	

REBUTTAL TESTIMONY OF EDWARD E. ROGERS ON BEHALF OF VALLEY ENERGY, INC.

Q. Please state your name and business address.

A. My name is Edward E. Rogers. My business address is 523 Keystone Avenue, Sayre, Pennsylvania.

Q. Are you the same Edward E. Rogers who previously submitted Direct Testimony in this proceeding on behalf of Valley Energy, Inc. ("Valley")?

A. Yes. Terms defined in my direct testimony have the same meaning in this rebuttal testimony.

Q. What is the purpose of your testimony today?

A. The purpose of my testimony is to rebut the testimony of the following witnesses' direct testimony:

- Office of Consumer Advocate ("OCA") Witness Walters, Office of Small Business Advocate ("OSBA") Witness Farr and Bureau of Investigation and Enforcement ("I&E") Witness Patel regarding recommended Return on Equity ("ROE") allowances, including their proposals to deny the Company's proposed size and performance adjustments.

- OCA Witness Deupree regarding his recommendation to reject or reduce the Company's requested increase for the customer charge.
- OCA Witness Wise regarding her proposed elimination of processing fees for debit and credit card payments.
- OCA Witness Meyer regarding his proposed adjustments to the Company's payroll expenses and account 880 (Other Distribution Expenses).
- I&E Witness Wilson regarding her proposed adjustments to the Company's operations and maintenance expenses.

RETURN ON EQUITY

Q. Please summarize the parties' positions regarding an appropriate ROE for Valley (OCA Statement No. 2 at 3; OSBA Statement No. 1 at 4; I&E Statement No. 2 at 7).

A. OCA Witness Mr. Walters recommends an ROE of 9.5%; OSBA Witness Mr. Farr recommends an ROE of 10.15%; and I&E Witness Mr. Patel recommends an ROE of 10.51%.

Q. Do you have any initial comments regarding the OCA, OSBA and I&E recommendations?

A. Yes. The parties oppose the Company's proposed size and performance adjustment when arriving at their recommended ROE (OCA Statement No. 2 at 78-82; OSBA Statement No. 1 at 6-9; I&E Statement No. 2 at 48-59).

Q. Do you have any further comments with regard to the size and performance adjustments?

A. Mr. D'Ascendis' Rebuttal Testimony provides the primary response to OCA, OSBA and I&E on these adjustments. My testimony supplements Mr. D'Ascendis' response.

Regarding the performance adjustment, Mr. Walters, Mr. Farr and Mr. Patel inappropriately accuse the Company of seeking additional returns for complying with its mandatory obligations. These arguments are directly contradicted by my Direct Testimony, where I review several initiatives and accomplishments that reflect Valley's commitment to exceeding performance standards, not merely meeting them. For example, Valley was under no obligation to offer Smarthub online account access to its customers, which is an option for customers to manage bills electronically, analyze consumption, and conduct other business with the Company using their smartphone or other device. Similarly, Valley proactively replaced 100% of its cast iron and bare steel mains years before larger Natural Gas Distribution Companies ("NGDCs") implemented Distribution System Improvement Charges ("DSICs") for their replacement programs, which is illustrative of the Company's effective management and commitment to reliability and customer service. The Company is now focused on replacing leak prone Aldyl-A vintage plastic pipelines and service lines, which we project to have fully replaced within 3 to 5 years. Our proactive initiatives to maintain and replace gas infrastructure serveto significantly reduce the lost and unaccounted for gas to levels that are far below other NGDCs. Exhibit__(ER-1R) compares our lost and

unaccounted gas percentage to other Pennsylvania utilities. Proactively managing our lost and accounted for gas percentage saves our customers money on every mcf of gas that they use and is better for the environment.

Additionally, our outstanding emergency response, low customer complaints rate and high favorable customer feedback, as well as Valley's low termination rate should be considered in awarding an upward performance adjustment. The Company's 2.5% residential termination rate is considerably lower compared to the larger NGDC's average rate of 4.5% reflected in the Pennsylvania Public Utility Commission's ("Commission" or "PUC") 2023 Universal Service Programs & Collections Performance Report – September 2024.

We quantified the value to our customers from operational efficiencies as part of our discovery responses in this proceeding. Based on previous improvements and continued efficiencies, the Company has been able to provide overall cost savings in excess of $452K or $61 annually per customer (OCA-VI-24 Attachment A – Cost savings.xlsx). A copy of this response is attached as Exhibit__(ER-2R).

A performance adjustment mechanism is available under Pennsylvania statute, and I believe Valley has earned it based on the Company's achievements and initiatives outlined in my Direct Testimony.

Q. Do you have any comments regarding the size adjustment?

A. With respect to Valley's proposed size adjustment, my Direct Testimony explains the real risk of losing one or more of our largest customers who have access to potential alternatives to natural gas service. Additionally, the Commission has previously approved a size adjustment for small utilities, including Valley.

Contrary to I&E Witness Patel's characterization of the Commission's holding regarding the outcome of Citizens' and Valleys' request for a size adjustment in its 2019 rate base case proceeding, the Commission specifically considered the size of the company. In doing so, the Commission approved an upward adjustment to the cost of equity by allowing for one standard deviation above the average of the mean and median proxy group ROE of the Company's DCF analysis.[1] In doing so, the Commission specifically recognized Mr. D'Ascendis' record evidence of a general inverse relationship between size and risk, such that smaller companies like Citizens' and Valley face greater risk. Consistent with the Commission's affirmative finding of size risk in the 2019 Valley and Citizens' decisions, Company Witness D'Ascendis recommended a size premium of 1.00% for Valley. This recommendation should be approved by the Commission.

Q. Have the considerations on which the Commission's size and performance adjustment determinations were based changed since the 2019 rate case?

A. No. Valley is still a very small utility. As Mr. D'Ascendis testified, it still requires a higher return to provide the resources to handle significant events that affect revenues, costs, plant and earnings. As stated above, Valley still performs very well

[1] *Pa. PUC v. Citizens Electric Company of Lewisburg, PA,* Docket No. R-2019-3008212 (Order Entered April 29, 2020). See generally Disposition of Cost of Common Equity at 103-104 and *Pa. PUC v. Valley Energy, Inc.,* Docket No. R-2019-3008209 (Order Entered April 27, 2020). See generally Disposition of Rate of Return of Common Equity at 124-125.

on the measures of management effectiveness discussed in the Commission's Order in the 2019 rate case.

Q. Is it important that the Commission be consistent in applying the criteria it uses to determine ROE?

A. Yes, it is critically important, especially for business and financial planning. When we are making investment decisions and planning for future financial activities, including the timing of rate cases, it is important for us to be able to use consistent assumptions. Large changes in regulatory treatment on the size adjustment would complicate our planning and create additional financial risk for Valley.

CUSTOMER CHARGE

Q. Please describe OCA Witness Deupree's analysis of an appropriate customer charge (OCA Statement No. 3 at 3-10).

A. Mr. Deupree relies on current residential and small commercial customer charges of other regional gas utility companies to justify the denial of an increase or to limit the increase to no more than the overall system average increase of the peer group of regional gas utilities.

Q. Does Mr. Deupree's analysis explore the customer charges of other Pennsylvania gas utilities which rates are set by the Commission for comparison with Company?

A. No. Mr. Deupree relies on non-Pennsylvania gas utilities to justify his recommendation. The appropriate comparison group is the other Pennsylvania natural gas distribution companies of similar or larger size. Exhibit__(ER-3R) provides the customer charges for the relevant Pennsylvania utilities as reflected in

the Commission's most recent rate comparison report. The exhibit also includes the charges for Corning Natural Gas, which is just across the Pennsylvania-New York border. Compared to these gas utility companies, the Company's residential and small commercial customer charges are lower than all the companies surveyed. The requested customer charge is not unreasonable as compared to other gas utilities in Pennsylvania.

OTHER PROPOSED ADJUSTMENTS

Q. Mr. Rogers, will you be the only respondent addressing adjustments to expenses and rate base proposed by the OCA and I&E Witnesses in this proceeding?

A. No. Mr. Gorman and Ms. Beale will also address the proposed expense adjustments. To the extent I do not address a proposed adjustment in my testimony, such omission does not represent my acceptance of, or agreement with, the proposed adjustment.

PAYROLL EXPENSE

Q. Did OCA Witness Meyer propose adjustments to Valley's Payroll Expense (OCA Statement No. 1 at 5-7)?

A. Yes. Mr. Meyer proposed an adjustment of $19,892 to the Company's Fully Projected Future Test Year ("FPFTY") payroll expenses based on his recommendation to apply a 4% payroll increase for Future Test Year ("FTY") 2025 and FPFTY 2026.

Q. Did you find the adjustments to Valley's Payroll Expense proposed by OCA to be generally reasonable?

A. No. Mr. Meyer's proposed adjustment was based on "experience" and not the multiple detailed discovery responses that support the Payroll Expense projections for the FTY and FPFTY. Historic Test Year ("HTY") 2024 preceded implementation of the C&T Wage and Salary Study, which identified 22 of the 31 positions (71%) needing market adjustments. The C&T Wage and Salary implementation plan was structured to increase wages over a two-year period, starting in January 2025, with final adjustments being made in January 2026. We also must account for salary increases for performance or competency progression within the payroll grade. All of this was summarized in our Exhibit__(JB-3).

In support of the exhibit, Valley provided the OCA with the ability to review the detailed spreadsheet that includes all Valley positions, including the adjustments. Adjusting for the base compensation increases, as the OCA has done, understates the projected expenses and ignores the evidence that we provided in support of our FTY and FPFTY labor expenses.

OFFICE SUPPLIES & EXPENSE

Q. Did I&E Witness Wilson propose adjustments to Valley's Office Supplies & Expense (I&E Statement No. 1 at 16-18)?

A. Yes. Ms. Wilson proposed an adjustment of $17,126 to the Company's FPFTY Office Supplies & Expense based on averaging the most recent three years and denying a 3% inflation adjustment.

Q. Did you find the adjustments to Valley's Office Supplies & Expense proposed by I&E reasonable?

A. No. Averaging the most recent three years does not take into account the lower expense anomaly that occurred in 2024 due to external pressures on cash flows, as a result of unexpected contractor expenses and material costs, which resulted in reductions in travel and training expenses. Like many businesses, when we are faced with unexpected cost increases or lower than expected revenues, we may reduce items such as business travel and training in the year to maintain our budget. 2024 was a year when we took those temporary cost reduction measures; however, reduced travel and training is not sustainable if we want to keep our workforce competent. This expense account increased by 20% from 2022 to 2023 and an annual increase of 3.5% from 2023 to FTY 2025. Based on 2025 YTD expenses of $42,445, the annualized expense for FTY 2025 would be $84,890, higher than the amount included in the filing. Finally, a 3% inflation adjustment is not unreasonable based on the percentage increases in response I&E-RE-10-D.

ACCOUNT 880 (Other Distribution Expenses)

Q. Did OCA Witness Meyer propose adjustments to Account 880 (Other Distribution Expenses), (OCA Statement No. 1 at 7-10)

A. Yes. Mr. Meyer proposed an adjustment of $35,452 to the Company's FPFTY Other Distribution Expense.

Q. Does the proposed adjustment accurately reflect the basis for the Company's FPFTY expense for this account?

A. No. Historical expense levels do not reflect the actual expenses that are now attributable to this account for the FTY and FPFTY.

Q. What has changed to make historic experience non-reflective of changes to this account going forward?

A. First, we have actually transferred accounting for our ESRI subscription and certain United States Department of Transportation/PHMSA training from this account into Account 930.20 starting in 2025.

Second, beginning in 2024, we added an Energy WorldNet subscription, which is a computer-based training and evaluation platform for the Company's Operator Qualification (OQ) program.

Third, we implemented a new OQ platform starting in 2024 that involved significant labor hours in order to qualify all of the relevant employees in our workforce to the new OQ testing and evaluation requirements, which significantly increased the expense for this account. Going forward, we are implementing a staggered three-year cycle for recertification activities for our operators. This decreased the labor expenses for Account 880 from 2024 to FTY 2025. From the FTY to the FPFTY, we are continuing the three-year cycle with the 2nd cohort; however, the labor expense (and overheads) will increase along with the labor and overheads in other accounts. Exhibit__(ER-4R) provides a detailed breakdown of the costs by line item.

Q. Was Account 880 impacted by the data error that Mr. Gorman identified during the discovery phase?

A. Yes. Exhibit__(HSG-1), Schedule C1-1 labor entry for account 880 was inadvertently included for account 879. The correct labor entry for account 880 should be $41,265 rather than $0. Please refer to Mr. Gorman's revised Schedule C1-1(R) for supporting data claim.

Q. Do you have any final comments regarding Mr. Meyer's adjustment?

A. Mr. Meyer's adjustment assumes that the increase from FTY 2025 to FPFTY 2026 is non-labor expenses; however, as shown on Exhibit__(ER-5R), the majority of the expenses for this account are labor and labor overheads.

CUSTOMER PAYMENT FEES

Q. Did OCA Witness Wise propose eliminating the processing fees for debit and credit card payments, (OCA Statement No. 4 at 2-7)?

A. Yes. Ms. Wise proposes to eliminate the $3.95 fee for customers paying their bills via credit or debit card.

Q. Do you agree with eliminating the $3.95 fee for customers to pay via credit card or debit card?

A. No. While I agree that electronic and paperless transactions are becoming more common, I don't agree with her statements that "accessing an additional fee is contrary to the principles of reasonable utility service," or "Customers pay for household goods via credit and debit cards without being assessed an additional fee," or "The policy of charging a fee is quite harmful to lower income customers who may be unbanked and rely on pre-purchase debit cards to make payments."

As for reasonable utility service, the customer currently has many options to pay, which are much cheaper on a transactional basis compared to the current fee associated with debit or credit card payments. Also, consumers often get incentives from the credit card company to pay by card. Is it reasonable for a fixed-income customer who still uses checks and drops their payment off at the office to pay higher rates so a more affluent customer can get airline miles for their next vacation?

While some household purchases may not involve a fee, there are many that do. A local sewer authority charges a fee when paying via debit or with credit card, as well as other retail offerings.

For lower income customers who may be unbanked, the Company has many options for these customers to pay: at our office and at three strategically located banks in our service territory that will accept cash payments without a fee.

If the fee is eliminated, usage will certainly increase and the OCA adjustment based on the fees collected in 2024 will be insufficient to account for this change. A slightly larger (15,000 customers) natural gas utility in New York saw a dramatic increase in the use of online payments when they discontinued the practice of charging a fee for this service. The number of online payments for 2021 (30,063) compared to 2023 (45,913) increased by 53% over a two-year timeframe, post COVID. Exhibit__(ER-6R) includes this information.

Q. If the Commission requires Valley to assume the credit card fees, is the OCA's addition to the revenue requirement sufficient to compensate Valley for these projected costs?

A. Due to the evidence that I just discussed, the OCA's proposal is not sufficient. If it is accepted despite our opposition, then the Commission should allow Valley to track and defer any costs that exceed the OCA's projection for recovery in our next rate case.

Q. Does this complete your Rebuttal Testimony?

A. Yes

Valley Statement No. 4R

BEFORE
THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	**:**	
	:	
v.	**:**	**Docket No. R-2025-3054393**
	:	
Valley Energy, Inc.	**:**	

EXHIBITS

OF

EDWARD E. ROGERS

ON BEHALF OF

VALLEY ENERGY, INC.

AUGUST 13, 2025

EXHIBIT__(ER-1R)

Valley Energy, Inc. (PA)

Lost and Unccounted For Gas History

Data Shown is as per the UFG Annual Reports provided on the Pennsylvania Public Utility Commission's website

Company	12 month period ending August 31, 2020	12 month period ending August 31, 2021	12 month period ending August 31, 2022	12 month period ending August 31, 2023	12 month period ending August 31, 2024
Columbia Gas of PA Inc.	0.87%	0.42%	1.23%	0.86%	0.99%
Leatherstocking Gas Co.	2.66%	2.36%	3.09%	3.72%	2.60%
National Fuel Gas Distribution Corp.	-0.17%	-0.22%	-0.29%	-0.81%	-0.39%
PECO Energy Co.	1.51%	0.55%	2.72%	1.00%	1.37%
Peoples Natural Gas Co. LLC	2.82%	1.63%	2.19%	2.69%	3.05%
Peoples Gas Company LLC	2.75%	3.00%	Filed Combined UFG Report with Peoples Natural Gas Co. LLC		
Philadephia Gas Works	1.30%	0.87%	0.89%	0.89%	1.17%
Pike County Light & Power	1.96%	2.53%	-5.78%	1.32%	2.76%
UGI Utilities Inc. - Gas Division	0.34%	0.12%	Data unavailable on PA PUC Website	0.43%	0.71%
Valley Energy, Inc	-0.16%	0.33%	-0.19%	-0.08%	-0.17%

VALLEY ENERGY, INC.
DOCKET NO. R-2025-3054393

OCA-VI-24

Of the benefits described on Valley Energy, Inc. Statement 4, page 9 line 13-23, page 10 line 1-23, page 11 line 1-3 of Mr. Rodgers testimony, please provide in detail (live excel format with formulas intact) the cost savings the company has experience through operational efficiencies.

Response Provided By:
Edward E. Rogers, President and Chief Executive Officer, Valley Energy, Inc.

Date: June 16, 2025

Response:

The Company has provided cost savings for our customers over the past and continuing projected years by operating efficiently while still providing a safe and reliable service cost effectively. Based on previous improvements and continued efficiencies, the Company has been able to provide overall cost savings in excess of $452K or $61 annually per customer.

In regard to providing efficient customer service, the Company has: (1) reduced costs associated with errors or rework, (2) reduced support needed, leading to lower labor costs and reduced need for resources, and (3) increased efficiency by providing self-service options via the Company's updated website, based on a demonstrated exceptional customer survey, as evidenced by the Company's lack of formal or informal complaints filed and customer survey results (OCA-III-20 Attachment B).

Examples of cost savings associated with operational efficiencies:

A. The company has eliminated all cast iron, bare steel and the majority of vintage plastic mains within its service territory, all without assessing a Distribution System Improvement Charge and incurring interest expenses for long-term debt. Another cost saving measure attributed to eliminations of these assets is the decrease in the size of the construction department. Refer to OCA-VI-24 Attachment A – Cost Savings.

B. As part of an internal review of projected work processes and evaluation of required employee complement, there were two positions that were re-classified from full-time to seasonally, resulting in reduced employee labor costs and overheads. Refer to OCA-VI-24 Attachment A – Cost Savings.

C. The awarding of the PIPE Grant for the E. Athens project resulted in overall savings, thus reducing the monthly surcharge from $127.15 per month to $29.20 per month.

D. The Company has an extremely low, lost and unaccounted for gas percentage (-0.17%), for the most recent reporting period. The Company’s percentage is significantly lower than the allowed 3% distribution loss as established in docket No. L-2021-2294746. Refer to OCA-VI-24 Attachment A – Cost Savings for estimated annual cost savings based on low lost

and accounted for gas percentages, which is based on overall system improvements, efficiency in managing leak repairs and accelerated meter testing program.

	Estimated - Current Annual Cost Savings	Note
A. Main Replacements		
When the Company did have cast iron, bare-steel and incrementally more vintage plastic mains in system, there were six construction department employees employed by the Company, where two employees were predominantly tasked with repairing leaks on these types of facilities. With all cast iron, bare-steel and the majority of vintage plastic mains replaced, the construction department has shrank in size, from six to four.	$187,491	Two employees - wages, benefits and taxes
	$40,712	Transportation and equipment costs associated with two employees
	$228,203	
B. Re-classification of two positions from full time to seasonal	$117,836	
Meter Reader position (FTE)	$88,366	annual salary with benefits
Meter Reader position (Seasonal)	$31,503	annual salary + pension/401K
	$56,863	annual savings
Regulator Shop position (FTE)	$99,879	annual salary with benefits
Regulator Shop position (Seasonal)	$38,906	annual salary + pension/401K
	$60,973	annual savings
	Savings per Customer	
C. PIPE Grant for East Athens Expansion		
Additional costs for the these customers in the E. Athens area if the PIPE grant was not approved.	$11,754	overall
	$97.95	monthly
	Savings per Customer	
D. Low Lost and Unaccounted For Gas		
Estimated cost based on $4 per Mcf gas cost, where each 0.5% improvement results in $17,774 in savings.	$106,644	overall
Estimated savings per customer based on $4 per Mcf gas cost, where each 0.5% improvement results in $17,774 in savings, with an allowed 3% gas lost percentage	$14.52	annual

EXHIBIT__(ER-3R)

Valley Energy, Inc. (PA)

Customer Charge Comparisons

Data Shown is as per the Pennsylvania Public Utility Commission
Rate Comparsion Report dated April 15, 2025 (unless otherwise noted)

Company	**Residential**	**Commercial**
Columbia Gas of PA Inc.	$17.25	$33.00
National Fuel Gas Distribution Corp.	$14.00	$27.00
PECO Energy Co.	$15.70	$36.38
Peoples Natural Gas Co. LLC	$16.80	$22.00
Philadephia Gas Works	$16.25	$27.65
UGI Utilities Inc. - Gas Division	$15.00	$27.38
Average	$15.83	$28.90
Corning Natural Gas Corporation *	$22.00	$33.29
Valley Energy, Inc. - At Present Rates	$12.35	$21.95
Valley Energy, Inc. - As per Filing**	$14.00	$25.00
Valley Energy, Inc. - Proposed Settlement		

* Corning Natural Gas Corporation rate data is as per Corning Natural Gas Corporation's Customer Tariff posted on their company website.

** Valley Energy Inc.'s proposed rate data is as per Valley Energy Inc.'s Rate Case Filing.

Account 880 - Operator Qualification **EXHIBIT__(ER-4R)**

	2023	2024	2025	2026
Labor (01)	$ -	$ 41,265	$ 20,603	$ 27,982
Transportation (02)	$ -	$ 201	$ 136	$ 140
C&T Ovhds (03)	$ -	$ 11,802	$ 5,319	$ 7,224
VE Ovhds (05)	$ -	$ 40,283	$ 19,851	$ 26,556
Expense (45)				
US DOT - PHMSA	$ 4,880	$ 5,813	$ -	
ESRI	$ 2,370	$ 10,062	$ -	
Misc	$ -	$ 190	$ 195	$ 201
Energy WorldNet	$ -	$ 5,089	$ 5,242	$ 5,399
Training Supplies	$ -	$ -	$ 3,090	$ 3,183
	$ 7,250	$ 114,706	$ 54,436	$ 70,685

2024

A new Operator Qualification (OQ) Program established late 2023 using the Energy WorldNet platform. To adequately track the increased expenses for the new OQ program, all OQ expenses were allocated to account 880, where previously they were allocated to a holding account and allocated based on labor hours.

2025 / 2026

Expenses for US DOT - PHMSA and ESRI were budgeted to account 930.20 for 2025 and 2026, going forward. Decrease in labor and corresponding overhead accounts in 2025 and 2026 is due to fewer labor hours as a result of averaging a portion of the OQ task requirements on a three year schedule.

Account 921.00

EXHIBIT__(ER-5R)

		2021	2022	2023	2024	2025	2026	
General Office Supplies	921.00	$ 12,121	$ 13,448	$ 11,885	$ 10,761	$ 12,054	$ 12,054	2025 / 2026 - based on 4-year average
Meals Expense	921.40	$ 2,511	$ 5,155	$ 7,894	$ 8,346	$ 9,132	$ 9,406	2025 - 2024 expense plus budgeted increase / 2026 - 3% inflation
Travel & Training	921.45	$ 18,285	$ 27,948	$ 38,885	$ 16,808	$ 40,834	$ 42,059	2024 - lower due to cash restraints / 2025 - budgeted expenses / 2026 - 3% inflation
Communication Equipment	921.50	$ 11,712	$ 15,524	$ 16,248	$ 20,560	$ 17,350	$ 17,871	2025 - decrease due to elimination one-time expenses / 2026 - 3% inflation
		$ 44,629	$ 62,075	$ 74,912	$ 56,475	$ 79,370	$ 81,390	
			39.09%	20.68%		5.95%	2.55%	

Corning Natural Gas

EXHIBIT__(ER-6R)

	actual	actual	actual	actual	actual	actual	actual	approved in rate case				
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
# of transactions	11,590	19,240	25,575	30,063	39,253	45,913						
% increase		66.01%	32.93%	17.55%	30.57%	16.97%						
*fees		$ 46,176	$ 52,242	not available	$ 66,288	$ 78,683	$ 98,344	$ 107,914	$ 114,872	$ 120,839	$ 125,556	$ 129,679
% increase						18.70%	24.99%	9.73%	6.45%	5.19%	3.90%	3.28%

eliminated fee

*fees - credit/debit varied by type of payment, not a single fee.

Valley Statement No. 5

BEFORE

THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	**:**	
	:	
v.	**:**	**Docket No. R-2025-_____**
	:	
Valley, Energy, Inc.	**:**	

DIRECT TESTIMONY

AND EXHIBITS

OF

JAMIE BEALE

ON BEHALF OF

VALLEY ENERGY, INC.

APRIL 30, 2025

BEFORE

THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	**:**	
	:	
v.	**:**	**Docket No. R-2025-_____**
	:	
Valley Energy, Inc.	**:**	

DIRECT TESTIMONY OF JAMIE BEALE
ON BEHALF OF VALLEY ENERGY, INC.

Q. Please state your name and business address.

A. My name is Jamie Beale and my business address is 523 Keystone Avenue, Sayre, Pennsylvania.

Q. By whom are you employed and in what capacity do you serve at Valley Energy, Inc. ("Valley")?

A. I am employed by C&T Enterprises, Inc. ("C&T"), and assigned to Valley as the Vice President of Finance and Treasurer.

Q. Please describe your duties in this capacity.

A. My duties are to organize, direct, and coordinate the financial department. I provide administrative direction for billing for gas service to consumers. I also advise the President & CEO of the financial aspects of the company, manage the financial record keeping, coordinate the budget, coordinate with computer services, and coordinate with consumer services. I am also responsible for coordinating credit discussions with Valley's wholesale natural gas suppliers.

Q. Please describe your educational and employment background.

A. I attended Mansfield University from 2005 to 2008 and graduated with a BS in Business Management. I worked for Guthrie Healthcare Systems and Evangelical Community Hospital prior to joining Valley Energy.

Q. What were your responsibilities with respect to this filing?

A. As the Vice President of Finance and Treasurer, I was responsible for coordinating with our auditors and Company witness Mr. Gorman to ensure that historic and test year expenses, taxes, revenues, sales and rate base were appropriately reflected. I was responsible for ensuring that the expense, plant and sales information provided to Mr. Gorman that is reflected in Exhibit __ (HSG-1) was correct.

Q. Have you previously testified before the Pennsylvania Public Utility Commission?

A. Yes. I provided Direct, Rebuttal and Oral Rejoinder testimony in Valley's 2019 rate case at Docket No. R-2019-3008209 and Direct and Rebuttal testimony in Valley's 2022 rate case at Docket No. R-2022-3032300.

VALLEY FINANCIAL INFORMATION

Q. Are Valley and its records regularly audited by a licensed accounting firm?

A. Yes. The accounting firm of FORVIS MAZARS, LLC audits the Company's financial records. They prepare an annual report of the Company operations and assist Company personnel on specific Pennsylvania Public Utility Commission ("PUC" or "Commission") filings, such as our State Tax Adjustment Surcharge filings. They also prepare our tax returns. A copy of our Annual Report for the year ended December 31, 2024, is attached as Exhibit__(JB-1). A copy of our most

recent STAS filing is attached as Exhibit__(JB-2). Copies of our most recent state income tax filings for Pennsylvania are included in Volume III of the filing as Valley Confidential Exhibit 3. Valley's New York filing is included in the C&T Consolidated Federal tax file that is included as Joint Confidential Exhibit 3.

Q. How did the Company develop the financial data provided to HSG Group?

A. The Historic Test Year ("HTY") data is based on actual experiences during the HTY ending December 31, 2024. The Future Test Year ("FTY") data is based largely on our operating budget for the year ending December 31, 2025, with updates for any known and measurable changes that we have identified between the date that budget was approved by our Board of Directors and April 2025 when we are submitting this filing. The Fully-Projected Future Test Year ("FPFTY") data is based on our projections for the year ending December 31, 2026.

Q. Please discuss the major expense categories for Valley.

A. Valley's expenses are budgeted and tracked in the following categories: (1) Labor & Overheads, including C&T Shared Services; (2) Transportation; (3) Materials & Supplies (4) Administrative & General; (5) Outside Services; (6) Uncollectibles; (7) Depreciation & Amortization; (8) Regulatory Fees; and (9) Taxes. Valley also reports by account, corresponding to the FERC chart of accounts. Each Operating and Maintenance account includes (as appropriate) costs for Labor, Overhead, Material and Transportation. The information provided to Mr. Gorman is by FERC account, with subaccounts for Labor, Overhead, Material and Transportation.

Q. What is the largest expense category?

A. Labor & Overheads constitute the largest expense item. This category includes our employees and the various benefits that we provide (health, dental, vision, retirement, etc.). To develop the projected 2026 costs for Labor & Overheads, we examined the wages and benefits for our employees. We also accounted for the position changes discussed in Mr. Rogers' testimony.

Q. Have you prepared an exhibit showing the impact of the salary changes and the position changes for the FTY and FPFTY?

A. Yes. Attached as Exhibit__(JB-3) is an analysis that supports that impact. The impact of these changes are distributed among the various FERC accounts that Mr. Gorman reflects in his analysis according to where the employee's time is booked (based on activities performed).

Ms. Sullivan's testimony discusses the 2025 and projected 2026 C&T base compensation adjustments and our projections for personnel insurance benefits cost changes. Ms. Sullivan also discusses the C&T Shared Services that are included in our Labor & Overheads for 2024, 2025 and 2026.

Q. Please discuss the Transportation projections.

A. This item reflects the costs of our vehicles and other equipment, including fuel and maintenance expenses. For 2025, we are projecting to add one vehicle and replace one with no new additions or replacements in 2026. Our expenses for Transportation also reflect our expected fuel purchases for vehicles and equipment.

Q. Is Valley projecting increased Materials and Supplies costs?

A. Yes. The costs of various materials and supplies for our business have continued to increase, consistent with general inflation of many items. Each expense account

was reviewed and projected known increases were included. Mr. Chapman will address the increases in our system materials.

Q. Please discuss the costs incurred by Valley for Administrative and General.

A. The items in this category include the general costs to heat, furnish and maintain our office space and warehouses. For 2025, we made an adjustment to the HTY expenses to include expenses that were previously allocated to Account 880.45 and for a new recuring expense for Environmental System Research Institute (ESRI) cloud services that will work with the Company's Geographic Information System (GIS).

Q. What costs are included in Outside Services?

A. Outside Services includes the charges by various vendors for their service. This includes attorneys, accountants, auditors, consultants, cleaning vendors and contractors.

Q. Could costs in the categories that you addressed above be capitalized rather than being expensed?

A. Yes. As part of this filing, we have made assumptions regarding the portion of Labor & Overheads, Transportation, Materials & Supplies and Administrative & General that will be capitalized rather than expensed. We have done this based on both historic experience and projected 2025 and 2026 capital projects.

Q. How does Valley apportion costs between the Pennsylvania and New York jurisdictions?

A. Valley Energy uses a four-factor allocation method to apportion costs between Pennsylvania and New York jurisdictions. The four factors are: operating expense

ratio, investment in plant ratio, average customer ratio, and payroll ratio. The 2024 allocation, which was used by Mr. Gorman, is attached to my testimony as Exhibit__(JB-6).

Q. How did Valley develop the Uncollectibles expenses?

A. Uncollectibles expense is based on historic experience.

Q. Please discuss the Depreciation and Amortization expense reflected in the filing.

A. Depreciation expense is developed by Mr. Gorman, Exhibit__(HSG-1), Schedule C3 and explained in his testimony.

Q. Finally, what Regulatory Fees and Taxes are reflected in the filing?

A. These are developed by Mr. Gorman, Exhibit__(HSG-1), Schedule C1-3, and explained in his testimony.

Q. Do you have any information regarding Valley's actual expenses during the FTY?

A. Yes. Attached as Exhibit__(JB-4) is a table showing the operating expenses for the HTY as contained in the filing in Schedule C1-1 of Exhibit__(HSG-1), as well as actual expenses booked as of March 31, 2025. Although there is some variation within particular categories and expenses, on the whole, our actual year 2025 expenses are tracking as we would expect at this point of the FTY. We will continue to update this Exhibit during the FTY to confirm that our projected expenses are accurate.

Q. Is it unusual for Valley's expenses by Account to vary from quarter to quarter during the year?

A. No. For many of our Accounts, our actual expenses vary quarter-to-quarter based on the activities that our workers and contractors are doing. Over the entire year, there can be some overall variation if more of our work is done on projects that are expensed rather than projects that are capitalized. Mr. Chapman will explain how the types of projects and focus of our workers may vary during the various quarters of the year. The expenses can also vary due to unexpected weather or other circumstances.

Q. Did the Company assist Mr. Gorman in the compilation of the plant account information included in Valley Exhibit HSG-1?

A. Yes. We provided detailed information to Mr. Gorman regarding the original cost, book depreciation reserve, depreciation rates and depreciation expenses on the Company's books. With the exception of minor prospective changes to depreciation assumptions that were justified in Valley's 2010 base rate filing and as explained below for this filing, the original cost and depreciation reserve reflect the amounts on NUI's books when C&T acquired the system on November 7, 2002, without any reflection of an "acquisition premium" or adjustment. We also provided data regarding the additions to utility plant that we anticipate will occur through 2026. Mr. Gorman's Exhibit__(HSG-1), Schedule C3 shows the net increase in the original cost of our utility plant in service from the HTY to the FPFTY.

Q. What depreciation changes is the Company proposing for this filing?

A. We are proposing to reduce the useful life of our computer equipment and software from 5 years to 3 years. This is consistent with the replacement cycle for IT

equipment that we follow, and is also consistent with the warranty period on new equipment. We are asking for this change to apply prospectively after this case; Mr. Gorman has not included the adjusted depreciation assumption in his calculations.

Q. Do you have any information regarding Valley's actual plant during the FTY?

A. Yes. Attached as Exhibit__(JB-5) is a table showing the original cost of our plant in service for the HTY as contained in the filing, as well as the costs booked as of March 31, 2025. Although there is some variation within particular categories, again, on the whole our actual year 2025 capital additions are consistent with our expectations for this time of the year. As previously discussed and addressed in more detail by Mr. Chapman, some variation can be expected because we undertake capital improvement projects primarily during the warmer months of the year (when the ground has thawed). We also will update this Exhibit during the course of this proceeding.

VALLEY ENERGY FINANCING ACTIVITIES

Q. Please explain the Company's financing arrangements.

A. Valley's primary source of financing is its parent company, C&T Enterprises, Inc., which obtains long-term loans, lines of credit and letters of credit on Valley's behalf through the National Cooperative Servicing Corporation ("NCSC"). Each long-term loan is supported by a Securities Certificate approved by the Commission. Ms. Sullivan provides an exhibit with details of each loan. We also

have access to a short-term line of credit through C&T, as described by Ms. Sullivan.

Finally, we maintain a local banking relationship with C&N Bank.

AFFILIATE CHARGES

Q. Does Valley have any affiliate charges in the HTY, FTY or FPFTY in addition to the ones with C&T that are discussed by Ms. Sullivan?

A. No.

Q. Does this conclude your testimony at this time?

A. Yes.

Valley Statement No. 5

BEFORE

THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	**:**	
	:	
v.	**:**	**Docket No. R-2025-_____**
	:	
Valley, Energy, Inc.	**:**	

EXHIBITS

OF

JAMIE BEALE

ON BEHALF OF

VALLEY ENERGY, INC.

APRIL 30, 2025

Valley Energy, Inc.

Independent Auditor's Report, Financial Statements and Supplementary Information

December 31, 2024 and 2023

Valley Energy, Inc.
Contents
December 31, 2024 and 2023

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Independent Auditor's Report

Board of Directors
Valley Energy, Inc.
Sayre, Pennsylvania

Opinion

We have audited the financial statements of Valley Energy, Inc. (Company), which comprise the balance sheets as of December 31, 2024 and 2023, and the related statements of income, stockholder's equity, and cash flows for the years then ended, and the related notes to the financial statements.

In our opinion, the accompanying financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2024 and 2023, and the results of its operations and its cash flows for the years then ended in accordance with accounting principles generally accepted in the United States of America.

Basis for Opinion

We conducted our audits in accordance with auditing standards generally accepted in the United States of America (GAAS). Our responsibilities under those standards are further described in the "Auditor's Responsibilities for the Audit of the Financial Statements" section of our report. We are required to be independent of the Company and to meet our other ethical responsibilities, in accordance with the relevant ethical requirements relating to our audits. We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Responsibilities of Management for the Financial Statements

Management is responsible for the preparation and fair presentation of the financial statements in accordance with accounting principles generally accepted in the United States of America, and for the design, implementation, and maintenance of internal control relevant to the preparation and fair presentation of financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the financial statements, management is required to evaluate whether there are conditions or events, considered in the aggregate, that raise substantial doubt about the Company's ability to continue as a going concern within one year after the date that these financial statements are available to be issued.

Auditor's Responsibilities for the Audit of the Financial Statements

Our objectives are to obtain reasonable assurance about whether the financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditor's report that includes our opinion. Reasonable assurance is a high level of assurance but is not absolute assurance and therefore is not a guarantee that an audit conducted in accordance with GAAS will always detect a material misstatement when it exists. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control. Misstatements are considered material if there is a substantial likelihood that, individually or in the aggregate, they would influence the judgment made by a reasonable user based on the financial statements.

In performing an audit in accordance with GAAS, we:

- Exercise professional judgment and maintain professional skepticism throughout the audit.
- Identify and assess the risks of material misstatement of the financial statements, whether due to fraud or error, and design and perform audit procedures responsive to those risks. Such procedures include examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements.
- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control. Accordingly, no such opinion is expressed.
- Evaluate the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluate the overall presentation of the financial statements.
- Conclude whether, in our judgment, there are conditions or events, considered in the aggregate, that raise substantial doubt about the Company's ability to continue as a going concern for a reasonable period of time.

We are required to communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit, significant audit findings, and certain internal control-related matters that we identified during the audit.

Supplementary Information

Our audits were conducted for the purpose of forming an opinion on the financial statements that collectively comprise the Company's basic financial statements. The supplementary information listed in the table of contents is presented for purposes of additional analysis and is not a required part of the basic financial statements. Such information is the responsibility of management and was derived from and relates directly to the underlying accounting and other records used to prepare the basic financial statements.

The information has been subjected to the auditing procedures applied in the audit of the basic financial statements and certain additional procedures, including comparing and reconciling such information directly to the underlying accounting and other records used to prepare the basic financial statements or to the basic financial statement themselves, and other additional procedures in accordance with auditing standards generally accepted in the United States of America. In our opinion, the information is fairly stated in all material respects in relation to the basic financial statements as a whole.

Forvis Mazars, LLP

St. Louis, Missouri
March 12, 2025

Valley Energy, Inc.
Balance Sheets
December 31, 2024 and 2023

	2024	2023
ASSETS		
Utility Plant, at Cost		
Gas plant in service	$ 56,695,793	$ 53,390,499
Accumulated depreciation	(29,002,827)	(27,581,623)
	27,692,966	25,808,876
Construction work in progress	277,959	101,383
Net utility plant	27,970,925	25,910,259
Regulatory asset	80,613	148,308
Current Assets		
Cash and cash equivalents	802,679	933,205
Accounts receivable		
Customers, net of allowance;		
2024 - $121,040, 2023 - $144,789	936,044	935,592
Unbilled revenues	530,469	360,508
Other	289,273	968,780
Advances, affiliates	99,680	100,317
Inventories		
Natural gas	722,281	1,470,838
Materials and supplies	244,244	247,032
Prepaid taxes, net	315,247	150,651
Prepaid expenses and other	143,613	121,986
Total Current Assets	4,083,530	5,288,909
Total Assets	$ 32,135,068	$ 31,347,476

See Notes to Financial Statements

	2024	2023
LIABILITIES AND STOCKHOLDER'S EQUTIY		
Stockholder's Equity		
Common stock, no par or stated value, 1,000 shares authorized, issued and outstanding	$ 3,000,000	$ 3,000,000
Paid-in capital	94,885	94,885
Retained earnings	13,388,090	12,560,514
Total Stockholder's Equity	16,482,975	15,655,399
Long-Term Debt	5,736,464	4,833,386
Finance Lease Liabilities	101,926	63,708
Current Liabilities		
Line of credit	2,650,000	2,150,000
Current maturities of long-term debt	596,923	770,686
Current maturities of finance lease liabilities	40,425	41,073
Accounts payable	597,486	319,793
Due for purchased gas	495,267	952,840
Accrued expenses	326,713	502,350
Customer deposits	543,376	564,111
Over collected gas costs	676,841	1,335,592
Total Current Liabilities	5,927,031	6,636,445
Deferred Charges and Other Liabilities		
Deferred income taxes	2,694,069	2,964,000
Accrued postretirement cost	816,705	787,623
Regulatory liability	375,898	406,915
	3,886,672	4,158,538
Total Liabilities and Stockholder's Equity	$ 32,135,068	$ 31,347,476

Valley Energy, Inc.
Statements of Income
Years Ended December 31, 2024 and 2023

	2024	2023
Operating Revenues	$ 12,080,198	$ 12,476,673
Operating Expenses		
Gas	3,814,843	4,654,484
Distribution expenses		
Operation	1,933,271	1,679,763
Maintenance	611,071	566,764
Customer accounts	802,221	887,329
General and administrative	1,363,272	1,325,601
Depreciation	1,788,143	1,669,785
Taxes, other than income	194,168	147,810
	10,506,989	10,931,536
Operating Income Before Interest and Other Expenses	1,573,209	1,545,137
Other Income (Expenses)		
Interest expense	(428,818)	(642,291)
Other income	62,917	76,447
Other expense	(19,063)	(1,954)
	(384,964)	(567,798)
Income Before Income Taxes	1,188,245	977,339
Provision for Income Taxes	276,668	124,598
Net Income	$ 911,577	$ 852,741

Valley Energy, Inc.
Statements of Stockholder's Equity
Years Ended December 31, 2024 and 2023

	Common Stock	Paid-in Capital	Retained Earnings	Total
January 1, 2023	$ 3,000,000	$ 94,885	$ 11,811,937	$ 14,906,822
Dividends	-	-	(104,164)	(104,164)
Net income	-	-	852,741	852,741
December 31, 2023	$ 3,000,000	$ 94,885	$ 12,560,514	$ 15,655,399
Dividends	-	-	(84,001)	(84,001)
Net income	-	-	911,577	911,577
December 31, 2024	$ 3,000,000	$ 94,885	$ 13,388,090	$ 16,482,975

Valley Energy, Inc.
Statements of Cash Flows
Years Ended December 31, 2024 and 2023

	2024	2023
Operating Activities		
Net income	$ 911,577	$ 852,741
Items not requiring (providing) cash		
Depreciation and amortization	1,855,838	1,750,963
Deferred income taxes	(269,931)	(443,200)
Provision for credit losses on accounts receivable	(23,749)	(12,787)
Changes in		
Accounts receivable	532,843	(177,789)
Inventories	751,345	1,087,175
Prepaid expenses and other	(21,627)	(3,875)
Prepaid taxes, net	(164,596)	(95,381)
Regulatory assets/liabilities	(31,017)	(161,920)
Over/under recovered gas costs	(658,751)	2,936,320
Accounts payable and accrued expenses	74,195	191,060
Due for purchased gas	(457,573)	18,617
Customer deposits	(20,735)	120,125
Advances to affiliates	637	81
Accrued postretirement costs	56,943	114,070
Net Cash Provided by Operating Activities	2,535,399	6,176,200
Investing Activities		
Additions to utility plant, net	(3,751,019)	(1,975,933)
Net Cash Used in Investing Activities	(3,751,019)	(1,975,933)
Financing Activities		
Principal payments on finance lease liabilities	(60,220)	(63,367)
Borrowings under line of credit agreement	1,500,000	-
Repayments under line of credit agreement	(1,000,000)	(3,100,000)
Proceeds from issuance of long-term debt	1,500,000	-
Principal payments on long-term debt	(770,685)	(774,164)
Dividends paid	(84,001)	(104,164)
Net Cash Provided by (Used in) Financing Activities	1,085,094	(4,041,695)
Increase (Decrease) in Cash and Cash Equivalents	(130,526)	158,572
Cash and Cash Equivalents, Beginning of Year	933,205	774,633
Cash and Cash Equivalents, End of Year	$ 802,679	$ 933,205
Supplemental Cash Flows Information		
Interest paid	$ 428,818	$ 502,152
Income taxes paid	$ 702,607	$ 112,560
Right-of-use assets obtained in exchange for new finance lease liabilities	$ 97,790	$ 69,021

Valley Energy, Inc.
Notes to Financial Statements
December 31, 2024 and 2023

Note 1. Nature of Operations and Summary of Significant Accounting Policies

Nature of Operations

Valley Energy, Inc. ("Company"), a wholly-owned subsidiary of C & T Enterprises, Inc. ("C&T"), is a regulated public utility distributing natural gas to customers in the Sayre, Pennsylvania area, including Athens, Towanda, Wysox, and Waverly, New York. The Company's operations in Pennsylvania are regulated by the Pennsylvania Public Utility Commission ("PUC") and its operations in New York are regulated by the State of New York Public Service Commission ("NYPSC"). The Company extends unsecured credit to its customers.

Basis of Accounting

The Company maintains its accounting records in accordance with the Federal Energy Regulatory Commission's ("FERC") uniform system of accounts for public utilities as modified and adopted by the PUC and NYPSC. The accompanying financial statements and the related notes have been prepared on the basis of U.S. generally accepted accounting principles ("GAAP").

In accordance with FERC guidelines, the Company also maintains its accounts in accordance with Codification Topic 980, *Regulated Operations.* On a regular basis, the Company reevaluates its application of accounting for regulated operations. The Company has determined that regulatory assets and liabilities should continue to be accounted for under provisions of Codification Topic 980 because it is reasonable to assume that the Company will continue to be able to charge and collect its cost of service-based rates.

Purchased Gas

The Company obtains all of its natural gas from an agreement with an energy broker that expires in March 2027. Gas costs can be different than what is recovered in base charges, resulting in over or under collected gas costs.

Use of Estimates

The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates. Significant estimates include unbilled revenues, depreciation and postretirement benefits.

Cash and Cash Equivalents

The Company considers all liquid investments with original maturities of three months or less to be cash equivalents. At December 31, 2024 and 2023, cash equivalents consisted of a daily investment fund account.

At December 31, 2024, the Company's cash accounts exceeded federally insured limits by approximately $250,000.

Accounts Receivable

Accounts receivable include billed and unbilled amounts for services provided to customers for which the Company has an unconditional right to payment. The Company provides an allowance for credit losses, which is based upon a review of outstanding receivables, historical collection information and existing economic conditions adjusted for current conditions and reasonable and supportable factors.

Accounts receivable are ordinarily due 21 days after the issuance of the invoice. Accounts that are unpaid after the due date bear interest at 1.25% per month. Accounts past due more than 30 days are considered delinquent. Interest continues to accrue on delinquent accounts until the account is no longer classified as delinquent. Delinquent receivables are written off based on individual credit evaluation and specific circumstances of the customer.

During the years ended December 31, 2024 and 2023, credit loss expense (recoveries) related to doubtful accounts receivable, where collectability is not reasonably assured, was approximately $(12,000) and $66,000, respectively.

Inventories

Inventories consist of natural gas and materials and supplies and are stated at the lower of cost or net realizable value. Cost is determined based on average cost.

Utility Plant

Utility plant is carried at cost. Additions to utility plant and replacements of property are capitalized at cost. Retirements of utility plant or replacements are removed from utility plant accounts at cost and these costs plus cost of removal less salvage are charged to accumulated depreciation. Assets under finance lease obligations are amortized over the shorter of the lease term or respective estimated useful lives. Depreciation of utility plant is provided over the estimated useful life of the respective assets on a straight line basis, as follows:

Utility Plant	Years
Gas plant acquisition	8 - 41
Transmission plant	25 - 50
Distribution plant	33 - 50
General plant	10 - 15
Vehicles	5

Maintenance and repairs of property and replacements are charged to expense.

Impairment of Long-Lived Assets

The Company reviews the carrying amount of an asset for possible impairment whenever events or changes in circumstances indicate that such amounts may not be recoverable. If a long-lived asset is tested for recoverability and the undiscounted estimated future cash flows expected to result from the use and eventual disposition of the asset is less than the carrying amount of the asset, the asset cost is adjusted to fair value and an impairment loss is recognized as the amount by which the carrying amount of a long-lived asset exceeds its fair value. No asset impairment was recognized during the years ended December 31, 2024 and 2023.

Income Taxes

The Company is included in the consolidated federal and State of New York income tax returns filed by C&T. The Company files its own tax return in Pennsylvania. The Company's federal income tax expense is computed using the separate return method for intercorporate tax allocation.

The Company accounts for income taxes in accordance with income tax accounting guidance (Financial Accounting Standards Board ("FASB") Accounting Standards Codification ("ASC") 740, *Income Taxes*). The income tax accounting guidance results in two components of income tax expense: current and deferred. Current income tax expense reflects taxes to be paid or refunded for the current period by applying the provisions of the enacted tax law to the taxable income or excess of deductions over revenues. The Company determines deferred income taxes using the liability (or balance sheet) method. Under this method, the net deferred tax asset or liability is based on the tax effects of the differences between the book and tax bases of assets and liabilities, and enacted changes in tax rates and laws are recognized in the period in which they occur. Deferred income tax expense results from changes in deferred tax assets and liabilities between periods. Deferred tax assets are reduced by a valuation allowance if, based on the weight of evidence available, it is more likely than not that some portion or all of a deferred tax asset will not be realized.

Tax positions are recognized if it is more likely than not, based on the technical merits, that the tax position will be realized or sustained upon examination. The term more likely than not means a likelihood of more than 50%; the terms examined and upon examination also include resolution of the related appeals or litigation processes, if any. A tax position that meets the more likely than not recognition threshold is initially and subsequently measured as the largest amount of tax benefit that has a greater than 50% likelihood of being realized upon settlement with a taxing authority that has full knowledge of all relevant information. The determination of whether or not a tax position has met the more likely than not recognition threshold considers the facts, circumstances and information available at the reporting date and is subject to the management's judgment.

The Company recognizes interest and penalties on income taxes as a component of income tax expense.

Regulatory Matters

The Company is subject to the authoritative accounting guidance applicable to rate-regulated organizations. The Pennsylvania PUC and NYPSC approve natural gas rates for each state respectively. Certain items collected in rates have been recorded as regulatory liabilities. These amounts will be recognized as revenue in future periods as costs for which the amounts have been collected are incurred, or when authorized by the Pennsylvania PUC and NYPSC. Certain expenses have been recorded as regulatory assets, and management believes these amounts are probable of future rate recovery.

Revenue Recognition

Revenue from the sale of natural gas is recognized as gas is delivered to customers. Revenues also include amounts receivable from or payable to customers through gas recovery clauses, which are adjusted annually.

Costs that are recoverable or refundable in future periods through the gas recovery clauses are deferred. Costs that are refundable or recoverable in future periods through gas cost recovery rates are subject to audit and approval by the appropriate regulatory body. Changes to the related asset or liability amounts that result from these audits are recorded as a charge to current operations.

The amount and timing of revenue recognition varies based on the nature of the goods or services provided and the terms and conditions of the customer contract. Unbilled revenues of $530,469 and $360,508 at December 31, 2024 and 2023, respectively, represent amounts delivered through December 31 and not billed to the customers until the following month. Customer deposits of $543,379 and $564,111 at December 31, 2024 and 2023, respectively, represent amounts received in advance of services provided. See Note 12 for additional information about the Company's revenue.

For significant financing components, the Company elected a practical expedient, which allows an entity to recognize the promised amount of consideration without adjusting for the time value of money if the contract has a duration of one year or less, or if the reason the contract extended beyond one year is because the timing of delivery of the product is at the customer's discretion. As the Company's contracts are typically less than one year in length and do not have significant financing components, the Company does not present revenue on a present value basis.

Leases

The Company determines if an arrangement is a lease or contains a lease at inception. Leases result in the recognition of right-of-use (ROU) assets and lease liabilities on the balance sheets. ROU assets represent the right to use an underlying asset for the lease term, and lease liabilities represent the obligation to make lease payments arising from the lease, measured on a discounted basis. The Company determines lease classification as operating or finance at the lease commencement date. The ROU asset for finance leases are included in utility plant in our balance sheets.

At lease commencement, the lease liability is measured at the present value of the lease payments over the lease term. The ROU asset equals the lease liability adjusted for any initial direct costs, prepaid or deferred rent, and lease incentives. The Company has made a policy election to use a risk-free rate (the rate of a zero-coupon U.S. Treasury instrument) for the initial and subsequent measurement of all lease liabilities. The risk-free rate is determined using a period comparable with the lease term.

The lease term may include options to extend or to terminate the lease that the Company is reasonably certain to exercise. Lease expense is generally recognized on a straight-line basis over the lease term.

The Company has elected not to record leases with an initial term of 12 months or less on the balance sheets. Lease expense on such leases is recognized on a straight-line basis over the lease term.

Taxes Collected from Customers and Remitted to Governmental Authorities

Sales and gross receipts taxes collected from customers and remitted to governmental authorities are presented in the accompanying statements of income on a net basis.

Note 2. Leases

Nature of Leases

The Company has the following lease arrangements:

Finance Leases

These leases mainly consist of vehicles for the use of the Company. Termination of the leases generally are prohibited unless there is a violation under the lease agreement.

All Leases

The Company has no material related party leases. The Company's lease agreements do not contain any material residual value guarantees or material restrictive covenants.

Quantitative Disclosures

The lease cost and other required information for the years ended December 31, 2024 and 2023 are:

	2024	2023
Lease cost		
Finance lease cost		
Amortization of right-of-use asset	$ 56,627	$ 65,227
Interest on lease liabilities	7,767	9,196
Total lease cost	$ 64,394	$ 74,423

	2024	2023
Other information		
Cash paid for amounts included in the measurement of lease liabilities		
Financing cash flows from finance leases	$ 60,220	$ 63,367
Weighted-average remaining lease term		
Finance leases	3.5 years	3.6 years
Weighted-average discount rate		
Finance leases	1.65%	1.65%

See Note 6 for future minimum lease payments and reconciliation to the balance sheet at December 31, 2024.

Note 3. Utility Plant

Utility plant consists of the following at December 31, 2024 and 2023:

	2024	2023
Gas plant in service		
Gas plant acquisition	$ 4,621,318	$ 4,621,318
Distribution plant	38,070,873	36,457,686
General plant	8,758,243	7,137,584
Transmission plant	5,245,359	5,173,911
	56,695,793	53,390,499
Construction work-in-progress	277,959	101,383
	56,973,752	53,491,882
Accumulated depreciation	(29,002,827)	(27,581,623)
	$ 27,970,925	$ 25,910,259

Note 4. Regulatory Assets and Liability

Regulatory assets consist of the following at December 31, 2024 and 2023:

	2024	2023	Amortization Period
Rate case - 2022	$ 52,196	$ 104,391	3 years
Rate case - 2023	28,417	43,917	3 years
	$ 80,613	$ 148,308	

Regulatory liability of $375,898 and $406,915 at December 31, 2024 and 2023, respectively, consists of other postretirement benefits that resulted from unrecognized gains. The Company expects to recover the deferred other postretirement benefits consistent with the anticipated income recognition of other postretirement income.

Amortization expense was $67,695 and $81,178 for the years ended December 31, 2024 and 2023, respectively.

Note 5. Line of Credit

The Company has a $7,000,000 revolving line of credit with C&T payable on demand. At December 31, 2024 and 2023, there was $2,650,000 and $2,150,000 borrowed against this line, respectively. Interest varies based on the CoBank quoted variable rate. The rate was 6.39% and 7.41% on December 31, 2024 and 2023, respectively, and is payable monthly.

While the line of credit above is due on demand, the Company utilizes the financing for long-term operating purposes and does not have liquid funds available to repay the balance. The borrowings are available as a result of a line of credit agreement that C&T has with a third party, which is due in July 2026. C&T has no intentions of calling the debt before July 2026.

Note 6. Long-Term Debt and Finance Lease Liabilities

	2024	2023
Notes payable, C&T, quarterly principal and interest payments ranging from $12,530 to $50,284, interest ranging from 2.635% to 4.800%; collateralized by substantially all Company assets; due March 2032	$ 4,833,387	$ 5,387,593
Note payable, C&T, quarterly principal and interest payments ranging from $5,697 to $29,326, interest ranging from 2.41% to 3.22%; collateralized by substantially all Company assets; paid in full December 2024; available borrowings up to $1,125,000	-	216,479
Note payable, C&T, quarterly principal and interest payments of approximately $27,895, interest at 6.27%; collateralized by substantially all Company assets; due December 2054	1,500,000	-
Finance lease liability for transportation equipment, requiring monthly principal and interest payments ranging from $335 to $1,190; collateralized by leased equipment; payments due in varying amounts through October 2029	142,351	104,781
	6,475,738	5,708,853
Less current maturities	637,348	811,759
	$ 5,838,390	$ 4,897,094

Aggregate annual maturities of long-term debt and payments on finance lease liabilities at December 31, 2024, are:

	Long-Term Debt	Finance Lease Liabilities
2025	$ 596,923	$ 50,096
2026	641,918	44,723
2027	689,318	36,699
2028	739,255	21,725
2029	791,870	15,439
Thereafter	2,874,103	-
	$ 6,333,387	168,682
Less amount representing interest		26,331
Present value of future minimum lease payments		$ 142,351

Transportation equipment under finance lease liabilities is as follows:

	2024	2023
Transportation equipment	$ 376,912	$ 279,122
Accumulated depreciation	(282,668)	(180,464)
	$ 94,244	$ 98,658

C&T has a Master Letter of Credit agreement with National Cooperative Services Corporation. This Letter of Credit is for $7,000,000 and expires October 2029. The Company has the ability to post letters of credit with wholesale gas suppliers under the terms of this agreement. As of December 31, 2024 and 2023, the Company had $500,000 in outstanding letters of credit.

C&T holds a first lien secured interest in the assets of the Company that are located in Pennsylvania. C&T has pledged substantially all of the Company's assets as collateral for its borrowing arrangements.

Note 7. Income Taxes

The provision for income taxes includes these components:

	2024	2023
Taxes currently payable	$ 546,599	$ 567,798
Deferred income taxes	(269,931)	(443,200)
Income tax expense	$ 276,668	$ 124,598

A reconciliation of income tax expense at the statutory rate to the Company's actual income tax expense is shown below:

	2024	2023
Computed at the statutory rate (21%)	$ 249,500	$ 205,200
Increase (decrease) resulting from		
State income taxes	58,058	20,510
Other	(30,890)	(101,112)
Actual tax expense	$ 276,668	$ 124,598

The tax effects of temporary differences related to deferred taxes shown on the balance sheets were:

	2024	2023
Deferred tax assets		
Allowance for credit losses	$ 32,900	$ 39,900
Postretirement benefits	349,000	346,800
Other	204,700	47,400
	586,600	434,100
Deferred tax liabilities		
Depreciation	(3,236,500)	(3,340,200)
Other	(44,169)	(57,900)
	(3,280,669)	(3,398,100)
Net deferred tax liability	$ (2,694,069)	$ (2,964,000)

At December 31, 2024 and 2023, the Company had no allocation of C&T consolidated unused federal operating loss carryforwards.

Note 8. Pension and Postretirement Plans

Multiemployer Pension Plans

C&T is a member of the National Rural Electric Cooperative Association ("NRECA") Retirement Security Plan ("RS Plan"), a defined benefit pension plan qualified under Section 401 and tax-exempt under Section 501(a) of the Internal Revenue Code. It is a multiemployer plan under the accounting standards. The plan sponsor's Employer Identification Number is 53-0116145 and the Plan Number is 333.

A unique characteristic of a multiemployer plan compared to a single employer plan is that all plan assets are available to pay benefits of any plan participant. Separate asset accounts are not maintained for participating employers. This means that assets contributed by one employer may be used to provide benefits to employees of other participating employers.

C&T contributions to the RS Plan in 2024 and 2023 represented less than 5% of the total contributions made to the plan by all participating employers. C&T made contributions to the plan of $3,497,266 and $3,441,415 for the years ended December 31, 2024 and 2023, respectively. The Company reimbursed C&T $613,429 and $610,861 for its share of the contributions for the years ended December 31, 2024 and 2023, respectively. There have been no significant changes affecting the comparability of the 2024 and 2023 contributions.

In the RS Plan, a "zone status" determination is not required, and therefore not determined, under the *Pension Protection Act* ("PPA") of 2006. In addition, the accumulated benefit obligations and plan assets are not determined or allocated separately by individual employer. In total, the RS Plan was over 80% funded on January 1, 2024 and 2023, based on the PPA funding target and PPA actuarial value of assets on those dates.

Because the provisions of the PPA do not apply to the RS Plan, funding improvement plans and surcharges are not applicable. Future contribution requirements are determined each year as a part of the actuarial valuation of the plan and may change as a result of plan experience.

C&T is also a member of the NRECA SelectRE Pension Plan. C&T makes a matching contribution of 200% of the employees' contributions up to 2.5% of compensation. The Company reimbursed C&T $113,043 and $101,551 for its share of contributions for the years ended December 31, 2024 and 2023, respectively.

Other Postretirement Benefit Plan

C&T has a postretirement health care plan covering substantially all employees. The plan is unfunded. The estimated costs that will be paid after retirement are generally being accrued over the employees' active service periods to the dates they are fully eligible for benefits. The Company expects to contribute $82,000 to the plan in 2025. The following table sets forth the plan's funded status and the amounts of accrued benefit cost of the C&T plan and the Company's allocation based on an actuarial valuation as of December 31, 2024 and 2023.

	2024	2023
C&T's benefit obligation	$ 5,587,931	$ 5,725,208
Company's allocation of benefit obligation	$ 901,940	$ 844,997
C&T's accrued benefit cost	$ 5,587,931	$ 5,725,208
Company's allocation of accrued benefit cost	$ 901,940	$ 844,997
Amounts recognized in the Company's balance sheets:		
Current liability, included in accrued expenses	$ 85,235	$ 57,374
Non-current liability	816,705	787,623
	$ 901,940	$ 844,997
C&T's benefit expense	$ 472,065	$ 480,148
Company's allocation of benefit expense	$ 83,317	$ 80,892

The Company uses a December 31 measurement date for the plans. For measurement purposes, a 6.5% annual rate of increase in the per capita cost of covered health care benefits was assumed in 2024. The rate was assumed to decrease gradually to 4.75% in 2030 and remain at that level thereafter.

The benefit obligation was calculated assuming a weighted average discount rate of 5.15% and 5.10% in 2024 and 2023, respectively.

The amount of net gain and net prior service cost expected to be recognized by the Company during 2025 is $24,559 and $26,257, respectively.

Benefits expected to be paid by the Company in each of the next five years and in the aggregate for the five years thereafter are as follows:

2025	$	85,235
2026	$	87,392
2027	$	97,256
2028	$	50,966
2029	$	44,230
2030-2033	$	472,561

Because the Company is subject to regulation in the states in which it operates, it is required to maintain its accounts in accordance with the regulatory authority's rules and regulations, which may differ from other authoritative accounting pronouncements. In those instances, the Company follows the guidance of accounting for regulated operations. Based on prior regulatory practice, and in accordance with the related guidance, the Company recorded an unfunded postretirement obligation, which otherwise would be recognized as other comprehensive income, as a regulatory asset, and expects to recover those costs in rates charged to customers.

Note 9. Related Party Transactions

The Company has a contract for service with C&T to purchase all employee services. The contract automatically renews annually unless terminated by either party.

In the ordinary course of business, the Company's activities involve significant transactions with C&T. The activity between the Company and C&T for the years ended December 31, 2024 and 2023 and the effected account balances at December 31, 2024 and 2023, are as follows:

	2024	2023
Allocation of overhead recorded as operating expense	$ 151,581	$ 462,600
Other costs included in accounts receivable - other	$ 287,548	$ 269,069
Payroll related costs included in accrued expenses	$ 276,700	$ 237,033
Accrued vacation liability included in accrued expenses	$ 203,127	$ 171,127
Payroll costs paid in advance and included in advances, affiliates	$ 100,398	$ 100,398
Interest expense	$ 421,052	$ 632,935

The Company paid C&T $2,690,807 and $2,506,461 for payroll and $1,222,197 and $1,150,104 for benefits in 2024 and 2023, respectively.

Note 10. Significant Concentration

Accounting principles generally accepted in the United States of America require disclosure of certain vulnerabilities due to certain concentrations.

Major Suppliers

The Company obtains all of its natural gas from an agreement with an energy broker that expires on March 31, 2027. The Company obtained approximately 95% and 94% of its natural gas and distribution from three suppliers during 2024 and 2023.

Note 11. Commitments and Contingencies

The Company has guaranteed payments on note payables that are the obligation of C&T. At December 31, 2024, the amounts outstanding on these obligations are $6,333,387, which is fully recorded by the Company, see Note 6. This obligation is being repaid in quarterly payments of principal and interest through 2054. The Company would be required to perform under this guarantee if C&T were to default under the note payable and the bank were to demand the Company's performance.

Note 12. Revenue from Contracts with Customers

Performance Obligations

The Company's revenues are derived primarily from the sale of natural gas to customers. Customers consist of commercial, industrial and residential accounts within dedicated territories in the Sayre, Pennsylvania and Waverly, New York areas.

Rates charged for natural gas sales to customers are established by the Pennsylvania PUC and NYPSC for each state, respectively. The Company provides gas to customers as one stand-ready performance obligation. Sale of natural gas is recognized by the Company upon transfer of control of promised services to customers in an amount that reflects the consideration expected to be received in exchange for those services.

The Company transfers control of the natural gas to customers at each customer's meter point and the customers simultaneously receive and consume the benefits of the natural gas provided. Natural gas provided to customers is accounted for as a series of performance obligations. Progress towards completion is measured using the output method [hundreds of cubic feet (CCF) received by the customer], meter readings are taken at the end of each month for billing purposes, the quantity of energy transferred is determined after the meter readings. Payments from customers are received in accordance with each member's contract, which is ordinarily 21 days from the invoice date.

Revenue associated with the natural gas performance obligation to customers are recorded as sales of natural gas and capacity to customers in our accompanying statements of income.

The Company has determined that the nature, amount, timing and uncertainty of revenue and cash flows are primarily affected by factors that impact demand.

Contract Balances

The following table provides information about the Company's accounts receivable and customer deposits from contracts with customers:

	2024	2023
Accounts receivable - customers, beginning of year	$ 935,592	$ 1,290,993
Accounts receivable - customers, end of year	$ 936,044	$ 935,592
Unbilled revenues, beginning of year	$ 360,508	$ 386,906
Unbilled revenues, end of year	$ 530,469	$ 360,508
Customer deposits, beginning of year	$ 564,111	$ 443,986
Customer deposits, end of year	$ 543,376	$ 564,111

Note 13. Subsequent Events

Subsequent events have been evaluated through March 12, 2025, which is the date the financial statements were available to be issued.

Supplementary Information

Valley Energy, Inc.
Prepaid Taxes, Net
December 31, 2024 and 2023

	2024	2023
State gross receipts tax	$ (47,166)	$ (34,928)
State sales tax	(24,982)	(24,586)
State capital tax	14,074	14,074
Federal income tax	220,236	62,799
State income tax	(3,923)	(2,494)
PUC assessment	31,545	21,251
Local and county taxes	19,090	8,760
PURTA	71,757	73,316
State assessment surcharges	30,993	30,993
State use tax	3,623	1,466
	$ 315,247	$ 150,651

Valley Energy, Inc.
Operating Revenues and Taxes, Other Than Income
Years Ended December 31, 2024 and 2023

	2024	2023
Operating Revenues		
Residential sales	$ 6,664,399	$ 7,766,968
Commercial and industrial sales	2,710,690	3,250,473
Interruptible sales	140,340	491,605
Customers' forfeited discounts	21,703	33,946
Transportation sales	2,967,349	2,926,393
Under collected gas costs	(429,917)	(1,997,390)
Miscellaneous	5,634	4,678
	$ 12,080,198	$ 12,476,673
Taxes, Other Than Income		
Local and county taxes	$ 164,814	$ 118,300
PURTA	28,876	28,876
State use tax	478	634
	$ 194,168	$ 147,810

Valley Energy, Inc.
Distribution, Operation; Distribution, Maintenance;
Customer Accounts and General and Administrative Expenses
Years Ended December 31, 2024 and 2023

	2024	2023
Distribution, Operation Expenses		
Mains and services	$ 617,994	$ 653,629
Measuring and regulating station - general	131,889	129,147
Measuring and regulating station - city gate	58,400	51,713
Industrial/commercial meters and regulators	120,832	111,698
Meters and house regulators	201,104	168,279
Customer installations	217,960	201,884
Distribution load dispatching	371,874	344,474
Other operating expense	213,218	18,939
	$ 1,933,271	$ 1,679,763
Distribution, Maintenance Expenses		
Structures and improvements	$ 46,983	$ 27,173
Mains	165,561	189,498
Measuring and regulating station - general	118,236	111,033
Measuring and regulating station - industrial	4,473	5,866
Measuring and regulating station - city gate	6,926	21,404
Services	62,285	49,055
Meters and house regulators	163,705	120,015
Supervision and engineering	42,902	42,720
	$ 611,071	$ 566,764
Customer Accounts Expenses		
Meter reading	$ 32,540	$ 32,722
Customer records and collections	758,359	759,567
Uncollectible accounts (recoveries), net	(12,127)	65,661
Miscellaneous customer	23,449	29,379
	$ 802,221	$ 887,329
General and Administrative Expenses		
Salaries and benefits	$ 778,139	$ 714,291
Pensions and benefits	7,934	12,117
Office supplies and expense	38,485	34,086
Outside services	100,986	97,936
Property insurance	28,235	24,598
Injuries and damage	114,441	100,186
General advertising	17,140	17,619
Miscellaneous general	22,865	11,573
Directors' committee	63,995	63,504
Travel and training	30,316	56,272
Regulatory commission, net	113,345	143,125
Maintenance, general plant	47,391	50,294
	$ 1,363,272	$ 1,325,601

Valley Energy, Inc.
Balance Sheet, by Division
December 31, 2024

	Valley Energy of PA	Valley Energy of NY	Eliminations	Total
Assets				
Utility Plant, at Cost				
Gas plant in service	$ 49,702,507	$ 6,993,286	$ -	$ 56,695,793
Accumulated depreciation	(24,783,592)	(4,219,235)	-	(29,002,827)
	24,918,915	2,774,051	-	27,692,966
Construction work in progress	174,722	103,237	-	277,959
Net utility plant	25,093,637	2,877,288	-	27,970,925
Regulatory Asset	52,196	28,417	-	80,613
Current Assets				
Cash and cash equivalents	802,679	-	-	802,679
Accounts receivable				
Customers, net	624,279	311,765	-	936,044
Unbilled revenues	478,620	51,849	-	530,469
Other	255,292	33,981	-	289,273
Advances, affiliates	1,340,221	-	(1,240,541)	99,680
Inventories				
Natural gas	722,281	-	-	722,281
Materials and supplies	244,244	-	-	244,244
Prepaid taxes, net	188,263	126,984	-	315,247
Prepaid expenses and other	143,094	519	-	143,613
Total current assets	4,798,973	525,098	(1,240,541)	4,083,530
Other Assets				
Total assets	$ 29,944,806	$ 3,430,803	$ (1,240,541)	$ 32,135,068

See Independent Auditor's Report

	Valley Energy of PA	Valley Energy of NY	Eliminations	Total
Liabilities and Stockholder's Equity				
Stockholder's Equity				
Common stock, no par or stated value, 1,000 shares authorized, issued and outstanding	$ 673,408	$ 2,326,592	$ -	$ 3,000,000
Paid-in capital	94,885	-	-	94,885
Retained earnings (deficit)	14,404,719	(1,016,629)	-	13,388,090
Total Stockholder's Equity	15,173,012	1,309,963	-	16,482,975
Long-Term Debt	5,736,464	-	-	5,736,464
Finance Lease Liabilities	101,926	-	-	101,926
Current Liabilities				
Line of credit	2,650,000	-	-	2,650,000
Current maturities of long-term debt	596,923	-	-	596,923
Current maturities of finance lease labilities	40,425	-	-	40,425
Advances, due to affiliates	-	1,240,541	(1,240,541)	-
Accounts payable	597,486	-	-	597,486
Due for purchased gas	495,267	-	-	495,267
Accrued expenses	326,713	-	-	326,713
Customer deposits	394,763	148,613	-	543,376
Over collected gas costs	287,624	389,217	-	676,841
Total Current Liabilities	5,389,201	1,778,371	(1,240,541)	5,927,031
Deferred Charges and Other Liabilities				
Deferred income taxes	2,351,600	342,469	-	2,694,069
Accrued postretirement cost	816,705	-	-	816,705
Regulatory liability	375,898	-	-	375,898
Total Deferred Charges and Other Liabilities	3,544,203	342,469	-	3,886,672
Total Liabilities and Stockholder's Equity	$ 29,944,806	$ 3,430,803	$ (1,240,541)	$ 32,135,068

Valley Energy, Inc.
Schedule of Income, by Division
Year Ended December 31, 2024

	Valley Energy of PA	Valley Energy of NY	Eliminations	Total
Operating Revenues	$ 10,004,736	$ 2,075,462	$ -	$ 12,080,198
Operating Expenses				
Gas	3,075,692	739,151	-	3,814,843
Distribution expenses:				
Operation	1,434,232	499,039	-	1,933,271
Maintenance	493,659	117,412	-	611,071
Customer accounts	635,024	167,197	-	802,221
General and administrative	1,133,461	229,811	-	1,363,272
Depreciation	1,515,965	272,178	-	1,788,143
Taxes, other than income	29,354	164,814	-	194,168
	8,317,387	2,189,602	-	10,506,989
Operating Income (Loss) Before Interest and Other Expenses	1,687,349	(114,140)	-	1,573,209
Other Income (Expenses)				
Interest expense	(360,147)	(68,671)	-	(428,818)
Other income	62,917	-	-	62,917
Other expense	-	(19,063)	-	(19,063)
	(297,230)	(87,734)	-	(384,964)
Income (Loss) Before Income Taxes	1,390,119	(201,874)	-	1,188,245
Provision for Income Taxes	273,731	2,937	-	276,668
Net Income (Loss)	$ 1,116,388	$ (204,811)	$ -	$ 911,577

Valley Energy, Inc.
Utility Plant and Accumulated Depreciation - Pennsylvania
Year Ended December 31, 2024

Acct. No.	Account	Utility Plant: Cost January 1, 2024	Additions	Retirements	Cost December 31, 2024	Accumulated Depreciation: Balance January 1, 2024	Retirements	Cost of Removals	Salvage Received	Depreciation Rate	Depreciation Amount	Balance December 31, 2024
114	Gas Plan Acquisition Account	$ 3,361,289	$ -	$ -	$ 3,361,289	$ 2,759,038	$ -	$ -	$ -	4.21 %	$ 88,183	$ 2,847,221
366	Structures & Improvements	135,700	-	-	135,700	7,203	-	-	-	0.62	842	8,045
367	Mains	1,941,132	-	1,773	1,939,359	1,196,980	1,773	1,118	-	1.79	34,707	1,228,796
369	Meas. & Reg. Station Equipment	3,054,913	73,221	-	3,128,134	1,337,638	-	-	-	4.4	137,763	1,475,401
375	Structures & Improvements	204,061	-	-	204,061	100,177	-	-	-	2.63	5,363	105,540
376	Mains	15,077,654	153,348	691	15,230,311	6,212,375	691	1,208	-	2.02-3.15	347,821	6,558,297
378	Meas. & Reg Station Equipment	1,547,651	42,913	-	1,590,564	1,121,443	-	-	-	6.72	100,343	1,221,786
380	Services	9,818,071	626,092	19,024	10,425,139	4,307,717	19,024	9,922	-	3.04 - 3.41	336,452	4,615,223
381	Meters & Meter Installations	3,271,291	28,020	-	3,299,311	1,367,257	-	-	-	2.74	90,417	1,457,674
383	House Reg & House Reg & Installations	335,586	-	-	335,586	250,073	-	-	-	3.22	10,792	260,865
385	Ind. Meas. & Reg. Station Equipment	979,986	296,261	15,711	1,260,536	832,198	15,711	-	-	4.11	40,510	856,997
387	Other Equipment	9,978	-	-	9,978	7,287	-	-	-	3.66	364	7,651
390	Structures & Improvements	2,775,536	1,279,506	-	4,055,042	796,519	-	-	-	2.43	74,191	870,710
391	Office Furniture & Equipment	1,625,299	104,680	352,572	1,377,407	1,200,653	352,572	-	-	8.00 - 20.00	277,111	1,125,192
392	Transportation Equipment	1,110,179	146,971	42,480	1,214,670	1,004,675	42,480	-	-	10.82 - 3.33	68,719	1,030,914
393	Stores Equipment	48,547	-	-	48,547	22,732	-	-	-	6.67	2,804	25,536
394	Tools, Shop & Garage Equipment	697,136	21,566	1,338	717,364	497,746	1,338	-	-	5.00	27,591	523,999
396	Power Operated Equipment	470,863	28,666	-	499,529	333,593	-	-	-	11.76	48,647	382,240
397	Communication Equipment	234,555	10,523	-	245,078	169,188	-	-	-	6.67	10,527	179,715
398	Miscellaneous Equipment	14,718	-	-	14,718	895	-	-	-	6.67	895	1,790
301	Organization	18,666	-	-	18,666	-	-	-	-	-	-	-
304	Land & Land Rights	3,442	-	-	3,442	-	-	-	-	-	-	-
365.2	Rights of Way	42,166	-	-	42,166	-	-	-	-	-	-	-
374	Land & Land Rights	15,652	-	-	15,652	-	-	-	-	-	-	-
389	Land & Land Rights	105,121	425,137	-	530,258	-	-	-	-	-	-	-
		46,899,192	3,236,904	433,589	49,702,507	$ 23,525,387	$ 433,589	$ 12,248	$ -		1,704,042	$ 24,783,592
										Less charged to clearing	(117,364)	
	Construction work-in-process	66,574	108,148 (N)	-	174,722					Less depreciation expense allocated to New York operations	(70,713)	
		$ 46,965,766	$ 3,345,052	$ 433,589	$ 49,877,229					Total Depreciation	$ 1,515,965	

(N) Net Increase

Valley Energy, Inc.
Utility Plant and Accumulated Depreciation – New York
Year Ended December 31, 2024

Acct. No.	Account	Utility Plant: Cost January 1, 2024	Additions	Retirements	Cost December 31, 2024	Accumulated Depreciation: Balance January 1, 2024	Retirements	Cost of Removals	Salvage Received	Depreciation Rate	Depreciation Amount	Balance December 31, 2024
114	Gas Plant Acquisition Account	$ 1,260,029	$ -	$ -	$ 1,260,029	$ 866,388	$ -	$ -	$ -	3.00 %	$ 32,885	$ 899,273
375	Structures & Improvements	1,774	-	-	1,774	1,629	-	-	-	3.00	53	1,682
376	Mains	1,963,609	145,127	7,803	2,100,933	1,726,944	7,803	4,826	-	3.00	53,693	1,768,008
378	Meas. & Reg Station Equipment	263,628	8,157	-	271,785	39,327		-	-	3.00	8,133	47,460
380	Services	1,748,118	319,874	15,664	2,052,328	858,889	15,664	10,173	-	3.00	55,245	888,297
381	Meters & Meter Installations	1,023,151	52,228	-	1,075,379	431,444	-	-	-	3.00	45,664	477,108
383	House Reg & House Reg & Installations	30,840	-	-	30,840	41,607	-	-	-	3.00	925	42,532
385	Ind. Meas. & Reg. Station Equipment	162,879	-	-	162,879	90,348	-	-	-	3.00	4,867	95,215
301	Organization	6,084	-	-	6,084	-	-	-	-	3.00	-	-
302	Franchises/Consents	30,842	-	-	30,842	-	-	-	-	3.00	-	-
374	Land & Land Rights	353	-	-	353	(340)	-	-	-	3.00	-	(340)
		6,491,307	525,386	23,467	6,993,226	$ 4,056,236	$ 23,467	$ 14,999	$ -		201,465	$ 4,219,235
	Construction work-in-process	34,809	68,488 (N)	-	103,297							
							Add depreciation expense allocated to New York operations				70,713	
		$ 6,526,116	$ 593,874	$ 23,467	$ 7,096,523				Total Depreciation		$ 272,178	

(N) Net Increase

Valley Energy, Inc.
Prepaid Taxes, Net, by Division
December 31, 2024

	Valley Energy of PA	Valley Energy of NY	Total
State gross receipts tax	$ -	$ (47,166)	$ (47,166)
State sales tax	(11,104)	(13,878)	(24,982)
State capital tax	14,074	-	14,074
Federal income tax	88,381	131,855	220,236
State income tax	(8,210)	4,287	(3,923)
PUC assessment	31,545	-	31,545
Local and county taxes	-	19,090	19,090
PURTA	71,757	-	71,757
State assessment surcharges	-	30,993	30,993
State use tax	1,820	1,803	3,623
	$ 188,263	$ 126,984	$ 315,247

Valley Energy, Inc.
Operating Revenues and Taxes, Other Than Income, by Division
Year Ended December 31, 2024

	Valley Energy of PA	Valley Energy of NY	Total
Operating Revenues			
Residential sales	$ 5,287,284	$ 1,377,115	$ 6,664,399
Commercial and industrial sales	1,995,152	715,538	2,710,690
Interruptible sales	140,340	-	140,340
Customers' forfeited discounts	15,894	5,809	21,703
Transportation sales	2,735,441	231,908	2,967,349
Under collected gas costs	(174,685)	(255,232)	(429,917)
Miscellaneous	5,310	324	5,634
	$ 10,004,736	$ 2,075,462	$ 12,080,198
Taxes, Other Than Income			
Local and county taxes	$ -	$ 164,814	$ 164,814
PURTA	28,876	-	28,876
State use tax	478	-	478
	$ 29,354	$ 164,814	$ 194,168

Valley Energy, Inc.
Distribution, Operation; Distribution, Maintenance; Customer Accounts and General and Administrative Expenses, by Division
Year Ended December 31, 2024

	Valley Energy of PA	Valley Energy of NY	Total
Distribution, Operation Expenses			
Mains and services	$ 476,317	$ 141,677	$ 617,994
Measuring and regulating station - general	102,219	29,670	131,889
Measuring and regulating station - city gate	50,406	7,994	58,400
Industrial/commercial meters and regulators	102,462	18,370	120,832
Meters and house regulators	165,845	35,259	201,104
Customer installations	197,342	20,618	217,960
Distribution load dispatching	219,133	152,741	371,874
Other operating expense	120,508	92,710	213,218
	$ 1,434,232	$ 499,039	$ 1,933,271
Distribution, Maintenance Expenses			
Structures and improvements	$ 38,924	$ 8,059	$ 46,983
Mains	133,778	31,783	165,561
Measuring and regulating station - general	96,052	22,184	118,236
Measuring and regulating station - industrial	3,907	566	4,473
Measuring and regulating station - city gate	6,926	-	6,926
Services	54,019	8,266	62,285
Meters and house regulators	125,046	38,659	163,705
Supervision and engineering	35,007	7,895	42,902
	$ 493,659	$ 117,412	$ 611,071
Customer Accounts Expenses			
Meter reading	$ 25,596	$ 6,944	$ 32,540
Customer records and collections	610,474	147,885	758,359
Uncollectible accounts (recoveries), net	(20,260)	8,133	(12,127)
Miscellaneous customer	19,214	4,235	23,449
	$ 635,024	$ 167,197	$ 802,221
General and Administrative Expenses			
Salaries and benefits	$ 653,723	$ 124,416	$ 778,139
Pensions and benefits	6,502	1,432	7,934
Office supplies and expense	31,320	7,165	38,485
Outside services	84,558	16,428	100,986
Property insurance	23,202	5,033	28,235
Injuries and damage	93,900	20,541	114,441
General advertising	14,400	2,740	17,140
Miscellaneous general	19,683	3,182	22,865
Directors' committee	52,543	11,452	63,995
Travel and training	25,156	5,160	30,316
Regulatory commission, net	89,218	24,127	113,345
Maintenance, general plant	39,256	8,135	47,391
	$ 1,133,461	$ 229,811	$ 1,363,272

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December 19, 2024

VIA ELECTRONIC FILING

Rosemary Chiavetta, Secretary
Pennsylvania Public Utility Commission
Commonwealth Keystone Building
400 North Street, 2nd Floor
Harrisburg, PA 17120

RE: Valley Energy, Inc., Supplement No. 68 to Tariff Gas – Pa. P.U.C. No. 2 (State Tax Adjustment Surcharge Recalculation); Docket No._____

Dear Secretary Chiavetta:

Attached for filing with the Commission is Valley Energy, Inc.'s ("Valley" or the "Company") Supplement No. 68 to Tariff Gas-Pa. P.U.C. No. 2 ("Supplement No. 68"). Supplement No. 68 reflects a recalculation of the State Tax Adjustment Surcharge ("STAS"). Supplement No. 68 contains an issued date of December 19, 2024, and an effective date of January 1, 2025. This complies with the ten (10) day notice period for STAS modifications specified on page 81 of Valley's tariff.

This filing adjusts Valley's STAS to collect a prior period undercollection and to reflect changes in the Company's Corporate Net Income Tax and Utility Realty Tax. The documents supporting the Company's recalculation are set forth in Tab A, Attachments A, B, C, D, E, and F (computation of STAS for period January 1, 2025, through December 31, 2025). For completeness, a copy of proposed Supplement No. 68 is attached at Tab B. The supporting documents at Tab A demonstrate that Valley's STAS rate will increase from a surcredit of -0.0128% to a surcharge of 0.0095%, effective January 1, 2025. See Tab A.

If you have any questions regarding the documents, please feel free to contact the undersigned. Thank you.

Very truly yours,

Adeolu A. Bakare
MCNEES WALLACE & NURICK LLC

Counsel to Valley Energy, Inc.

AAB/leh
Enclosures
c: Certificate of Service
Erin Laudenslager, Bureau of Technical Utility Services (via E-mail)
Lori Burger, Bureau of Audits (via E-mail)

CERTIFICATE OF SERVICE

I hereby certify that I am this day serving a true copy of the foregoing document upon the participants listed below in accordance with the requirements of Section 1.54 (relating to service by a participant).

VIA E-MAIL

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Commonwealth of Pennsylvania
Office of Small Business Advocate
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Adeolu A. Bakare

Counsel to Valley Energy, Inc.

Dated this 19th day of December, 2024, in Harrisburg, Pennsylvania.

Supplement No. 68 to
Gas–Pa. P.U.C. No. 2
Forty-Seventh Revised Title Page
Canceling Forty-Sixth Revised Title Page

VALLEY ENERGY, INC. -
PENNSYLVANIA DIVISION

Rates and Rules
Governing and Furnishing of
Gas Service
in the

Boroughs of Athens, Monroe, Sayre, South Waverly
and Towanda; and the Townships of Asylum, Athens,
Monroe, North Towanda, Towanda, Ulster and Wysox
all in the County of Bradford

**THIS TARIFF MAKES {{CHANGES}} TO EXISTING RATES,
RULES AND REGULATIONS**
See Page No. 2

Issued: December 19, 2024 Effective: January 1, 2025

By: Edward E. Rogers, President & Chief Executive Officer
523 S. Keystone Ave.
Sayre, PA 18840-0340
(570) 888-9664

Valley Energy, Inc. – Pennsylvania Division

Supplement No. 68 to
Gas–Pa. P.U.C. No. 2
Sixtieth Revised Page No. 2
Canceling Fifty-Ninth Revised Page No. 2

LIST OF CHANGES MADE BY THIS SUPPLEMENT

Page 81:

Supplement No. 68 sets the Company's State Tax Adjustment Surcharge ("STAS") to 0.0095% effective on January 1, 2025. This recalculation is necessary to collect a prior period undercollection and to reflect changes in the Company's Corporate Net Income Tax and Utility Realty Tax.

By: Edward E. Rogers, President & Chief Executive Officer
523 S. Keystone Ave.
Sayre, PA 18840-0340
(570) 888-9664

Valley Energy, Inc. – Pennsylvania Division

Supplement No. 68 to
Gas–Pa. P.U.C. No. 2
Sixtieth Revised Page No. 7
Canceling Fifty-Ninth Revised Page No. 7

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(C) Indicates Change

Issued: December 19, 2024

Effective: January 1, 2025

By: Edward E. Rogers, President & Chief Executive Officer
523 S. Keystone Ave.
Sayre, PA 18840-0340
(570) 888-9664

Valley Energy, Inc. – Pennsylvania Division

Supplement No. 68 to
Gas–Pa. P.U.C. No. 2
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(C) Indicates Change

Issued: December 19, 2024

Effective: January 1, 2025

By: Edward E. Rogers, President & Chief Executive Officer
523 S. Keystone Ave.
Sayre, PA 18840-0340
(570) 888-9664

Valley Energy, Inc. – Pennsylvania Division

Supplement No. 68 to
Gas–Pa. P.U.C. No. 2
Twenty-Ninth Revised Page No. 81
Canceling Twenty-Eighth Revised Page No. 81

RIDER "B" - STATE TAX SURCHARGE

In addition to the charges provided in this tariff, a surcharge of 0.0095% will apply to all bills for sales service rendered on or after January 1, 2025. (C) (I) (C)

The above surcharge will be recomputed, using the elements prescribed by the Commission:

1. Whenever any of the tax rates used in calculation of the surcharge are changed.

2. Whenever the utility makes effective increased or decreased rates.

3. And on March 31,1992, and each year thereafter.

The above recalculation will be submitted to the Commission within ten days after the occurrence of the event or date which occasions such recomputation. If the recomputed surcharge is less than the one in effect the utility will, and if the recomputed surcharge is more than the one then in effect the utility may submit with such recomputation a tariff or supplement to reflect.

(C) Indicates Change (I) Indicates Increase

Issued: December 19, 2024

Effective: January 1, 2025

By: Edward E. Rogers, President & Chief Executive Officer
523 S. Keystone Ave.
Sayre, PA 18840-0340
(570) 888-9664

VALLEY ENERGY, INC.

Computation of State Tax Adjustment Surcharge
for the Period January 1, 2025 through December 31, 2025

			Amount	Attachment Number
1	Capital Stock Tax	$	-	**A**
2	Corporate Net Income Tax	$	(4,661)	**F**
3	Utility Realty Tax	$	1,957	**B**
4	Gross Receipts Tax	$	-	
5	Total of Lines 1, 2, 3, and 4	$	(2,703)	
6	PURTA Surcharge Rate Adjustment	$	-	**C**
7	STAS reconciliation for period January 1, 2024 through December 31, 2024	$	3,059	**D**
8	Total of Lines 5, 6 and 7	$	356	
9	Gross Intrastate Operating Revenues derived from service under rates subject to the jurisdiction of the Pa. Public Utility Commission for the period January 1, 2023 through December 31, 2023 (Page 10)	$	3,741,828	**E**
10	Surcharge rate to be applied for the period January 1, 2025 through December 31, 2025 (Line 8 divided by Line 9)		0.0095%	

VALLEY ENERGY, INC.

ATTACHMENT A

Calculation of Surcharge Rate 1/1/23 - 12/31/23

Corporate Stock Tax Phased out 2016
Capital Stock Tax @ .00 mills effective 1/1/19

1	Tax Base -- year 2016 (see attached page 2 of 2016 PA Corporate Tax Report	$ -	
2	Jurisdictional Apportionment Proportion	0.000000	
3	Tax Base Valley Energy - PA (Line 1 X Line 2)		$ -
4	Tax Millage in basic rates (2011)	0.000000	
5	Tax Millage effective 1/1/18	0.000000	
6	Effective Rate Increase (Decrease) (Line 4 minus Line 5)		0.000000
7	Total Capital Stock/Franchise Tax Increase (Decrease) (Line 3 X Line 6)		$ -

VALLEY ENERGY, INC.

ATTACHMENT B

Public Utility Realty Tax Assessment (PURTA)

Calculation of Surcharge Rate 1/1/25 - 12/31/25

1	7/31/2024 Notice of Determination Adjustments: State Tax Property Value at December 31, 2023	$ 1,512,392	
2	Pa. Public Utility Realty Tax (Based on applied rate of 23.7970 mills x Line 1)		$ 35,990
3	8/1/2023 Notice of Determination Adjustments: State Tax Property Value at December 31, 2022	$ 1,370,012	
4	Pa. Public Utility Realty Tax (Based on applied rate of 24.8531 mills x Line 1)		$ 34,049
5	2025 PURTA Adjustment (Line 2 minus Line 4)		$ 1,941

continued on page 3A

VALLEY ENERGY, INC.

ATTACHMENT B

Public Utility Realty Tax Assessment (PURTA)

Calculation of Surcharge Rate 1/1/25 - 12/31/25

1	Continued from page 3 (Line 5)		$ 1,941
	7/31/2024 Notice of Determination Adjustments:		
2	2019 PURTA		
	Liability Adjustment	$ 2	$ 2
3	2020 PURTA		
	Liability Adjustment	$ 1	$ 1
4	2021 PURTA		
	Liability Adjustment	$ 2	$ 2
5	2022 PURTA		
	Liability Adjustment	$ 11	$ 11
7	Total 2025 PURTA Adjustment (Lines 1 through 19)		$ 1,957

VALLEY ENERGY, INC.

ATTACHMENT C

Calculation of Surcharge Rate 1/1/25 - 12/31/25

Public Utility Realty Tax Assessment Surcharge

Tax Year Ending 2025

Projected taxable revenues for Pa. gross receipts tax for period January 1, 2025 to December 31, 2025 (Page 11)	$	5,581,890
PURTA surcharge rate as established by the Department of Revenue and published in the Pennsylvania Bulletin on September 21, 2024		0.0000
2025 PURTA Surcharge	$	-

VALLEY ENERGY, INC.

ATTACHMENT D

Reconciliation of State Tax Adjustment Surcharge
for the Period ending December 31, 2024

			Amount	Schedule Number
1	Capital Stock Tax	$	-	**1**
2	Corporate Net Income Tax	$	-	
3	Utility Realty Tax	$	762	**2**
4	Gross Receipts Tax	$	-	
5	Total of Items 1, 2, 3, and 4	$	762	
6	PURTA Surcharge Rate Adjustment	$	-	**3**
7	Total of Lines 5 and 6	$	762	
8	STAS reconciliation for period Jan. 1, 2023 through December 31, 2023	$	1,129	
9	Total of Lines 7 and 8	$	1,891	
10	STAS Revenue Collections (Page 9)	$	(1,169)	**4**
11	Balance to be (refunded) / collected (Line 9 minus Line 10)	$	3,059	

VALLEY ENERGY, INC.

ATTACHMENT D

Schedule 1

Reconciliation of State Tax Adjustment Surcredit
for the Period ending December 31, 2017

Calculation of Surcharge Rate 1/1/23 - 12/31/23

Corporate Stock Tax Phased out 2016
Capital Stock Tax @ .00 mills effective 1/1/17

1	Tax Base -- year 2016 (see attached page 2 of 2015 PA Corporate Tax Report)	$ -	
2	Jurisdictional Apportionment Proportion	0.000000	
3	Tax Base Valley Energy - PA (Line 1 X Line 2)		$ -
4	Tax Millage in basic rates (2011)	0.002890	
5	Tax Millage effective 1/1/18	0.000000	
6	Effective Rate Increase (Decrease) (Line 4 minus Line 5)		(0.002890)
7	Total Capital Stock/Franchise Tax Increase (Decrease) (Line 3 X Line 6)		$ -

VALLEY ENERGY, INC.

ATTACHMENT D

Reconciliation of State Tax Adjustment Surcharge
for the Period ending December 31, 2024

Schedule 2

Public Utility Realty Tax Assessment (PURTA)

Calculation of Surcredit Rate 1/1/24 - 12/31/24

1	8/1/2023 Notice of Determination Adjustments: State Tax Property Value at December 31, 2022	$ 1,370,012	
2	Pa. Public Utility Realty Tax (Based on applied rate of 24.8531 mills x Line 1)		$ 34,049
3	8/01/2022 Notice of Determination Adjustments: State Tax Property Value at December 31, 2021	$ 1,202,320	
4	Pa. Public Utility Realty Tax (Based on applied rate of 27.1851 mills x Line 1)		$ 32,685
5	2024 PURTA Adjustment (Lines 2 minus Line 4)		$ 1,364

Public Utility Realty Tax Assessment (PURTA)

8/01/2023 Notice of Determination Adjustments:

19	2018 PURTA Liability Adjustment	$ (74)
20	2019 PURTA Liability Adjustment	$ (67)
21	2020 PURTA Liability Adjustment	$ (88)
22	2021 PURTA Liability Adjustment	$ (373)
24	Total 2025 PURTA Adjustment (Lines 5 through 22)	$ 762

VALLEY ENERGY, INC.

ATTACHMENT D

Schedule 3

Reconciliation of State Tax Adjustment Surcredit
for the Period ending December 31, 2023

Public Utility Realty Tax Assessment Surcharge

Tax Year Ending 2024

Projected taxable revenues for Pa. gross receipts tax for period January 1, 2024 to December 31, 2024 (Page 12)	$	4,862,876
PURTA surcharge rate as established by the Department of Revenue and published in the Pennsylvania Bulletin on September 30, 2023		0.0000
2024 PURTA Surcharge	$	-

VALLEY ENERGY, INC.

For the Period January 1, 2024 through December 31, 2024

ATTACHMENT D

Schedule 4

STAS Revenue Collected / (Refunded) for period January 1, 2024 through December 31, 2024

Month	Gas Revenue Billed	Amount Tax Surcharge
January	$ 590,726	$ (439)
February	$ 715,455	$ (96)
March	$ 634,421	$ (86)
April	$ 550,524	$ (74)
May	$ 374,029	$ (35)
June	$ 264,098	$ (17)
July	$ 238,530	$ (15)
August	$ 232,789	$ (15)
September	$ 234,560	$ (15)
October	$ 251,869	$ (16)
November (estimated)	$ 359,052	$ (157)
December (estimated)	$ 400,549	$ (204)
Total STAS (Refunded) / Collected	$ 4,846,602	$ (1,169)

VALLEY ENERGY, INC.

ATTACHMENT E

OPERATING REVENUES

Revenue billed for 12 month audited period ending December 31, 2023

Residential Sales	$ 2,781,751		
Commercial & Industrial Sales	$ 871,911		
Interrruptible Sales	$ 56,709		
Transportation Sales	$ 2,209,091		
Customer' Forfeited Discounts	$ 26,929		
Total Gross Gas Revenue including Tax Surcharge		$	5,946,391
Less: Tax Surcharge collected / (refunded)		$	(4,528)
Less: Transportation Sales		$	2,209,091
Total Gas Revenue projected for application period January 1, 2025 through December 31, 2025		$	3,741,828

VALLEY ENERGY, INC.

Projected Revenues from Service Under Rates
for the Application Period January 1, 2025 to December 31, 2025

Month	MCF's	Base Rate Revenue	Forfeited Discounts	Projected Revenues
January	238,849	$ 703,739	$ 1,774	$ 705,513
February	257,978	$ 780,836	$ 2,588	$ 783,424
March	236,195	$ 702,148	$ 2,411	$ 704,559
April	197,925	$ 580,204	$ 2,467	$ 582,671
May	153,265	$ 438,971	$ 1,638	$ 440,609
June	107,464	$ 279,243	$ 1,107	$ 280,350
July	94,468	$ 239,368	$ 635	$ 240,003
August	91,435	$ 230,793	$ 557	$ 231,350
September	91,118	$ 241,068	$ 1,102	$ 242,170
October	115,076	$ 295,904	$ 986	$ 296,890
November	148,663	$ 412,334	$ 1,009	$ 413,343
December	222,692	$ 659,312	$ 1,696	$ 661,008
Totals	1,955,128	$ 5,563,920	$ 17,970	$ 5,581,890

VALLEY ENERGY, INC.

Revenues from Service Under Rates
for the Application Period January 1, 2024 to December 31, 2024

Month	MCF's	Base Rate Revenue	Forfeited Discounts	Total Revenues
January	148,242	$ 590,726	$ 1,774	$ 592,500
February	238,796	$ 715,455	$ 2,588	$ 718,043
March	216,303	$ 634,421	$ 2,411	$ 636,832
April	189,125	$ 550,524	$ 2,467	$ 552,991
May	134,008	$ 374,029	$ 1,638	$ 375,667
June	103,011	$ 264,098	$ 1,107	$ 265,205
July	94,341	$ 238,530	$ 635	$ 239,165
August	92,283	$ 232,789	$ 557	$ 233,346
September	89,519	$ 234,560	$ 594	$ 235,154
October	96,435	$ 251,869	$ 484	$ 252,353
November (estimated)	111,399	$ 359,052	$ 951	$ 360,002
December (estimated)	118,692	$ 400,549	$ 1,070	$ 401,618
Totals	1,632,154	$ 4,846,602	$ 16,274	$ 4,862,876

ATTACHMENT F

VALLEY ENERGY, INC

Pursuant to the Pennsylvania Utility Commission's State Tax Adjustment Surcharge (STAS) Procedures.

			Distribution Only
1	Net Operating Income Excluding Income Taxes		$1,438,331
2			
3	Synchronized interest expense:		
4	Rate base		1,715,915
5	Less: CWIP		0
6	Rate base for interest compuation		17,159,915
7	Weighted Cost of debt		2.154%
8	Synchronized interest expense		369,664
9	Taxable income before depreciation tax adjustments		1,068,667
10			
11	Pennsylvania depreciation adjustment:		
12	Tax depreciation (using DDB method)		(1,573,006)
13	Book depreciation		970,394
14	Pennsylvania depreciation adjustment		(602,612)
15	Pennsylvania taxable income		466,055
16	Regulatory Pennsylvania income tax expense	8.99%	41,898
		7.99%	37,238
17	Regulatory Pennsylvania Income Tax Expense Credit		(4,661)
	Monthly CNIT Credit		(388)

FTY & FPTY Wage & Salary Increase Detail

Valley Energy, Inc.

	Actual 2024	Budgeted 2025*	Budgeted 2026*
Total Wages	$ 2,393,835	$ 2,411,348	$ 2,529,390
Total Wage Increase		$ 17,513	$ 118,042
Annual Base Comp Adj		$ 65,756	$ 70,715
Market		$ 95,337	$ 56,077
Merit		$ 6,284	$ 15,527

* Note: Two full time positions have been re-classified from full-time to seasonal (May 1 thru - September 30). Working January 1, 2025 to September 30, 2025 and continue going forward, working May 1, 2026 to September 30, 2026.

JB-4

Valley Energy Company (PA)
Rate Case with Fully Projected Future Test Year 2026

Line	Acct	Account Description	Historic Year Actual Ended 12/31/2024	Future Test Year Ended 12/31/2025	Actual Ended 3/31/2025	Fully Projected Future Test Year Ended 12/31/2026
1		Distribution Expenses				
2	842	Fuel	21,175	21,130	10,613	20,347
3	870	Labor Supv /Eng.	212,953	239,030	59,115	260,547
4	871	Distrib Load Disp	6,180	6,763	5,791	7,101
5	874	Mains & Services	454,825	450,488	143,435	580,482
6	875	Meas & Reg- Gen	102,219	98,288	14,123	106,720
7	876	Ind / Com Meters, Reg	102,463	82,517	28,844	94,402
8	877	Meas & Reg- City gate	34,460	30,247	3,839	32,129
9	878	Meters & House Reg	165,846	144,252	31,208	159,622
10	879	Cust installations	197,343	173,184	53,571	190,044
11	880	Other operating exp	114,706	54,435	27,680	70,684
12	881	Rents	5,803	6,222	684	6,669
13		*Total Operating Expense*	1,417,971	1,306,556	378,904	1,528,746
14						
15	885	Supv and eng	35,008	37,738	9,598	39,622
16	886	Structures & improve	38,923	26,465	6,906	20,218
17	887	Mains	107,656	117,909	18,427	133,465
18	889	Meas & Reg- Gen	76,337	65,654	15,977	52,603
19	890	Meas & Reg- Ind	23,623	23,563	13,113	26,289
20	891	Meas & Reg- City gate	6,926	7,889	1,157	12,791
21	892	Services	54,019	58,597	8,431	71,281
22	893	Meters & House Reg	125,026	80,876	28,005	54,372
23		*Total Maintenance Expense*	467,518	418,691	101,615	410,641
24		*Total Operating & Maintenance Exp.*	1,885,489	1,725,247	480,519	1,939,388
25						
26		Customer Accounting & Collection Expenses:				
27	902	Meter Reading Exp	25,595	28,106	6,381	16,988
28	903	Cust Rec & Coll Exp	610,473	627,975	157,645	661,603
29	904	Uncollect Acct (Dist)	(20,260)	50,495	21,961	54,348
30	905	Miscellaneous cust	19,214	21,492	3,240	21,492
31	909	Info & Inst Advert	12,402	12,774	1,833	13,157
32	913	Advertising	1,998	2,057	665	2,098
33		*Total Cust Acct & Coll Expense*	649,422	742,899	191,725	769,686
34						
35		Administrative & General Expenses:				
36	920	A&G Salaries	655,639	634,899	166,445	683,674
37	921	Office Supp & Exp	56,476	79,370	21,710	81,390
38	923	Outside Services	84,557	80,660	44,272	85,495
39	924	Property Insurance	23,202	36,257	6,012	41,699
40	925	Injuries and damage	93,900	108,657	19,627	124,881
41	926	Empl Pens & Bene	6,502	9,898	1,086	10,194
42	928	Reg Comm Exp	89,218	99,514	24,878	105,514
43	930	General advertising	72,246	103,980	28,050	106,618
44	602	COVID-related	0	0	0	0
45	932	Maint Gen plant	37,342	40,805	7,698	39,240
46		*Total A&G Expense*	1,119,082	1,194,040	319,779	1,278,704
47						
48		**Total Oper & Maint Expense**	**3,653,994**	**3,662,186**	**992,023**	**3,987,778**
49						

JB-5

Valley Energy Company (PA)
Rate Case with Fully Projected Future Test Year 2026
Original Cost of Utility Plant in Service

Line	Acct No.	Account Title	Historic Actual 12/31/2024 Balance	Future Test Year 12/31/2025 Forecast	Actual 3/31/2025	Fully Projected Future Test Year 12/31/2026 Forecast
1	*Distribution Plant.*					
2	114	Gas Plant Acquisition Adjustment	3,361,289	3,361,289	3,361,289	3,361,289
3	366	Trans. Structures and improvements	117,592	117,592	117,593	117,592
4	367	Trans. Mains	1,917,201	1,917,201	1,917,200	1,917,201
5	369	Trans. Meas / Reg Sta Equp	402,427	402,427	402,428	402,427
6	374	Land & Land Rights	15,652	15,652	15,652	15,652
7	375	Structures and improvements	204,060	1,422,938	204,060	1,880,875
8	376S	Mains- Steel	3,820,156	3,864,065	3,820,158	3,908,144
9	376P	Mains- Plastic	11,410,116	11,632,816	11,506,081	12,820,732
10	378	Meas / Reg Sta Equp	1,590,567	1,997,492	1,590,566	2,242,371
11	380S	Services- Steel	581,198	572,171	581,200	561,786
12	380P	Services- Plastic	9,843,941	10,610,526	9,908,846	11,651,547
13	381	Meters	1,945,136	1,992,978	1,948,565	2,054,284
14	381RC	Transponders- Old	1,010,228	1,010,228	1,010,228	1,010,228
16	381AMR	Meters-AMR	282,510	284,519	282,511	293,640
17		Meters-Protection	61,435	72,046	61,435	72,046
18	383	House regulators	335,586	340,086	335,585	344,586
19	385	Indu Meas / Reg Sta Equp	1,260,536	1,286,936	1,296,880	1,300,136
20	387	Other equipment	9,978	9,978	9,978	9,978
21	Total Distribution Plant		38,169,608	40,910,940	38,370,255	43,964,513
23	*General Plant*					
24	390	Structures & Improvements	4,055,042	4,055,042	4,068,773	4,055,042
26	391	Office Furniture & Equipment	1,230,002	1,236,202	1,249,297	1,236,202
27	391C	Computer equipment	147,442	294,884	140,679	420,634
28	392	Transportation Equipment	1,214,676	1,294,676	1,236,634	1,394,676
29	393	Stores Equipment	48,547	68,547	48,547	68,547
30	394	Tools, Shop & Garage Equipment	717,363	786,113	739,051	831,113
31	396	Power Operated / Communication	499,528	499,528	499,527	499,528
32	397	Communication Equipment	245,077	245,577	245,077	245,577
33	398	Miscellaneous Equipment	14,718	14,718	14,718	14,718
34	301	Intangible plant, organization	22,107	22,107	22,108	22,107
34	389	Land & Land Rights	572,424	572,424	572,424	572,424
36		Total General Plant	8,766,926	9,089,818	8,836,835	9,360,568
38		Less: Acquisition, CIAC	(3,361,289)	(3,361,289)	(3,361,289)	(3,361,289)
39		Total Plant in Service	$43,575,245	$46,639,469	$43,845,801	$49,963,792

Valley Energy, Inc.
Allocating Percentages
Based on 12 Months Ended
December 31, 2023

EFFECTIVE DATE - April 1, 2024

	PENNSYLVANIA UTILITY	NEW YORK UTILITY	TOTAL
Operating Expense Ratio			
Total Operating and Maintenance Expense	3,571,030	888,427	4,459,457
Minus: Allocations from C&T payroll charged to expense	294,281	61,963	356,244
Net O & M Expense	3,276,749	826,464	4,103,213
O&M Ratio	0.79858	0.20142	1.00000
Investment in Plant Ratio (12month average)			
Gross Plant	30,231,971	4,905,421	35,137,392
Less: Reserve for Depreciation	13,815,569	3,134,763	16,950,332
Net Plant	16,416,402	1,770,658	18,187,060
Net Plant Ratio	0.90264	0.09736	1.00000
Average Customer Ratio			
Customer (12 Month Average)	7384	2017	9,401
Customer Ratio	0.78543	0.21457	1.00000
Payroll Ratio			
Payroll Charged to Expense	1,025,293	278,082	1,303,376
Payroll Ratio	0.78664	0.21336	1.00000
AVERAGE FACTOR	**0.818325**	**0.181675**	**1.00000**

Prepared by: _____

Reviewed by: _____

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Valley Statement No. 5R

BEFORE
THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	**:**	
	:	
v.	**:**	**Docket No. R-2025-3054393**
	:	
Valley, Energy, Inc.	**:**	

REBUTTAL TESTIMONY

AND EXHIBITS

OF

JAMIE BEALE

ON BEHALF OF

VALLEY ENERGY, INC.

AUGUST 13, 2025

BEFORE
THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	**Docket No. R-2025-3054393**
	:	
Valley Energy, Inc.	:	

REBUTTAL TESTIMONY OF JAMIE BEALE
ON BEHALF OF VALLEY ENERGY, INC.

Q. Please state your name and business address.

A. My name is Jamie Beale, and my business address is 523 Keystone Avenue, Sayre, Pennsylvania.

Q. Are you the same Jamie Beale who previously submitted Direct Testimony in this proceeding on behalf of Valley Energy, Inc. ("Valley" or "Company")?

A. Yes. Terms defined in my direct testimony have the same meaning in this rebuttal testimony.

Q. What is the purpose of your testimony today?

A. The purpose of my testimony is to rebut the testimony of the following witnesses' direct testimony:

- OCA Witness Wise regarding her proposed implementation of formal policies and procedures surrounding security deposits and payment plan tracking.
- OCA Witness Meyer regarding purchased gas cost expenses and revenues, and his proposed adjustments to the Company's account 925 (Injuries and Damages).
- I&E Witness Wilson regarding her proposed adjustments to the Company's operations and maintenance expenses.

- I&E Witness Sakaya regarding his proposed reporting requirements on plant additions.

PROPOSED ADJUSTMENTS

Q. Ms. Beale, will you be the only respondent addressing adjustments to expenses and rate base proposed by the OCA and I&E Witnesses in this proceeding?

A. No. Mr. Gorman and Mr. Rogers will also address the proposed expense adjustments. To the extent I do not address a proposed adjustment in my testimony, such omission does not represent my acceptance of, or agreement with, the proposed adjustment.

INJURIES AND DAMAGES EXPENSE

Q. Did I&E Witness Wilson and OCA Witness Meyer propose adjustments to Valley's Injuries and Damages Expense (I&E Statement No. 1 at 26-28), (OCA Statement No. 1 at 7-12)?

A. Yes. Ms. Wilson proposes an adjustment of $15,935 to the Company's Fully Projected Future Test Year ("FPFTY") Injuries and Damages Expense based on the amount for the policy period ending May 1, 2026. Mr. Meyer proposed an adjustment of $30,981 to the Company's FPFTY Injuries and Damages Expense based on holding the account to the Historic Test Year ("HTY") 2024 level of exposure. Both witnesses object to Valley's 17% adjustment from the HTY to the FPFTY, which we calculated based on average yearly increases from 2021 to 2024.

Q. Did you find the adjustments to Valley's Injuries and Damages Expense proposed by I&E and OCA reasonable?

A. Yes, but for different reasons. As Mr. Rogers stated in his response to I&E-RE-13-D the Company has shopped around to reduce the overall insurance costs. As a result of those efforts, we were able to find comparable coverage at a lower premium. Based on this, the Company would be comfortable accepting the reduction proposed by Mr. Meyer.

Q. Do you have any comments in response to I&E's proposed adjustments to Employee Pension and Benefits?

A. Yes. I&E Witness Wilson proposes to disallow $10,194 of costs related to Employee Benefits and Pension (I&E Statement No. 1 at 18-19). The "Benefits and Pension" expenses at issue are employee recognition costs. I am informed by counsel that the Commission has a long history of supporting the inclusion of this type of expense in rates, because employee recognition events can incentivize an effective workforce. For example, the Commission allowed Citizens' employee recognition expenses in their 2019 base rate case.[1] At every Valley employee appreciation event, remarks are made by the Company's senior staff recognizing employee contributions to the Company as well as including safety and/or training messages. An important benefit of these minor costs is to improve morale, which reduces turnover and improves customer service. Accordingly, the Company should be permitted to recover expenses for employee recognition events.

[1] *Pa. PUC v. Citizens Electric Company of Lewisburg, PA,* Docket No. R-2019-3008212 (Order Entered April 29, 2020). See generally Employee Pension & Benefits (Account 926) at 73-75.

Q. Do you have any comments in response to I&E's proposed adjustments to Advertising Expenses?

A. Yes. I&E Witness Wilson proposes to disallow $2,098 of costs related to Advertising (I&E Statement No. 1 at 19-21). The advertisements convey safety and other information to the ratepayers, therefore, this is a proper expense.

Q. Do you have any comments in response to the proposed I&E adjustments to Dues/Memberships Expenses?

A. Yes. I&E Witness Wilson proposes to disallow $3,569 of costs related to Dues and Memberships (I&E Statement No. 1 at 21-23). The Company agrees that dues and subscriptions costs for fraternal, social clubs, and chamber of commerce organizations as well as lobbying expenses should not be included. This results in a reduction of $1,344, not $3,569. Attached as Exhibit__(JB-1R) is a segregation of the originally-claimed costs to support the revised level.

Q. Do you have any comments in response to I&E's proposed adjustments to Property Insurance Expenses?

A. Yes. I&E Witness Wilson proposes to disallow $5,843 of costs related to Property Insurance Expense (I&E Statement No. 1 at 24-25). As Mr. Rogers stated in his response to I&E-RE-12-D, the Company has shopped around to reduce the overall insurance costs ($41,699 included in filing, $38,819 are actual new rates). Based on this, the Company would be comfortable accepting a reduction of $2,880 ($41,699 minus $38,819) rather than the reduction of $5,843 suggested by Ms. Wilson.

OTHER TOPICS

Q. Do you have any comments in response to I&E's proposed reporting requirements on Plant Additions?

A. Yes. I&E Witness Sakaya proposes that the Company be required to provide I&E and the Office of Consumer Advocate with an update to Valley Exhibit HSG-1, Schedule C3 no later than April 1, 2026, under this docket number, which should include actual plant additions and retirements by month for the year ending December 31, 2025. An additional update should be required for actual plant additions and retirements by month through December 31, 2026, no later than April 1, 2027 (I&E Statement No. 3 at 6). The Company is willing to provide the requested updates.

Q. Do you have updates for expenses and plant additions through the 2nd Quarter 2025?

A. Yes. Attached as Exhibits__(JB-2R) and (JB-3R) are the actual experienced expenses and plant additions/retirements through the end of the 2nd Quarter.

Q. Did OCA Witness Wise propose any recommendations regarding security deposits?

A. Yes. OCA Witness Wise proposes that the Company be required to show in rebuttal that there are formal policies and procedures in place to support the practice of refunding a security deposit where it should not have been charged. She also recommended the Company should permit the customer to decide whether they want to receive the returned security deposit as a refund or credit to their utility account balance (OCA Statement No. 4 at 8-9).

Q. Do you have any comments in response to OCA's proposed recommendations regarding security deposits?

A. Yes. The Company feels that no formal policies and procedures are necessary. Our Customer Service Representatives ("CSR") are thoroughly trained, which is sufficient. With a small staff, we find that training and ongoing informal management of our CSR team are the best ways to create a customer-friendly environment.

Q. Please address the OCA request regarding security deposit returns.

A. We provide all customers who are receiving a security deposit refund the same treatment. The goal is to refund the customer as quickly and efficiently as possible. This is accomplished by crediting the deposit against any current charges. A customer that is leaving our service territory would get a refund of the security deposit. Providing an option would involve additional administrative tasks and would take more time to return the deposit because the Company would need to wait for a customer's decision before proceeding. Ultimately, as long as the customer intends to pay their current and future bills, the effect is the same.

Q. Did OCA Witness Wise propose any recommendations regarding payment plans?

A. Yes. OCA Witness Wise proposes that the Company establish metrics for measuring the success of payment plans and set documented plan policies, including how the Federal Poverty Income ("FPI") ranges are used, what verification is needed for low-income verification, and how payments and terms are calculated. (OCA Statement No. 4 at 9-11).

Q. Do you have any comments in response to OCA's proposed recommendations regarding payment plans?

A. Yes, the OCA's request for policies and metrics is not necessary. As previously mentioned, we have a small Customer Service Department team that handles payment arrangements. Customers with more significant arrearages or more complicated situations are addressed by the manager of the department or myself. Informal training and performance coaching are more effective than formal policies for our situation.

The OCA's request for Valley to evaluate the effectiveness of payment plans is inappropriate. The Company follows the PUC Chapter 14 guidelines, even though Chapter 14 is no longer in effect. Additional tracking and reporting are not necessary.

Our due diligence and financial management are about getting our customers to pay their overdue invoices. I review general billing and collection matters on a regular basis, including the status of payment arrangements. For customers that are unable to pay their invoices, the Company's Customer Service Department connects them with assistance options. Unfortunately, there are times when service must be terminated, but that is not due to a failure in Company procedures. It is also not necessarily the result of the customer having agreed to a payment arrangement that they cannot afford, which the OCA appears to assume is the cause of broken payment arrangements. We are very proud of how our Customer Service Department team tries to connect our customers to available resources in order to help keep their service active.

Q. Did the OCA have questions regarding Purchased Gas Expense?

A. Yes. OCA Witness Meyer requested clarification on the difference between the revenue and expense adjustments for Purchased Gas Expense removed from the HTY (OCA Statement No. 1 at 16).

Q. Do you have any comments in response to OCA's questions regarding Purchased Gas Expense?

A. Yes. First, I would note that the removal of the Purchased Gas Expenses and revenues for the HTY does not impact our revenue requirement calculation. Valley's rates are unbundled. The revenues and expenses are booked accurately, which is easier due to unbundled rates. We are subject to periodic audits by the Commission for our Gas Cost Rate ("GCR").

Purchased Gas Revenues and expenses can show a mismatch from year to year because of how the GCR is calculated and reconciled. We calculate the GCR once per year based on the projected costs and sales for the upcoming period. Those projections are subsequently reconciled against actual costs and revenues, which is reflected in the E-Factor for the next rate period. It can be positive or negative to account for the prior period over or under collection. Exhibit__(JB-4R) shows the E-Factor levels in effect during 2024 and the monthly impact. In this instance, it was a negative E-factor, which was refunding a prior period overcollection.

Q. Does this complete your Rebuttal Testimony?

A. Yes.

Valley Statement No. 5R

BEFORE

THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	**:**	
	:	
v.	**:**	**Docket No. R-2025-3054393**
	:	
Valley, Energy, Inc.	**:**	

EXHIBITS

OF

JAMIE BEALE

ON BEHALF OF

VALLEY ENERGY, INC.

AUGUST 13, 2025

EXHIBIT__(JB-1R)

Company	Originally Claimed FPFTY 2026	Reduction	Revised FPFTY 2026
American Gas Association	$ 7,534	$ 285	$ 7,249
Northeast Gas Association	$ 5,978	$ -	$ 5,978
Sayre Rotary Club	$ 608	$ 608	$ -
National Fire Protection Association	$ 205	$ -	$ 205
Central Bradford Chamber of Commerce	$ 384	$ 384	$ -
C&T - ForvisMazars - Hotline	$ 362	$ -	$ 362
Energy Association of Pennsylvania	$ 2,224	$ 67	$ 2,157
	$ 17,295	$ 1,344	$ 15,951

EXHIBIT__(JB-2R)

COMPARISON AS FILED TEST YEAR TO ACTUAL EXPENSES THROUGH 2ND Q

Line	Acct	Account Description	Historic Year Actual Ended 12/31/2024	Future Test Year Ended 12/31/2025	Actual Ended 3/31/2025	Actual Ended 6/30/2025	Fully Projected Future Test Year Ended 12/31/2026
1		Distribution Expenses					
2	842	Fuel	21,175	21,130	10,613	17,466	20,347
3	870	Labor Supv /Eng.	212,953	239,030	59,115	116,702	260,547
4	871	Distrib Load Disp	6,180	6,763	5,791	5,791	7,101
5	874	Mains & Services	454,825	450,488	143,435	291,277	580,482
6	875	Meas & Reg- Gen	102,219	98,288	14,123	46,979	106,720
7	876	Ind / Com Meters, Reg	102,463	82,517	28,844	49,147	94,402
8	877	Meas & Reg- City gate	34,460	30,247	3,839	9,322	32,129
9	878	Meters & House Reg	165,846	144,252	31,208	60,441	159,622
10	879	Cust installations	197,343	173,184	53,571	93,888	190,044
11	880	Other operating exp	114,706	54,435	27,680	48,852	70,684
12	881	Rents	5,803	6,222	684	4,956	6,669
13		*Total Operating Expense*	1,417,971	1,306,556	378,904	744,820	1,528,746
14							
15	885	Supv and eng	35,008	37,738	9,598	18,629	39,622
16	886	Structures & improve	38,923	26,465	6,906	11,143	20,218
17	887	Mains	107,656	117,909	18,427	29,030	133,465
18	889	Meas & Reg- Gen	76,337	65,654	15,977	34,673	52,603
19	890	Meas & Reg- Ind	23,623	23,563	13,113	15,603	26,289
20	891	Meas & Reg- City gate	6,926	7,889	1,157	1,877	12,791
21	892	Services	54,019	58,597	8,431	13,056	71,281
22	893	Meters & House Reg	125,026	80,876	28,005	53,855	54,372
23		*Total Maintenance Expense*	467,518	418,691	101,615	177,867	410,641
24		*Total Operating & Maintenance Exp.*	1,885,489	1,725,247	480,519	922,687	1,939,388
25							
26		Customer Accounting & Collection Expenses:					
27	902	Meter Reading Exp	25,595	28,106	6,381	11,571	16,988
28	903	Cust Rec & Coll Exp	610,473	627,975	157,645	319,619	661,603
29	904	Uncollect Acct (Dist)	(20,260)	50,495	21,961	32,551	54,348
30	905	Miscellaneous cust	19,214	21,492	3,240	6,862	21,492
31	909	Info & Inst Advert	12,402	12,774	1,833	5,463	13,157
32	913	Advertising	1,998	2,057	665	1,213	2,098
33		*Total Cust Acct & Coll Expense*	649,422	742,899	191,725	377,278	769,686
34							
35		Administrative & General Expenses:					
36	920	A&G Salaries	655,639	634,899	166,445	327,676	683,674
37	921	Office Supp & Exp	56,476	79,370	21,710	42,445	81,390
38	923	Outside Services	84,557	80,660	44,272	52,052	85,495
39	924	Property Insurance	23,202	36,257	6,012	15,155	41,699
40	925	Injuries and damage	93,900	108,657	19,627	37,645	124,881
41	926	Empl Pens & Bene	6,502	9,898	1,086	1,350	10,194
42	928	Reg Comm Exp	89,218	99,514	24,878	49,756	105,514
43	930	General advertising	72,246	103,980	28,050	58,746	106,618
44	602	COVID-related	0	0	0	0	0
45	932	Maint Gen plant	37,342	40,805	7,698	11,134	39,240
46		*Total A&G Expense*	1,119,082	1,194,040	319,779	595,960	1,278,704
47							
48		**Total Oper & Maint Expense**	**3,653,994**	**3,662,186**	**992,023**	**1,895,924**	**3,987,778**
49							

Rate Case with Fully Projected Future Test Year 2026
Original Cost of Utility Plant in Service

Line	Acct No.	Account Title	Historic Actual 12/31/2024 Balance	Future Test Year 12/31/2025 Forecast	Actual 3/31/2025	Actual 6/30/2025	Fully Projected Future Test Year 12/31/2026 Forecast
1	*Distribution Plant.*						
2	114	Gas Plant Acquisition Adjustment	3,361,289	3,361,289	3,361,289	3,361,289	3,361,289
3	366	Trans. Structures and improvements	117,592	117,592	117,593	117,593	117,592
4	367	Trans. Mains	1,917,201	1,917,201	1,917,200	1,917,200	1,917,201
5	369	Trans. Meas / Reg Sta Equp	402,427	402,427	402,428	402,428	402,427
6	374	Land & Land Rights	15,652	15,652	15,652	15,652	15,652
7	375	Structures and improvements	204,060	1,422,938	204,060	216,215	1,880,875
8	376S	Mains- Steel	3,820,156	3,864,065	3,820,158	3,820,158	3,908,144
9	376P	Mains- Plastic	11,410,116	11,632,816	11,506,081	11,570,992	12,820,732
10	378	Meas / Reg Sta Equp	1,590,567	1,997,492	1,590,566	1,590,566	2,242,371
11	380S	Services- Steel	581,198	572,171	581,200	580,464	561,786
12	380P	Services- Plastic	9,843,941	10,610,526	9,908,846	10,002,718	11,651,547
13	381	Meters	1,945,136	1,992,978	1,948,565	1,950,483	2,054,284
14	381RC	Transponders- Old	1,010,228	1,010,228	1,010,228	1,010,228	1,010,228
16	381AMR	Meters-AMR	282,510	284,519	282,511	282,511	293,640
17		Meters-Protection	61,435	72,046	61,435	61,435	72,046
18	383	House regulators	335,586	340,086	335,585	337,496	344,586
19	385	Indu Meas / Reg Sta Equp	1,260,536	1,286,936	1,296,880	1,299,100	1,300,136
20	387	Other equipment	9,978	9,978	9,978	9,978	9,978
21	Total Distribution Plant		38,169,608	40,910,940	38,370,255	38,546,506	43,964,513
22							
23	*General Plant*						
24	390	Structures & Improvements	4,055,042	4,055,042	4,068,773	4,172,826	4,055,042
26	391	Office Furniture & Equipment	1,230,002	1,236,202	1,249,297	1,287,507	1,236,202
27	391C	Computer equipment	147,442	294,884	140,679	140,679	420,634
28	392	Transportation Equipment	1,214,676	1,294,676	1,236,634	1,236,634	1,394,676
29	393	Stores Equipment	48,547	68,547	48,547	48,547	68,547
30	394	Tools, Shop & Garage Equipment	717,363	786,113	739,051	744,489	831,113
31	396	Power Operated / Communication	499,528	499,528	499,527	523,660	499,528
32	397	Communication Equipment	245,077	245,577	245,077	245,077	245,577
33	398	Miscellaneous Equipment	14,718	14,718	14,718	14,718	14,718
34	301	Intangible plant, organization	22,107	22,107	22,108	22,108	22,107
34	389	Land & Land Rights	572,424	572,424	572,424	572,424	572,424
36		Total General Plant	8,766,926	9,089,818	8,836,835	9,008,669	9,360,568
37							
38		Less: Acquisition, CIAC	(3,361,289)	(3,361,289)	(3,361,289)	(3,361,289)	(3,361,289)
39		Total Plant in Service	$43,575,245	$46,639,469	$43,845,801	$44,193,886	$49,963,792

E Factor Analysis for 2024 **EXHIBIT__(JB-4R)**

Volumes in CCFS

MONTH	RES GEN. VOLUMES	RES HEAT VOLUMES	COMM GEN VOLUMES	COMM HEAT VOLUMES	INDUSTRIAL VOLUMES	INDUSTRIAL CUSTOMERS	INTERRUPTIBLE VOLUMES	TOTAL VOLUMES
Jan-24	675	810,876	7,760	358,027	10,435	0	0	1,187,773
Feb-24	873	955,183	6,736	413,536	12,377	0	510	1,389,215
Mar-24	615	794,948	6,061	339,873	10,426	0	0	1,151,923
Apr-24	664	648,809	5,583	274,559	6,951	0	2,700	939,266
May-24	767	333,079	5,909	135,515	3,133	0	26,540	504,943
Jun-24	1,261	119,392	5,324	59,115	1,115	0	46,880	233,087
Jul-24	950	69,780	4,800	39,855	502	0	20,260	136,147
Aug-24	971	64,867	5,072	40,892	577	0	49,050	161,429
Sep-24	1,378	79,103	5,042	46,853	706	0	41,620	174,702
Oct-24	782	103,683	4,907	57,071	669	0	29,410	196,522
Nov-24	651	336,650	6,605	135,710	3,182	0	21,160	503,958
Dec-24	882	693,560	6,005	288,099	7,618	0	13,430	1,009,594
TOTAL	**10,469**	**5,009,930**	**69,804**	**2,189,105**	**57,691**	**0**	**251,560**	**7,588,559**

E Factor rate November 1, 2023 - October 31, 2024 (per ccf) -0.11825

E Factor rate November 1, 2024 - October 31, 2025 (per ccf) -0.06628

MONTH	RES GEN. E FACTOR	RES HEAT E FACTOR	COMM GEN E FACTOR	COMM HEAT E FACTOR	INDUSTRIAL E FACTOR	INDUSTRIAL E FACTOR	INTERRUPTIBLE E FACTOR	TOTAL E FACTOR
Jan-24	$ (79.82)	$ (95,886.09)	$ (917.62)	$ (42,336.69)	$ (1,233.94)	$ -	$ -	$ (140,454.16)
Feb-24	$ (103.23)	$ (112,950.39)	$ (796.53)	$ (48,900.63)	$ (1,463.58)	$ -	$ (60.31)	$ (164,274.67)
Mar-24	$ (72.72)	$ (94,002.60)	$ (716.71)	$ (40,189.98)	$ (1,232.87)	$ -	$ -	$ (136,214.89)
Apr-24	$ (78.52)	$ (76,721.66)	$ (660.19)	$ (32,466.60)	$ (821.96)	$ -	$ (319.28)	$ (111,068.20)
May-24	$ (90.70)	$ (39,386.59)	$ (698.74)	$ (16,024.65)	$ (370.48)	$ -	$ (3,138.36)	$ (59,709.51)
Jun-24	$ (149.11)	$ (14,118.10)	$ (629.56)	$ (6,990.35)	$ (131.85)	$ -	$ (5,543.56)	$ (27,562.54)
Jul-24	$ (112.34)	$ (8,251.49)	$ (567.60)	$ (4,712.85)	$ (59.36)	$ -	$ (2,395.75)	$ (16,099.38)
Aug-24	$ (114.82)	$ (7,670.52)	$ (599.76)	$ (4,835.48)	$ (68.23)	$ -	$ (5,800.16)	$ (19,088.98)
Sep-24	$ (162.95)	$ (9,353.93)	$ (596.22)	$ (5,540.37)	$ (83.48)	$ -	$ (4,921.57)	$ (20,658.51)
Oct-24	$ (92.47)	$ (12,260.51)	$ (580.25)	$ (6,748.65)	$ (79.11)	$ -	$ (3,477.73)	$ (23,238.73)
Nov-24	$ (43.15)	$ (22,313.16)	$ (437.78)	$ (8,994.86)	$ (210.90)	$ -	$ (1,402.48)	$ (33,402.34)
Dec-24	$ (58.46)	$ (45,969.16)	$ (398.01)	$ (19,095.20)	$ (504.92)	$ -	$ (890.14)	$ (66,915.89)
TOTAL	**$ (1,158.29)**	**$ (538,884.21)**	**$ (7,598.98)**	**$ (236,836.31)**	**$ (6,260.68)**	**$ -**	**$ (27,949.33)**	**$ (818,687.80)**

Valley Statement No. 6

BEFORE

THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	**:**	
	:	
v.	**:**	**Docket No. R-2025-_____**
	:	
Valley, Energy, Inc.	**:**	

DIRECT TESTIMONY
AND EXHIBITS

OF

CODY CHAPMAN

ON BEHALF OF

VALLEY ENERGY, INC.

APRIL 30, 2025

BEFORE

THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	**:**	
	:	
v.	**:**	**Docket No. R-2025-_____**
	:	
Valley Energy, Inc.	**:**	

DIRECT TESTIMONY OF CODY CHAPMAN
ON BEHALF OF VALLEY ENERGY, INC.

Q. Please state your name and business address.

A. My name is Cody E. Chapman, PE, and my business address is 523 Keystone Avenue, Sayre, Pennsylvania.

Q. By whom are you employed and in what capacity do you serve at Valley Energy, Inc. ("Valley")?

A. I am employed by C&T Enterprises, Inc. ("C&T"), and assigned to Valley as the Vice President of Operations.

Q. Please describe your duties in this capacity.

A. My duties are to organize, direct, and coordinate the operations and engineering functions at Valley, including, but not limited to designing and coordinating all capital projects and managing all pipeline and facility maintenance activities. These duties include technical services functions in accordance with the objectives and policies of the Company, the Pennsylvania Public Utility Commission, the Federal Pipeline Hazardous Materials and Safety Administration's Office of Pipeline Safety, the Federal Occupational Safety and

Health Administration, and other related regulatory procedures. I also advise the President and CEO of the operational aspects of the company.

Q. Please describe your educational and employment background.

A. I attended Pennsylvania State University from 2003 to 2007 and graduated with a Bachelor of Science degree in Civil Engineering. From 2022 to 2024, I attended Youngstown State University and graduated with a Master of Business Administration degree. In 2013, I received licensure as a Professional Engineer from the Pennsylvania State Board of Professional Engineers, Land Surveyors, and Geologists. I worked for Hawk Engineering, PC and JHA Companies prior to joining Valley Energy.

Q. What were your responsibilities with respect to this filing?

A. As the Vice President of Operations, I was responsible for coordinating with Company witness Mr. Gorman and our other witnesses to address the anticipated capital projects and other operational expenses that we will undertake during the Future Test Year and the Fully-Projected Future Test Year. This includes development of the capital budgets and assessing other operational needs such as vehicles.

Q. Have you previously testified before the Pennsylvania Public Utility Commission?

A. Yes. I provided testimony during Valley's 2022 rate case at Docket No. 2022-3032300.

CAPITAL IMPROVEMENTS AND PROJECTS

Q. Please explain the Company's capital and system improvement activities reflected in the historic, future, and fully-projected future test years.

A. Each year, Valley adopts a capital budget and work plan that sets forth our projected capital and system improvements for the next five years. Our capital and system improvements are a combination of activities to extend service to new customers and to replace existing

facilities. Our capital budget projects annual amounts to be devoted to Mains, Services, Meters/Regulators, District Regulator Stations, Gate Stations/Transmission Mains, Structure/Improvements, IT/Office Equipment and Transportation. The 2025 itemized capital budget is attached as Exhibit__(CC-1), while the five-year capital budget projection from our most recent plan is attached as Exhibit__(CC-2). Our planned work on many of these categories takes into account the results of our Triennial Distribution Integrity Management Plan ("DIMP"), which is attached as Exhibit__(CC-3).

Q. Please explain how the DIMP impacts the Company's capital projects.

A. A good example of the impact of the DIMP is our focus on pressurization. To reduce the risk of over-pressurization of low-pressure distribution systems, the Company is installing redundant relief stations to each of our low-pressure systems. In 2025, we are continuing our multi-year plan to address pressurization, with additional projects identified for 2026. In addition, in 2025 we also plan to replace Aldyl-A vintage plastic equipment on Railroad Street. We hope to have all of the troubled Aldyl-A facilities removed from our system in the next 3 to 5 years.

Q. Valley's 2026 projected capital additions include a substantial increase in activity for Mains and Services. Please explain this increase.

A. Valley's 2026 projected capital additions will include an increase in activity due to several planned projects.

- PennDOT has a scheduled road project that will require Valley to relocate our facilities near a major intersection in Wysox, Pennsylvania.

- Valley will replace approximately two thousand seven hundred fifty feet of Aldyl-A vintage plastic mains and fifty-one Aldyl-A vintage plastic services in a project in Athens Township, Pennsylvania.
- In an effort to reinforce the two systems in Athens Township, Pennsylvania, Valley will extend a main to connect the systems together. This effort will involve crossing Murray Creek with the new main.
- Valley will replace steel mains and seventy-four Aldyl-A vintage plastic and steel tubing services in the east portion of Sayre, Pennsylvania. Due to the large number of services to be replaced on the eight streets and the municipal required paving involved, the project would consist of replacing and relocating the existing steel mains with newer plastic mains.

Q. What steps has Valley undertaken to mitigate Lost and Unaccounted For Gas?

A. The Company performs accelerated leak surveys on leak prone pipe materials, as outlined in the Company's DIMP, such as steel tubing services and vintage plastic (Aldyl-A) mains. In addition, the Company has eliminated all cast iron and bare steel mains, which are susceptible to joint leakage and cracking due to the severe frost conditions experienced in our area. Mitigating these leaks to atmosphere reduces our lost gas.

Another area of influence to Lost and Unaccounted for Gas is meter inaccuracies. To minimize meter inaccuracies, the Company tests large industrial meters at an advanced rate depending on usage. The Company purposely works to maintain a cushion ahead of the

regulated meter testing scheduled to maintain compliance, but also to test meter accuracies to ensure gas is accounted for and billed for in a manner to minimize inaccuracies.

Q. Are the improvements in the historic, future, and fully-projected future test years unique in comparison to Valley's historic practice?

A. We have one unique project in 2025, which is the renovation of the newly-acquired building to serve as a warehousing of construction equipment, work space for construction crews, pressure regulation shop, and training center. Otherwise, our practice and criteria for replacement of pipelines and equipment as they become obsolete or to ensure compliance with safety regulations has not changed in many years; however, we are focusing more closely on pipeline safety improvements as a result of federal requirements and the Company's DIMP.

Q. Please explain how the current inflation and supply chain interruptions are impacting Valley?

A. In 2024 and 2025, we have seen an increase in material costs, inclusion of fuel or tariff surcharges, increase in order minimums, and a decrease in material availability. A sampling of reoccurring purchases from 2023, 2024, and 2025, has shown prices have increased an average of 5.4%, with outliers (not included in our analysis) increasing as much as 28.7%. Some suppliers are instituting minimum order amounts, while others are increasing their existing minimum order requirements. Material lead times have continued to increase. Lead time increases and minimum order requirements necessitate that Valley orders additional material and keeps more material on hand.

Q. Are there any notable types of equipment where Valley is projecting cost increases in excess of normal?

A. Yes. The C&T Information Technology Department has informed us that equipment quotations for computers and other electronic devices are increasing due to the potential tariffs announced by the Federal Government. We are closely monitoring this situation. Valley has been starting to see quotations for products contain a tariff surcharge added in or a notation that invoices may add a tariff surcharge if the manufacturer receives an impact from the tariffs at the time of shipment.

Q. Does the information that you provided to Mr. Gorman reflect the current expected costs for materials and supplies?

A. The information that we provided reflects our current assessment as of March 31, 2025. We conservatively increased most material and supply costs by 3%, with the exception of costs that have a larger historic increase or known projected increases. The costs could change based on general economic conditions and other factors.

Q. Can you address how Valley's capital projects can vary from quarter to quarter?

A. Our service territory is on the New York-Pennsylvania border and can experience cold weather and freezing. Ground frost depth can be a large factor as to capital project constructability. There are certain capital projects that we try to schedule for the months when we expect to have warmer weather. Another factor in scheduling capital projects is varying start dates due to municipal or Pennsylvania Department of Transportation seasonal start and/or stop guidelines. When our employees are not working on capital projects, they undertake other necessary activities that are reflected in O&M expenses.

In addition, there are quarters when Valley's planned capital projects are modified due to third-party requests and activities, such as projects by the local or state road departments

to relocate or repave streets, or projects by other utilities to replace underground facilities within common rights of way. In those situations, we may accelerate or vary our planned projects for the quarter to replace our underground facilities simultaneously. This serves to reduce the inconvenience to the public and to avoid redundant excavation and repaving activities.

Q. Does this conclude your Direct Testimony?

A. Yes.

Valley Statement No. 6

BEFORE

THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	**:**	
	:	
v.	**:**	**Docket No. R-2025-_____**
	:	
Valley, Energy, Inc.	**:**	

DIRECT TESTIMONY
AND EXHIBITS

OF

CODY CHAPMAN

ON BEHALF OF

VALLEY ENERGY, INC.

APRIL 30, 2025

Table 1 – Account Breakdown

366.00	**Gate Station - Structures & Improvements**	$	-
367.00	**Transmission Main**		
369.00	**Gate Station - Meas. & Reg. Station Equip**	$	-
374.00	**Land & Land Rights**	$	-
375.00	**Distribution - Structures & Improvements**		
	Building Renovations - Ferrario Property	$	1,218,878
376.10	**New Mains - Steel**		
	Greens Landing Bridge Attachment - Engineering	$	20,000
	Cathodic Protection	$	23,909
376.20	**New Mains - Plastic**		
	Sheshequin Rd Restoration, Loder St Apts. and Misc.	$	43,599
376.21	**Replacement Mains - Plastic**		
	Railroad St (Aldyl-A)	$	148,151
	Route 220 - Ulster PennDOT Project	$	31,384
378.00	**Distribution - Meas. & Reg. Station Equip**		
	Third & Elizabeth St Station Replacement	$	87,785
	Low Pressure Over Pressure Protection Devices	$	240,708
	Pressure Recorder, Transducers, RTU and Regulators	$	13,373
	Wolcott Hollow Station Heater	$	65,058
380.10	**New Services - Steel**	$	-
380.20	**New Services - Plastic**	$	381,883
	Replacement Services	$	606,637
381.00	**Meters & Meter Installations**	$	96,896
381.20	**AMR - Residential & Commercial**	$	25,899
381.30	**Meter Protection**	$	15,153
383.00	**House Regulator & Installation**	$	6,750
385.00	**Ind. Meas. & Reg. Station Equipment**	$	35,200
385.20	**AMR - Industrial**	$	-
387.00	**Other Equipment**	$	-
390.00	**Structures & Improvements**	$	-
391.10	**Office Furniture & Equipment**	$	6,200
391.30	**Computer Equipment**		
	IT	$	78,050
	GIS	$	69,392
392.10	**Transportation Equipment**	$	80,000
393.00	**Stores Equipment**	$	20,000
394.00	**Tools, Shop & Garage Equipment**		
	Construction Equip.	$	29,250
	Leak Detection Equip.	$	15,200
	Corrosion Equip.	$	14,800
	Line Locating Equip	$	4,000
	Meter Reading Equip	$	5,500
396.00	**Power Operated Equipment**	$	-
397.00	**Communication Equipment**	$	500
108.00	**Retirements**	$	17,686
		TOTAL	**$ 3,401,841**

VALLEY ENERGY CAPITAL BUDGET
FIVE YEAR PROJECTION

	2025	2026	2027	2028	2029
MAINS	$ 267,042	$ 1,232,400	$ 354,074	$ 213,102	$ 597,353
SERVICES	$ 988,520	$ 1,340,432	$ 1,004,272	$ 1,177,104	$ 698,711
METERS/ REGULATORS	$ 179,898	$ 169,723	$ 210,845	$ 200,173	$ 221,034
DISTRICT REGULATOR STATIONS	$ 406,925	$ 244,879	$ 399,937	$ 159,910	$ 158,967
GATE STATIONS/TRANSMISSION MAINS	$ -	$ -	$ -	$ -	$ -
STRUCTURE/ IMPROVEMENTS	$ 1,218,878	$ 457,937	$ -	$ 133,539	$ 103,461
EQUIPMENT &TOOLS	$ 68,750	$ 45,000	$ 45,000	$ 115,000	$ 100,000
IT / OFFICE EQUIPMENT	$ 154,142	$ 125,750	$ 126,485	$ 143,958	$ 132,864
TRANSPORTATION	$ 20,000	$ -	$ -	$ -	$ -
CONTRIBUTION IN AID TO CONSTRUCT	0	0	0	0	0
TOTAL	**$ 3,304,155**	**$ 3,616,121**	**$ 2,140,613**	**$ 2,142,786**	**$ 2,012,390**
MAIN/SERV. RETIREMENT COSTS	$ 17,686	$ 34,287	$ 19,859	$ 21,392	$ 25,265
TOTAL	**$ 3,321,841**	**$ 3,650,408**	**$ 2,160,472**	**$ 2,164,178**	**$ 2,037,655**
CAPITAL LEASE	**$ 80,000**	**$ 100,000**	**$ 50,000**	**$ 175,000**	**$ 280,000**
GRAND TOTAL	**$ 3,401,841**	**$ 3,750,408**	**$ 2,210,472**	**$ 2,339,178**	**$ 2,317,655**

FUTURE YEARS NOTES

2026

Specific costs include:
$458,000 for renovations for training center and storage building
$198,000 for a PennDOY relocation project
$864,000 for replacement of vintage services
$765,000 for vintage main replacement

2027

Specific costs include:
$107,000 for main system reinforcement project
$400,000 for additional over-pressure protection devices and station upgrades
$308,000 for replacement of vintage services
$120,000 for vintage main replacement

2028

Specific costs include:
$164,000 for viontage main replacments
$160,000 for district regulating station upgrades
$766,000 for replacement of vintage services

2029 Specific costs include:
$541,000 for vintage main replacments
$217,000 for replacement of vintage services

I&E Statement No. 1
Witness: Christine Wilson

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

VALLEY ENERGY, INC.

Docket No. R-2025-3054393

Direct Testimony

of

Christine Wilson

Bureau of Investigation & Enforcement

Concerning:

OPERATING AND MAINTENANCE EXPENSES

INCOME TAX EXPENSE

RATE BASE

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INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Christine Wilson, and my business address is Pennsylvania Public Utility Commission, Commonwealth Keystone Building, 400 North Street, Harrisburg, PA 17120.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by the Pennsylvania Public Utility Commission (PUC or Commission) in the Bureau of Investigation & Enforcement (I&E) as a Fixed Utility Financial Analyst Supervisor.

Q. WHAT IS YOUR EDUCATION AND EMPLOYMENT BACKGROUND?

A. An outline of my education and employment is set forth in the attached Appendix A.

Q. PLEASE DESCRIBE I&E'S ROLE IN RATE PROCEEDINGS.

A. I&E is responsible for protecting the public interest in proceedings before the Commission. I&E's analysis in this proceeding is based on its responsibility to represent the public interest. This responsibility requires balancing the interests of ratepayers, the regulated utility, and the regulated community as a whole.

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. The purpose of my direct testimony is to review the base rate filing of Valley Energy, Inc. (Valley or Company) and make recommended adjustments to the Company's proposed operating and maintenance (O&M) expenses and rate base claims for the fully projected future test year (FPFTY) ending December 31, 2026. I also present the overall I&E recommended revenue requirement based on my adjustments and the adjustments of I&E witness D.C. Patel.[1]

Q. DOES YOUR DIRECT TESTIMONY INCLUDE AN EXHIBIT?

A. Yes. I&E Exhibit No. 1 contains schedules that support my direct testimony.

Q. WHAT TEST YEARS IS VALLEY USING IN THIS PROCEEDING?

A. Valley is using the year ended December 31, 2024, as the historic test year (HTY), the year ending December 31, 2025, as the future test year (FTY), and the year ending December 31, 2026, as the FPFTY in this proceeding.[2] The Company indicates that its effective date of new rates is January 30, 2026, while also noting that a Commission-approved settlement between the parties could accelerate the effective date.

[1] I&E Statement No. 2.
[2] Valley Statement No. 1, p. 2.

Q. DO YOU AGREE THAT NEW RATES MAY GO INTO EFFECT PRIOR TO THE JANUARY 30, 2026 EFFECTIVE DATE?

A. To an extent. However, rates should not under any circumstances go into effect prior to the beginning of the FPFTY which is January 1, 2026. This date is the beginning of the twelve-month period on which new rates are based. For this reason, it would be unjust and unreasonable for ratepayers to pay the increase in rates prior to the beginning of the first day of the FPFTY.

Q. WHAT IS VALLEY'S REQUESTED REVENUE INCREASE?

A. Valley is requesting an annual total revenue increase of $1,626,099.[3]

SUMMARY OF RECOMMENDED ADJUSTMENTS

Q. PLEASE SUMMARIZE YOUR RECOMMENDED ADJUSTMENTS.

A. The following table summarizes my recommended adjustments:

[3] Valley Exhibit HSG-1, Schedule C1.

	Valley Claim	I&E Recommended Allowance	I&E Adjustment
O&M Expense Adjustments:			
Rate Case Expense	$92,222	$55,333	($36,889)
Regulatory Commission Expense	$105,514	$47,317	($58,197)
Office Supplies & Expense	$81,390	$64,264	($17,126)
Employee Pension & Benefits Exp.	$10,194	$0	($10,194)
Advertising Expense	$2,098	$0	($2,098)
Dues/Company Memberships	$17,295	$13,726	($3,569)
Property Insurance Expense	$41,699	$35,856	($5,843)
Injuries and Damages Expense	$124,881	$108,946	($15,935)
Total O&M Adjustments			**($149,851)**
	Valley Claim	**I&E Recommended Allowance**	**I&E Adjustment**
Income Tax Exp. Adjustments:			
State Income Tax Expense	$122,024	$53,501	($68,523)
Total Income Tax Adjustments			**($68,523)**
Rate Base Adjustments:			
Unamortized Rate Case Expense	$230,556	$0	($230,556)
Cash Working Capital	$491,679	$472,948	($18,731)
Total Rate Base Adjustments			**($249,287)**

OVERALL I&E POSITION

Q. WHAT IS I&E'S TOTAL RECOMMENDED REVENUE REQUIREMENT?

A. I&E's total recommended revenue requirement for Valley is $7,718,567. This recommended revenue requirement represents an increase of $1,212,076 to

Valley's claimed present rate revenues of $6,506,491. This total recommended allowance incorporates my adjustments made in this direct testimony to O&M expenses and rate base, and those recommended adjustments made in the direct testimony of I&E witness D.C. Patel (I&E Statement No. 2). A calculation of the I&E recommended revenue requirement is shown below:

Valley Energy, Inc.		TABLE I			
R-2025-3054393		INCOME SUMMARY			
	12/31/26	INVESTIGATION & ENFORCEMENT			
	Proforma	[----------			----------]
	Present Rates	Adjustments	Present Rates	Allowances	Proposed
	$	$	$	$	$
Operating Revenue	6,506,491	0	6,506,491	1,212,076	7,718,567
Deductions:					
O&M Expenses	4,080,000	-149,851	3,930,149	11,200	3,941,349
Depreciation	1,542,548	0	1,542,548		1,542,548
Taxes, Other	33,587	0	33,587	0	33,587
Income Taxes:					
Current State	-48,150	11,705	-36,445	89,946	53,501
Current Federal	-38,803	30,356	-8,447	233,295	224,848
Deferred Taxes	0	0	0		0
ITC	0	0	0		0
Total Deductions	5,569,182	-107,790	5,461,392	334,441	5,795,833
Income Available	937,309	107,790	1,045,099	877,635	1,922,734
Rate Base	25,187,466	-249,287	24,938,179	0	24,938,179
Rate of Return	3.72%		4.19%		7.71%

RATE CASE EXPENSE

Q. BRIEFLY DESCRIBE THE NATURE AND TYPES OF EXPENDITURES TYPICALLY ALLOWED AS A PART OF A REGULATED UTILITY'S OVERALL RATE CASE EXPENSE.

A. The nature and types of individual expenditures that comprise a utility's allowable

claim for rate case expense are those directly incurred to compile, present, and defend a utility's request for a base rate increase before the Commission. The actual expenditures and estimated costs typically found in an allowable rate case expense claim include legal fees for outside counsel, fees to outside consultants, and the cost of printing, document assembly, and postage.

Q. HOW HAS THE COMMISSION TRADITIONALLY TREATED RATE CASE EXPENSE FOR RATEMAKING PURPOSES?

A. The Commission has historically stated that it considers prudently incurred rate case expense as an ongoing expense, occurring at irregular intervals, related to the rendering of utility service. The Commission has also cited the importance of considering the subject utility's history regarding the frequency of rate case filings as an essential element to determine the normalized level of rate case expense for ratemaking purposes.[4]

Q. HOW IS THE FREQUENCY OF RATE CASE FILINGS DETERMINED?

A. The frequency is determined by calculating the average number of months between the utility's recent base rate case filings.

[4] "A Guide to Utility Ratemaking," by James H. Cawley and Norman J. Kennard (2018 Edition), p. 112, https://www.puc.pa.gov/General/publications_reports/pdf/Ratemaking_Guide2018.pdf, accessed July 2, 2025.

Q. WHAT IS THE COMPANY'S CLAIM FOR RATE CASE EXPENSE?

A. The Company's FPFTY claim for rate case expense is $92,222.[5]

Q. WHAT IS THE BASIS FOR THE COMPANY'S CLAIM?

A. The Company has estimated its total rate case expense of $276,667 via the breakdown in the filing and is requesting an amortization period of three years (36 months)[6] based on the belief that Valley needs to file rate cases every three years to avoid large rate increases at one time.[7] While the Company states that it is requesting an amortized rate case expense, it states that the choice of terminology (amortization versus normalization) does not affect the schedule.[8]

Q. AS MENTIONED ABOVE, THE COMPANY REFERENCES ITS CLAIM AS AN AMORTIZED EXPENSE. BRIEFLY DISCUSS THE CONCEPT OF AMORTIZATION.

A. Amortization is an accounting procedure that extinguishes an atypical, nonrecurring asset over a predetermined number of years by incrementally charging to expense the total cost over a selected amortization period. For accounting purposes, amortization is typically used for intangible assets. However, for ratemaking purposes, amortization is generally limited to expense

[5] Valley Exhibit HSG-1, Schedule C1-3.
[6] Valley Exhibit HSG-1, Schedule C1-3.
[7] I&E Exhibit No. 1, Schedule 1, p. 1.
[8] I&E Exhibit No. 1, Schedule 1, p. 1.

events that have been authorized for deferral by the Commission through specific company petitions for which a regulatory asset is established. An amortized expense is claimed in subsequent rate cases if there is a remaining unamortized balance. However, when normalizing an expense, a claim for an unrecovered normalized expense should be disallowed if requested in a subsequent rate case.

Q. DO YOU AGREE WITH THE COMPANY'S PROPOSED AMORTIZATION TREATMENT FOR RATE CASE EXPENSE?

A. No. Rate case expense should be normalized for ratemaking purposes.

Q. WHAT IS NORMALIZATION?

A. Normalization is a ratemaking concept used to address the transformation of an operating expense that recurs at irregular intervals into a "normal" annual test year allowance. Normalization specifically addresses the prospective recovery of an ongoing expense that recurs sporadically. Normalized expenses are no different than any other O&M expenses in that the Company has the opportunity to achieve full recovery.

Q. DO YOU AGREE WITH THE COMPANY'S CLAIM FOR RATE CASE EXPENSE?

A. No.

Q. WHAT IS YOUR RECOMMENDATION FOR RATE CASE EXPENSE?

A. I recommend that the Company be required to normalize rate case expense over a period of 60 months resulting in an FPFTY allowance of $55,333 [($276,667 ÷ 60 months) x 12 months], or a reduction of $36,889 ($92,222 - $55,333) to the Company's claim.

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATION?

A. First, as discussed above, I recommend normalization of rate case expense in contrast to the Company's claimed amortization of rate case expense. The Company's rate case expense claim should be normalized instead of amortized because it is an ongoing expense that recurs at irregular intervals, which is the precise circumstance under which normalization treatment of an expense should occur.

Second, I disagree with the Company's claimed 36-month amortization period, because it is not supported by Valley's historic filing frequency. The Company's proposed amortization period fails to properly rely upon the historical data and is speculative in nature. In contrast to the Company's claimed 36-month amortization period, I recommend a 60-month normalization period, which is reasonable and validated by the Company's recent filing history as shown below.[9]

[9] I&E Exhibit No. 1, Schedule 2.

Docket No.	Filing Date	Filing Interval in Months	Average of Three Intervals in Months
R-2025-3054393	4/30/2025	36	60
R-2022-3032300	4/29/2022	34	
R-2019-3008209	7/1/2019	110	
R-2010-2174470	4/30/2010		

The historic filing details shown above produce an average historic filing frequency of 60 months [(36 + 34 + 110) ÷ 3], which supports my recommended normalization period. Valley's claim for rate case expense amortization over 36 months is speculative and should be disallowed both with respect to the time period and the proposed amortization treatment.

Q. HAVE OTHER UTILITIES BEEN GRANTED A NORMALIZATION PERIOD BASED ON SPECULATION OF FUTURE FILINGS, AND IF SO, WHAT WAS THE RESULT?

A. Yes. In 2012, the Commission granted PPL Electric Utilities Corporation (PPL) permission to normalize its rate case expense over a 24-month period based on the expected timing of future base rate case filings.[10] That base rate case was filed on March 30, 2012; however, PPL did not file its next rate case until March 31, 2015, which was 36 months after the 2012 rate case filing. I&E's recommended normalization period in that 2012 proceeding was a 32-month interval based on

[10] *PA PUC v. PPL Electric Utilities Corporation*, Docket No. R-2012-2290597, pp. 47-48 (Order Entered December 28, 2012).

PPL's historic filing frequency.[11] I&E's recommendation in that instance produced a much more accurate result than PPL's stated future intention to file a rate case.

Q. ARE THERE ANY RECENT COMMISSION DECISIONS THAT SUPPORT YOUR RECOMMENDATION FOR A RATE CASE FILING INTERVAL BASED ON HISTORIC FILING FREQUENCY?

A. Yes. The following six cases resulted in the Commission using each company's historic average filing frequency.

First, in a base rate case filed by Emporium Water Company, the Commission adopted I&E's recommended historic filing frequency including I&E's recommended five-year normalization period based on a historic average filing frequency that was rounded down from 64 months.[12]

Second, in a base rate case filed by the City of DuBois, the Commission agreed with I&E's recommendation to use an historic filing frequency and adopted I&E's recommended 64-month normalization period which matched the actual historic filing frequency.[13]

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[11] I&E Statement No. 2, pp. 13-14 at Docket No. R-2012-2290597.

[12] *PA PUC v. Emporium Water Company*, Docket No. R-2014-2402324, Opinion and Order, p. 50 (Order Entered January 28, 2015).

[13] *PA PUC v. City of DuBois - Bureau of Water*, Docket No. R-2016-2554150, Opinion and Order, pp. 65-66 (Order Entered March 28, 2017) and PA PUC v. City of DuBois - Bureau of Water, Docket No. R-2016-2554150, Opinion and Order, p. 13 (Order Entered May 18, 2017).

Third, in a base rate case filed by Columbia Gas of Pennsylvania, Inc., the Commission held that the normalization period should align with the historic data rather than the company's intent to file its next base rate case.[14]

Fourth, in a base rate case filed by PECO Energy Company - Gas Division (PECO), the Commission granted I&E's recommended five-year normalization period rather than PECO's claim based on a three-year period because the Commission determined a normalization period based on actual historic filing frequency is more reliable than future speculation.[15]

Fifth, in a base rate case filed by Philadelphia Gas Works (PGW), the Commission agreed with I&E's recommended 53-month normalization period over PGW's claim based on a three-year period, granting a normalization period based on actual historic filing frequency rather than PGW's future intention to file a rate case.[16]

Finally, in the most recent base rate case filed by the Columbia Water Company, the Commission held that the normalization period should align with the historic filing frequency rather than that company's intent to file its next rate case, and that the intent to file a base rate case does not justify deviating from the Commission's practice of relying on historic filing frequency.[17]

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[14] *PA PUC v. Columbia Gas of Pennsylvania, Inc.*, Docket No. R-2020-3018835, Opinion and Order, pp. 78-79 (Order Entered February 19, 2021).

[15] *PA PUC v. PECO Energy Company (Gas Division)*, Docket No. R-2020-3018929, Opinion and Order, p. 119 (Order Entered June 22, 2021).

[16] *PA PUC v. Philadelphia Gas Works*, Docket No. R-2023-3037933, Opinion and Order, pp. 65-66 (Order Entered November 9, 2023).

[17] *PA PUC v. Columbia Water Company*, Docket No. R-2023-3040258, Opinion and Order, p. 34 (Order Entered January 18, 2024).

Q. GIVEN THESE COMMISSION ORDERS AND THE COMPANY'S FILING HISTORY, IS THE CLAIMED 36-MONTH RECOVERY PERIOD REASONABLE?

A. No. The Company has not demonstrated that it will file its next base rate case within 36 months of filing this rate case.

Q. DO YOU HAVE ANY OTHER ISSUE TO ADDRESS RELATED TO RATE CASE EXPENSE?

A. Yes. The Company improperly claims the unamortized portion of rate case expense in rate base. This issue is addressed in the following section.

UNAMORTIZED RATE CASE EXPENSE IN RATE BASE

Q. WHAT IS INCLUDED IN THE COMPANY'S RATE BASE CLAIM FOR RATE CASE EXPENSE?

A. The Company is claiming what it refers to as the unrecovered portion of rate case expense in rate base.[18]

Q. WHAT IS THE COMPANY'S CLAIM FOR UNAMORTIZED RATE CASE EXPENSE IN RATE BASE?

A. The Company is claiming $230,556 in a regulatory asset.[19]

[18] I&E Exhibit No. 1, Schedule 1, p. 2.
[19] Valley Exhibit HSG-1, Schedule C1-5, p. 2.

Q. WHAT IS THE BASIS FOR THE COMPANY'S CLAIM?

A. The Company opines that it is appropriate to claim this amount in rate base since it is a prepaid expense.[20]

Q. DO YOU AGREE WITH THE COMPANY'S CLAIM?

A. No.

Q. WHAT DO YOU RECOMMEND?

A. I recommend the entire claim of $230,556 be disallowed.

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATION?

A If the Company were allowed to include unamortized rate case expense in rate base along with capturing an amount on the expense side, it would earn a return on and a return of rate case expense. Any allowance for return on an expense, in addition to a return of such an expense, is not an appropriate ratemaking practice. Also, as stated previously, with respect to rate case expense, normalization of such a claim, rather than amortization, is the appropriate ratemaking treatment, and normalization does not include a remaining balance nor allow for a remaining balance to be captured in rate base. Rate case expense represents a routine operating expense which is not extraordinary in nature. As such, rate base

[20] I&E Exhibit No. 1, Schedule 1, p. 2.

treatment of this cost should not be granted.

REGULATORY COMMISSION EXPENSE

Q. WHAT IS INCLUDED IN THE COMPANY'S CLAIM FOR REGULATORY COMMISSION EXPENSE?

A. The Company's claim includes PUC assessments and 2025 rate case expense.[21]

Q. WHAT IS THE COMPANY'S CLAIM FOR REGULATORY COMMISSION EXPENSE?

A. The Company is claiming $105,514.[22]

Q. WHAT IS THE BASIS FOR THE COMPANY'S CLAIM?

A. The Company has included $47,317 for PUC assessments and $58,195 for 2025 rate case expense which produces a total of $105,512.[23] Note, this amount is $2 less than the amount included in the revenue requirement computation of $105,514.[24]

Q. DO YOU AGREE WITH THE COMPANY'S CLAIM?

A. No.

[21] I&E Exhibit No. 1, Schedule 3.
[22] Valley Exhibit HSG-1, Schedule C1-1, p. 2.
[23] I&E Exhibit No. 1, Schedule 3.
[24] Valley Exhibit HSG-1, Schedule C1-1, p. 2.

Q. WHAT DO YOU RECOMMEND?

A. I recommend an allowance of $47,317 or a reduction of $58,197 ($105,514 - $47,317) to the Company's claim.

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATION?

A The PUC assessment claim of $47,317 was supported with a recent assessment invoice,[25] however, the "2025 PA Rate Case Expense" claim included in regulatory commission expense is improper due to rate case expense being claimed elsewhere on Valley Exhibit HSG-1, Schedule C1, line 13, in the amount of $92,222.[26] Therefore, it is necessary to reduce regulatory commission expense by $58,195 for this unsupported additional rate case expense claim.

OFFICE SUPPLIES & EXPENSE

Q. WHAT IS INCLUDED IN OFFICE SUPPLIES & EXPENSE?

A. The Company includes general office supplies, meal expenses, travel and training, and communication equipment in this expense account.[27]

[25] I&E Exhibit No. 1, Schedule 4, p. 2.
[26] See also Valley Exhibit HSG-1, Schedule C1-3 for the rate case expense breakdown producing a claim of $92,222.
[27] I&E Exhibit No. 1, Schedule 5.

Q. WHAT IS THE COMPANY'S CLAIM FOR OFFICE SUPPLIES & EXPENSE?

A. The Company is claiming $81,390.[28]

Q. WHAT IS THE BASIS FOR THE COMPANY'S CLAIM?

A. The Company's claim is based on historic year balances along with an adjustment to travel and training over the 2024 actual amount due to "external pressures on cash flows, as result of unexpected contractor and material costs" and a 3% inflation adjustment between the FTY and FPFTY.[29]

Q. DO YOU AGREE WITH THE COMPANY'S CLAIM?

A. No.

Q. WHAT DO YOU RECOMMEND FOR OFFICE SUPPLIES & EXPENSE?

A. I recommend an allowance of $64,264 or a reduction of $17,126 ($81,390 - $64,264) to the Company's claim.

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATION?

A. My recommendation is based on averaging the most recent three years, 2022, 2023, and 2024 [($62,075 + $74,240 + $56,476) ÷ 3 = $64,264], due to the yearly

[28] Valley Exhibit HSG-1, Schedule C1-1, p. 2.
[29] I&E Exhibit No. 1, Schedule 5.

fluctuation in this expense. This three-year average excludes the unsupported 3% inflation adjustment between the FTY and FPFTY and takes into consideration the yearly fluctuation in each line item reported in response to I&E-RE-10-D.[30]

EMPLOYEE PENSION & BENEFITS EXPENSE

Q. WHAT IS INCLUDED IN EMPLOYEE PENSION & BENEFITS EXPENSE?

A. This account has historically included items such as parties, luncheons, token gifts, etc. along with a single salary survey in 2024.[31] Based on the information provided, it would be more appropriately referred to as employee appreciation expense.

Q. WHAT IS THE COMPANY'S CLAIM FOR EMPLOYEE PENSION & BENEFITS EXPENSE?

A. The Company is claiming $10,194.[32]

Q. WHAT IS THE BASIS FOR THE COMPANY'S CLAIM?

A. The Company's claim is based on an average of 2021 to 2024 expenses with a 3% inflation adjustment between the FTY and FPFTY.[33]

[30] I&E Exhibit No. 1, Schedule 5.
[31] I&E Exhibit No. 1, Schedule 6, p. 2.
[32] Valley Exhibit HSG-1, Schedule C1-1, p. 2.
[33] I&E Exhibit No. 1, Schedule 6, p. 1.

Q. DO YOU AGREE WITH THE COMPANY'S CLAIM?

A. No.

Q. WHAT IS YOUR RECOMMENDATION FOR EMPLOYEE PENSION & BENEFITS EXPENSE?

A. I recommend disallowance of the entire $10,194 claim.

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATION?

A. I recommend disallowance of the entire amount because ratepayers should not be required to fund the Company's choice to offer or sponsor special events for its employees. If leadership is inclined to hold such events, the Company should fund those picnics and celebrations, not the ratepayers. Additionally, the salary survey that is built into the historic average due to a single 2024 survey is not appropriate since it is a historic one-time occurrence and should not be deferred for future recovery given the routine nature of the expense. This recommended disallowance of the entire claim also addresses my concern about a blanket 3% inflation adjustment for this expense category that I disagree with in principle.

<u>ADVERTISING EXPENSE</u>

Q. WHAT IS INCLUDED IN ADVERTISING EXPENSE?

A. This account includes payments to multiple local organizations, many of which

appear to be charities.[34]

Q. WHAT IS THE COMPANY'S CLAIM FOR ADVERTISING EXPENSE?

A. The Company is claiming $2,098.[35]

Q. WHAT IS THE BASIS FOR THE COMPANY'S CLAIM?

A. The Company states that the ads are meant to remind customers of Valley's availability, services, contact information, and safety information, and a 3% inflation adjustment is included for the FPFTY.[36]

Q. DO YOU AGREE WITH THE COMPANY'S CLAIM?

A. No.

Q. WHAT IS YOUR RECOMMENDATION FOR ADVERTISING EXPENSE?

A. I recommend disallowance of the entire $2,098 claim.

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATION?

A. I recommend disallowance of the entire amount because ratepayers should not be required to fund the Company's choice to run such sponsorship ads.[37] If

[34] I&E Exhibit No. 1, Schedule 7, p. 2.
[35] Valley Exhibit HSG-1, Schedule C1-1, p. 2.
[36] I&E Exhibit No. 1, Schedule 7, p. 1.
[37] I&E Exhibit No. 1, Schedule 7, pp. 2-11.

leadership is inclined to make such payments, they should be funded by the Company, not the ratepayers, since the ad examples provided indicate little to no tangible benefit to ratepayers.[38] The ad examples provided also appear redundant, as the same material shown in the ads can be shared on invoices, bill inserts, the Company's website and/or social media accounts. Furthermore, allowing the Company to claim this amount in the revenue requirement is problematic, as the ratepayers have no say in the choice of which charitable organizations should receive such sponsorships. Finally, my recommended disallowance of the entire claim also addresses my concern about a blanket 3% inflation adjustment for this expense category that I disagree with in principle.

DUES/COMPANY MEMBERSHIPS

Q. WHAT IS INCLUDED IN DUES/COMPANY MEMBERSHIPS?

A. This account (#930.22) includes various Company-funded memberships to organizations such as the American Gas Association, Northeast Gas Association,

[38] 66 Pa. C.S. § 1316(a) states:
The [C]ommission shall also disallow as operating expense for ratemaking purposes expenditures for other advertising, unless and only to the extent that the [C]ommission finds that such advertising is reasonable and meets one or more of the following criteria:
(1) Is required by law or regulation.
(2) Is in support of the issuance, marketing, or acquisition of securities or other forms of financing.
(3) Encourages energy independence by promoting the wise development and use of domestic sources of coal, oil, or natural gas and does not promote on method of generating electricity as preferable to other methods of generating electricity.
(4) Provides important information to the public regarding safety, rate changes, means of reducing usage or bills, load management, or energy conservation.
(5) Provides a direct benefit to ratepayers.
(6) Is for the promotion of community service or economic development.

Sayre Rotary Club etc.[39]

Q. WHAT IS THE COMPANY'S CLAIM FOR DUES/COMPANY MEMBERSHIPS?

A. The Company is claiming $17,295.[40]

Q. WHAT IS THE BASIS FOR THE COMPANY'S CLAIM?

A. The Company has provided a list of amounts anticipated to be paid in 2026 for such dues/memberships, but the list of items sums to $15,070 (American Gas Association, $7,534 + Northeast Gas Association, $5,978 + Sayre Rotary Club, $608 + National Fire Protection Association, $205 + Central Bradford Chamber of Commerce, $384 + C&T – Forvis Hotline, $361), and it includes amounts for lobbying.[41]

Additionally, the Company's response to I&E-RE-40-D indicates that 2% increases were applied to the FTY and FPFTY for this expense.[42]

Q. DO YOU AGREE WITH THE COMPANY'S CLAIM?

A. No.

[39] I&E Exhibit No. 1, Schedule 8.
[40] I&E Exhibit No. 1, Schedule 8.
[41] I&E Exhibit No. 1, Schedule 8.
[42] I&E Exhibit No. 1, Schedule 9, p. 2.

Q. WHAT IS YOUR RECOMMENDATION FOR DUES/COMPANY MEMBERSHIPS?

A. I recommend an allowance of $13,726 or a reduction of $3,569 ($17,295 - $13,726) to the Company's claim.

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATION?

A. I recommend disallowance of the Sayre Rotary Club payment of $608, the Central Bradford Chamber of Commerce payment of $384, the lobbying expense for the American Gas Association of $285, and the lobbying expense for the Energy Association of Pennsylvania of $67, which sum to my recommended reduction of $1,344 to the Company "supported" amount of $15,070 listed in response to I&E-RE-23-D. This calculation supports my recommendation of $13,726 ($15,070 - $1,344). The Rotary Club payment and lobby expense amounts should not be funded by ratepayers because they are not necessary for the provision of safe and reliable service to ratepayers.

Finally, the unsupported 2% per year increases for the FTY and FPFTY should be disallowed since there is no basis for these adjustments. My recommended adjustment addresses this indirectly since the Company's supporting detail sums to $15,070 which is less than the $17,295 FPFTY claim.

PROPERTY INSURANCE EXPENSE

Q. WHAT IS THE COMPANY'S CLAIM FOR PROPERTY INSURANCE EXPENSE?

A. The Company is claiming $41,699.[43]

Q. WHAT IS THE BASIS FOR THE COMPANY'S CLAIM?

A. The Company has provided an insurance policy breakdown with prices showing total property insurance of $35,856 for the policy period May 1, 2025 through May 1, 2026.[44] To arrive at the FPFTY claim, the Company states that it inflated its 2025 amount by 12%,[45] representing the average yearly increase between 2021 and 2024, producing an FPFTY claim of $41,699.

Q. DO YOU AGREE WITH THE COMPANY'S CLAIM?

A. No. First, the Company's math is inaccurate, as a 12% increase in the $36,257 FTY claim[46] would be $40,608 ($36,257 x 1.12). I also disagree with the 12% increase for the FPFTY generally.

Q. WHAT IS YOUR RECOMMENDATION FOR PROPERTY INSURANCE?

A. I recommend an allowance of $35,856 or a reduction of $5,843 ($41,699 -

[43] Valley Exhibit HSG-1, Schedule C1-1, p. 2.
[44] I&E Exhibit No. 1, Schedule 10, p. 3.
[45] I&E Exhibit No. 1, Schedule 10, p. 4.
[46] Valley Exhibit HSG-1, Schedule C1-1, p. 2.

$35,856) to the Company's claim.

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATION?

A. My recommendation is based on the known and measurable $2,988 monthly property insurance expense[47] amount annualized over twelve months, producing an FPFTY recommended allowance of $35,856 ($2,988 x 12). While I do see that property insurance has increased from one year to the next since 2021, it just increased significantly in 2025, and that 2025 annualized monthly expense amount is a supportable allowance. The Company asserts that it should increase this expense by 12% due to the historic average increase, however, the Company's response to I&E-RE-40-D indicates that the expense is inflated by 15% after adjustment for the new training facility in the FTY and 15% again in the FPFTY[48] which appears arbitrary and in conflict with the proposed 12% increase. Regardless of the apparent conflicting percentages, the Company has explained in response to I&E-RE-12-D that it shopped around in an effort to reduce insurance costs overall and has added coverage for a recently acquired training center and warehouse.[49] Thus, the historic average 12% increase is speculative at best as a basis for an FPFTY claim. In contrast, the property expense allowance should be based on the known and measurable monthly expense of $2,988 annualized to produce an FPFTY allowance as explained above.

[47] I&E Exhibit No. 1, Schedule 10, p. 4.
[48] I&E Exhibit No. 1, Schedule 9, p. 2.
[49] I&E Exhibit No. 1, Schedule 10, p. 5.

INJURIES AND DAMAGES EXPENSE

Q. WHAT DOES THE COMPANY INCLUDE IN INJURIES AND DAMAGES EXPENSE?

A. According to the response to I&E-RE-40-D, the Company includes injuries and damages expense as well as automobile insurance in Account No. 925, injuries and damages.[50]

Q. WHAT IS THE COMPANY'S CLAIM FOR INJURIES AND DAMAGES EXPENSE?

A. The Company is claiming $124,881.[51]

Q. WHAT IS THE BASIS FOR THE COMPANY'S CLAIM?

A. When asked for support for the total claim of $124,881 in I&E-RE-13-D, the Company only provided an explanation for $75,665 in injuries and damages expense.[52] However, upon reviewing the response to I&E-RE-40-D, it seems clear that the Company also includes its automobile insurance claim on this line in the filing.[53] The Company provided an insurance policy breakdown with prices showing total injuries and damages, including automobile insurance, of $108,946 ($67,379 + $41,567) for the policy period May 1, 2025 through May 1, 2026.[54]

[50] I&E Exhibit No. 1, Schedule 9, p. 2.
[51] Valley Exhibit HSG-1, Schedule C1-1, p. 2.
[52] I&E Exhibit No. 1, Schedule 11, pp. 1-2.
[53] I&E Exhibit No. 1, Schedule 9, p. 2.
[54] I&E Exhibit No. 1, Schedule 10, p. 3.

To arrive at the FPFTY claim, the Company states that it inflated its 2025 amount by 17%[55] representing the average yearly increase between 2021 and 2024. However, in response to I&E-RE-40-D, the Company states that it increased the FTY and FPFTY amounts by 15%.[56]

Q. DO YOU AGREE WITH THE COMPANY'S CLAIM?

A. No. I disagree with both the 15% and 17% increases for the FTY and FPFTY.

Q. WHAT IS YOUR RECOMMENDATION FOR INJURIES AND DAMAGES EXPENSE?

A. I recommend an allowance of $108,946 or a reduction of $15,935 ($124,881 - $108,946) to the Company's claim.

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATION?

A. My recommendation is based on the known and measurable $67,379 amount for injuries and damages and the $41,567 amount for automobile insurance[57] producing an FPFTY recommended allowance of $108,946 ($67,379 + $41,567). Historically, injuries and damages expense has fluctuated between 2021 and 2024,[58] thus, the known and measurable amount for the policy period ending

[55] I&E Exhibit No. 1, Schedule 11, p. 2.
[56] I&E Exhibit No. 1, Schedule 9, p. 2.
[57] I&E Exhibit No. 1, Schedule 10, p. 3.
[58] I&E Exhibit No. 1, Schedule 9, p. 2.

May 1, 2026, provides the most reliable basis for an allowance for injuries and damages expense. The Company has explained in response to I&E-RE-13-D that it has shopped around to reduce the overall insurance costs.[59] For this reason, using a historic average increase is speculative at best as a basis for an FPFTY allowance. In contrast, the amount for the policy period ending May 1, 2026 provides the most reliable basis for an FPFTY allowance.

CASH WORKING CAPITAL

Q. WHAT IS A CWC ALLOWANCE FOR RATEMAKING PURPOSES?

A. CWC includes the amount of funds necessary to operate a utility during the interim period between the rendition of service, including the payment of related expenses, and the receipt of revenue in payment for services rendered by the utility.

Q. HOW DOES THE COMPANY CALCULATE ITS CWC CLAIM?

A. The Company has calculated its CWC claim using the one-eighth method.[60]

Q. DO YOU ACCEPT THE COMPANY'S USE OF THE ONE-EIGHTH METHOD?

A. Yes.

[59] I&E Exhibit No. 1, Schedule 11, p. 1.
[60] Valley Exhibit HSG-1, Schedule C1-5, p. 2.

Q. WHAT IS THE COMPANY'S CLAIM FOR CWC?

A. The Company's claim for CWC is $491,679.[61]

Q. DO YOU AGREE WITH THE COMPANY'S CLAIM?

A. No.

Q. WHAT DO YOU RECOMMEND?

A. I recommend an allowance of $472,948 or reduction of $18,731 ($491,679 - $472,948) to the Company's claim.

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATION?

A. My recommendation includes modification of the Company's claim based on all recommended adjustments to O&M expenses as discussed previously in this direct testimony.

Q. WHY DID YOU MAKE ADJUSTMENTS FOR YOUR O&M RECOMMENDATIONS AS DISCUSSED IN YOUR DIRECT TESTIMONY ABOVE?

A. All recommended O&M adjustments that are cash-based expense claims are included when determining the Company's overall CWC requirement. Therefore,

[61] Valley Exhibit HSG-1, Schedule C1-5, p. 2.

CWC was adjusted to reflect these recommendations.

Q. HOW DID YOU CALCULATE YOUR RECOMMENDATION?

A. The sum of all my recommended O&M adjustments shown in the Summary of Recommended Adjustments table above ($149,851) multiplied by 1/8th (or divided by 8) produces my recommended reduction of $18,731 ($149,851 ÷ 8) to CWC.

Q. IS YOUR RECOMMENDED CWC ALLOWANCE A FINAL RECOMMENDATION?

A. No. All adjustments to the Company's claims for revenues, expenses, taxes, and rate base must be continually brought together in the Administrative Law Judge's Recommended Decision and again in the Commission's Final Order. This process, known as iteration, effectively prevents the determination of a precise calculation until all adjustments have been made to the Company's claim.

STATE INCOME TAX EXPENSE

Q. WHAT IS THE COMPANY'S CLAIM FOR STATE INCOME TAX EXPENSE?

A. The Company's claim for state income tax expense is $122,024.[62]

[62] Valley Exhibit HSG-1 Schedule C1-4.

Q. WHAT IS THE BASIS FOR THE COMPANY'S CLAIM?

A. The Company's state income tax expense claim is based on the existing corporate net income tax rate of 9.99%.[63]

Q. DO YOU AGREE WITH THE COMPANY'S CLAIM?

A. No.

Q. WHAT DO YOU RECOMMEND FOR STATE INCOME TAX EXPENSE?

A. I recommend an allowance of $53,501 or a reduction of $68,523 ($122,024 - $53,501) to the Company's claim.

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATION?

A. On July 8, 2022, Pennsylvania House Bill 1342 was signed into law as Act 53 of 2022. Act 53 lowers the corporate net income tax rate to 7.49% in 2026 (the Company's claimed FPFTY) and decreases the tax rate by 0.5% each year until 2031, when the tax rate will be 4.99%.[64] Therefore, I recommend a Pennsylvania income tax rate of 7.49% to reflect the Pennsylvania corporate income tax rate that will be in effect for the FPFTY. This recommended allowance also incorporates the state income tax effect of my other recommended adjustments and those of I&E witness D.C. Patel.[65]

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[63] Valley Exhibit HSG-1 Schedule C1-4.
[64] I&E Exhibit No. 1, Schedule 12, p. 1.
[65] I&E Statement No. 2.

Q. DOES THE COMPANY AGREE TO CORRECT ITS STATE INCOME TAX EXPENSE CLAIM?

A. Yes. The Company has agreed to correct the state income tax rate in rebuttal testimony.[66]

PENDING ITEMS FOR INFORMATION NOT PROVIDED IN RESPONSE TO DISCOVERY

Q. ARE THERE AREAS WHERE THE COMPANY SAID ITS CLAIMS WERE BASED ON INCORRECT INFORMATION?

A. Yes. In response to numerous discovery questions, Valley indicated that incorrect source documents were used, that the Company is in the process of updating its filing, and that it will send updates to the parties and file updated information with the Commission.[67]

Q. WHICH ACCOUNTS DID VALLEY MENTION IN THOSE RESPONSES THAT MIGHT BE IMPACTED?

A. The responses mentioning potential errors are as follows:

Mains and Services (Account #874)

Ind./Com. Meters, Reg. (Account #876)

Meters & Reg.-City Gate (Account #877)

[66] I&E Exhibit No. 1, Schedule 13.
[67] I&E Exhibit No. 1, Schedule 14.

Meters & House Reg. (Account #878)

Customer Installations (Account #879)

Other Operations Expense (Account #880)

Meas. & Reg. – Gen. (Account #889)

Q. DO YOU HAVE ANY RECOMMENDED ADJUSTMENTS RELATED TO THE COMPANY'S USE OF INCORRECT SOURCE DOCUMENTS FOR THE ABOVE LISTED ACCOUNTS?

A. No. Not currently. However, as of the writing of this direct testimony the Company has not provided updated schedules. Therefore, I reserve my right to make recommended adjustments in surrebuttal testimony in the instant proceeding to the accounts listed above or any other impacted accounts that the Company updates due to the errors Valley has identified.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

Christine S. Wilson
Professional and Educational Background

Experience:

Pennsylvania Public Utility Commission, Harrisburg, Pennsylvania
August 2013 to Present:
Fixed Utility Financial Analyst Supervisor, Bureau of Investigation and Enforcement
Responsible for supervising a team of fixed utility financial analysts and engineers in the analysis and preparation of written and oral testimony in base rate case proceedings, purchased gas cost proceedings, and other proceedings as required.

February 2008 to August 2013:
Fixed Utility Financial Analyst, Bureau of Investigation & Enforcement
Review of operating and maintenance expenses for regulated utilities as a part of the evaluation and recommendation process for utility base rate and purchased gas cost filings, preparing written testimony for cases, and testifying as an expert witness.

Prior Accounting Employment: Approximately fifteen years of performing public, corporate, and nonprofit accounting, in addition to eight years of full-time administrative work.

Education/Certification:

Certified Public Accountant in Pennsylvania, 2000 to 2023 (inactive as of January 1, 2024)

Green Mountain College, Poultney, Vermont
Sustainable MBA Program, four credits earned, 2009 to 2010

Pennsylvania State University, Middletown, Pennsylvania
Bachelor of Science, Professional Accountancy, 1995
(Graduated with distinction)

Utility-Related Trainings & Other Courses/Webinars:

PA Public Utility Commission Rate School, Presenter, January 2022 & February 2024

NARUC Staff Subcommittee on Accounting & Finance, Fall 2021 webinar, October 5-7, 2021

Institute of Public Utilities Accounting and Ratemaking Course (Online)
Michigan State University, East Lansing, Michigan, September 14-16, 2021 (not for credit)

NARUC Staff Subcommittee on Accounting & Finance, Spring 2021 webinar, April 6-8, 2021

NARUC Staff Subcommittee on Accounting & Finance, Fall 2020 webinar, October 21-22, 2020

Christine S. Wilson
Professional and Educational Background

Utility-Related Trainings & Other Courses/Webinars (continued):

S&P Global Essentials of Regulatory Finance, Georgetown University, Washington, DC, October 15-16, 2019

Taxation of Business Entities I: Corporations by University of Illinois, coursera.com, completed October 2019 (not for credit)

Federal Taxation II: Property Transactions of Business Owners and Shareholders by University of Illinois, coursera.com, completed August 2019 (not for credit)

Federal Taxation I: Individuals, Employees, and Sole Proprietorships by University of Illinois, coursera.com, completed July 2019 (not for credit)

Positive Psychology Specialization by University of Pennsylvania, coursera.com, completed May 2019 (not for credit)

Institute of Public Utilities Advanced Regulatory Studies Program
Michigan State University, East Lansing, Michigan, October 1-5, 2018 (not for credit)

Financial Markets (with Honors) by Yale University, coursera.com, completed November 2017 (not for credit)

PA Public Utility Commission Rate Case Training, March 5-6, 2010; October 4-5, 2012

Institute of Public Utilities Advanced Regulatory Studies Program
Michigan State University, East Lansing, Michigan, October 7-10, 2008

NARUC Utility Rate School (conducted by NARUC's Committee on Water and the Institute of Public Utilities, Michigan State University), San Diego, May 11-16, 2008

Testimony Submitted:

R-2024-3046931	PECO Energy Company – Electric Division
R-2024-3047068	FirstEnergy Pennsylvania Electric Company
R-2023-3040153	Greater Hazleton Community Area New Development Organization, Inc. (CAN DO, Inc.)
R-2022-3032764	Leatherstocking Gas Company of PA, LLC

Christine S. Wilson
Professional and Educational Background

Testimony Submitted (continued):

R-2022-3031704	Borough of Ambler – Water Department
R-2021-3027385	Aqua Pennsylvania, Inc. base rate case - Water
R-2021-3027386	Aqua Pennsylvania Wastewater, Inc. base rate case
R-2021-3024750	Duquesne Light Company
P-2020-3022426	PAWC Response to COVID-19 Emergency and Financial Impacts
R-2020-3019369	PA-American Water Company base rate case - Water
R-2020-3019371	PA-American Water Company base rate case - Wastewater
R-2018-3000164	PECO Energy Company – Electric Division
R-2017-2640058	UGI Utilities, Inc. – Electric Division
R-2014-2428745	Metropolitan Edison Company (Met-Ed)
R-2014-2428744	Pennsylvania Power Company (Penn Power)
R-2014-2428743	Pennsylvania Electric Company (Penelec)
R-2014-2428742	West Penn Power Company
R-2014-2402324	Emporium Water Company
R-2014-2406274	Columbia Gas of Pennsylvania, Inc.
R-2013-2397353	Pike County Power & Light (Gas)
R-2013-2372129	Duquesne Light Company
R-2013-2360798	Columbia Water Company
R-2012-2336379	York Water Company
R-2012-2321748	Columbia Gas of Pennsylvania, Inc.
R-2012-2292082	Peoples Natural Gas Company, LLC (1307(f))

Christine S. Wilson
Professional and Educational Background

Testimony Submitted (continued):

R-2012-2285985	Peoples Natural Gas Company, LLC
R-2011-2267958	Aqua Pennsylvania, Inc.
R-2010-2214415	UGI Central Penn Gas, Inc.
R-2010-2201702	Peoples Natural Gas Company, LLC
R-2010-2166214	PAWC Northeast Wastewater Operations
R-2010-2166212	PAWC Coatesville Wastewater Operations
R-2010-2166210	PAWC Claysville Wastewater Operations
R-2010-2166208	PAWC Clarion Wastewater Operations
R-2010-2161694	PPL Electric Utilities Corporation
R-2009-2132019	Aqua Pennsylvania, Inc.
R-2009-2117740	Penn Estates Utilities Inc. - Sewer
R-2009-2117532	Penn Estates Utilities Inc. - Water
M-2009-2123945	PPL Electric Utility Company (Smart Meter Plan)
M-2009-2123944	PECO Energy Company (Smart Meter Plan)
M-2009-2093216	PPL Electric Utility Corporation (EE&C Plan)
M-2009-2093215	PECO Energy Company (EE&C Plan)
R-2008-2079675	UGI Central Penn Gas, Inc.
R-2008-2046518	Pike County Light & Power Company (Electric)
R-2008-2042293	Newtown Artesian Water Company
R-2008-2032689	PAWC Coatesville Wastewater Operations

I&E Exhibit No. 1
Witness: Christine Wilson

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

VALLEY ENERGY, INC.

Docket No. R-2025-3054393

Exhibit to Accompany

the

Direct Testimony

of

Christine Wilson

Bureau of Investigation & Enforcement

Concerning:

OPERATING AND MAINTENANCE EXPENSES

INCOME TAX EXPENSE

RATE BASE

I&E-RE-24-D

Reference Valley Exhibit HSG-1, Schedules C1 and C1-3, concerning rate case expense amortization, provide the following:

A. Detailed breakdown by category of the Company's actual rate case expenses from its prior rate case filing along with the claimed amounts by category.
B. Explain what is meant by "BKD" and the claim of $2,000.
C. Detailed breakdown of the printing, other claim of $10,000 for the current filing.
D. Copies of all current outside service contract agreements for rate case-related services for the current filing.
E. Receipts/invoices for rate case expenses incurred to date for the current filing and provide periodic updates during the duration of this proceeding.
F. Justification for the Company's proposed amortization period of three years.
G. Explanation why the Company references an "amortization period" of three years (as opposed to normalization period).
H. State any claimed unamortized balance that the Company has reflected in rate base or operating expenses and explain the basis for any such inclusion.
I. An estimated breakdown of rate case expense for the current proceeding:
    1. If the case settles prior to rebuttal testimony.
    2. If the case settles after written testimony is prepared by the parties.

Response Provided By:
Edward E. Rogers, President & Chief Executive Officer, Valley Energy, Inc.
Jamie Beale, Vice President/Treasurer, Valley Energy, Inc.
Howard Gorman, President, HSG Group, Inc.

Date: June 2, 2025

Response:

A. Refer to Attachment I&E-RE-24-D Attachment A – 2022 and Current Rate Case filing expense breakdown by category of the Company's actual rate case expenses from its prior rate case filing along with the claimed amounts by category.
B. BKD is the prior name of the Company's auditing firm which is now Forvis Mazars
C. For printing and other expenses are for the printing, postage and handling of notices to the customers and miscellaneous expenses associated with the filing.
D. Refer to I&E-RE-24-D Attachments B1, B2 and B3 for outside service contract agreements for rate case-related services for the current filing.
E. Refer to I&E-RE-24-D Attachment E for invoices incurred to date.
F. The Company believes that three years is the normal time between rate cases. Valley has filed rate cases in 2019, 2022 and now 2025.
G. The Company believes it needs a rate case every three years, especially in order to avoid large increases at one time for its customers. The choice of names, amortization versus normalization, does not affect this schedule.

H. The unrecovered portion of Rate Case expense is included in Rate Base, Schedule C1-5, line 36. This is appropriate, as for any cost the Company prepays, realizes the benefit and charges to expense over an extended period.

I(1) & I(2) Refer to Attachment I&E-RE-24-D Attachment A – 2022 and Current Rate Case filing expense breakdown.

I&E-RE-25-D

Reference Valley Exhibit HSG-1, Schedule C1-3, concerning the claim for rate case expense amortization, provide the following details for the last three base rate cases filed with the Commission:

A. The docket number, date of filing, and the method of resolution (e.g., settlement or litigation); and
B. Requested rate case expense and the actual rate case expense incurred.

Response Provided By: Edward E. Rogers, President & CEO
Valley Energy, Inc.

Date: June 5, 2025

Response:

Docket	Filed	Resolution	Claimed	Incurred
R-2022-3032300	4/29/2022	Settled	$367,077	$157,848
R-2019-3008209	7/1/2019	Litigated	$271,000	$325,773
R-2010-2174470	4/30/2010	Settled	$200,000	$162,237

VALLEY ENERGY, INC.
DOCKET NO. R-2025-3054393

I&E-RE-17-D

Reference Valley Exhibit HSG-1, Schedule C1-1, p. 2 concerning Regulatory Commission Expense (Account 928):

A. Provide a detailed breakdown, supporting documentation, and the basis for HTY 2024, FTY 2025, and FPFTY 2026 claims of $89,218, $99,514, and $105,514 respectively.

B. Explain the reason for the $10,296 ($99,514 - $89,218) increase from the HTY 2024 to FTY 2025 which represents a 12% increase.

C. Explain the reason for the $6,000 ($105,514 - $99,514) increase from the FTY 2025 to FPFTY 2026 which represents a 6% increase.

D. State whether any prior rate case amortizations are included in this FPFTY 2026 claim and if so, state the dollar amount for such claim.

Response Provided By:
Jamie Beale, Vice President/Treasurer, Valley Energy, Inc.

Date: June 2, 2025

Response:

A.

	HTY 2024	FTY 2025	FPFTY 2026
2022 PA Rate Case Expense	$52,195	$52,195	$ -
PUC Assessments	$37,023	$47,317	$ 47,317
2025 PA Rate Case Expense	$ -		$ 58,195
	$89,218	**$99,512**	**$105,512**

B. The increase is due to using the updated PUC assessment amount for the whole year, whereas 2024 only has 8 months at the old rate.

C. The increase is due to increased anticipated expense for the 2025 PA Rate Case.

D. No, no prior rate case amortiztions are included in the FPFTY 2026 claim.

VALLEY ENERGY, INC.
DOCKET NO. R-2025-3054393

I&E-RE-26-D

Reference Valley Exhibit HSG-1, Schedule C1-3 concerning taxes other than income:

A. Provide a copy of the Company's most recent PURTA notification and determination statement in its entirety and indicate the payment status.

B. Indicate why no amount is claimed for PUC/OCA/OSBA assessments, state on which filing schedule/line item the claim is reflected in the revenue requirement (if so), provide the claimed dollar amount, and provide the most recent assessment invoices.

Response Provided By:
Jamie Beale, Vice President/Treasurer, Valley Energy, Inc.

Date: June 2, 2025

Response:

A. See I&E-RE-26-D Attachment A, which has been paid.

B. The claim is reflected on Valley Exhibit HSG-1, Schedule C1-1 Line 42. See I&E-RE-26-D Attachment B.

I&E Exhibit No. 1
Schedule 4
Page 2 of 2

Commonwealth of Pennsylvania

Pennsylvania Public Utility Commission

Harrisburg, PA 17105-3265

GENERAL ASSESSMENTS INVOICE

Invoice Date	Invoice Number
9/6/2024	24-125100
Fiscal Year	
July 1, 2024 to June 30, 2025	

VALLEY ENERGY INC
JAMIE BEALE
523 S KEYSTONE AVENUE
SAYRE PA 18840

- Read carefully Notice of Assessment
- Use return envelope provided
- Make check payable to: **Commonwealth of Pennsylvania**
- If you desire confirmation of receipt, use a mailing service that provides one, such as USPS-Return Receipt, or overnight delivery with receipt confimation

PUC Assessment	$42,048.00
Consumer Advocate Assessment	$4,346.00
SBA Assessment	$923.00
PAY THIS AMOUNT WITHIN 30 DAYS	**$47,317.00**

TO RECEIVE PROPER CREDIT FOR YOUR PAYMENT, REMOVE THE BOTTOM PART OF THIS INVOICE AT THE PERFORATION AND RETURN WITH YOUR REMITTANCE

MAIL PAYMENT TO:

PA DOR
PO BOX 61380
HARRISBURG, PA 17106-1380

FOLD AND CUT HERE

RETURN THIS PORTION WITH YOUR REMITTANCE

VALLEY ENERGY INC
JAMIE BEALE
523 S KEYSTONE AVENUE
SAYRE PA 18840

Invoice Date	Invoice Number
9/6/2024	24-125100
Fiscal Year	
July 1, 2024 to June 30, 2025	

PAY THIS AMOUNT WITHIN 30 DAYS	$47,317.00

240000125100011 090624100042048002000043460030000092300 000047317004

VALLEY ENERGY, INC.
DOCKET NO. R-2025-3054393

I&E-RE-10-D

Reference Valley Exhibit HSG-1, Schedule C1-1, p. 2 concerning Office Supplies & Expense (Account 921):

A. Explain the expense adjustment in detail, going from $56,476 in the HTY 2024 to $79,370 in the FTY 2025, which represents a 41% increase.
B. Explain the expense adjustment in detail, going from $79,370 in FTY 2025 to $81,390 in FPFTY 2026.
C. Provide the expense amounts by year for 2022 and 2023.
D. Provide a yearly detailed breakdown by expense type for the historical amounts in 2022, 2023, 2024, and the claimed amounts for FTY 2025 and FPFTY 2026.

Response Provided By:
Edward E. Rogers, President & Chief Executive Officer, Valley Energy, Inc.

Date: June 2, 2025

Response:

A. through C. The table below presents the detail requested for the amounts in Exhibit HSG-1, Schedule C1-1, page 2 and preceding years.

ACCOUNT 921	2022	2023	2024	2025	2026
GENERAL OFFICE SUPPLIES (00)	13,448	10,761	10,762	12,053	12,053
MEAL EXPENSES (40)	5,155	8,346	8,346	9,132	9,406
TRAVEL AND TRAINING (45)	27,948	38,885	16,808	40,834	42,059
COMMUNICATION EQUIPMENT (50)	15,524	16,248	20,560	17,871	17,352
TOTAL	62,075	74,240	56,476	79,370	81,390

A. The increase from $56,476 in HTY 2024 to $79,370 in FTY 2025 is due primarily to the increased expenses for the travel and training account. Travel and training was reduced in 2024 due to external pressures on cash flows, as result of unexpected contractor and material costs. All training including associated travel and meals are to stay abreast of regulatory requirements, technological advances in industry, best practices, and maintaining industry certifications and licensing.
B. The increase from $79,370 in FTY 2025 to $81,390 in FPFTY 2026 is attributable to an inflation factor of 3% applied.
C. Refer to the table above for 2022 and 2023 expense amounts.
D. Refer to the table above for 2022 through 2026 actual and budgeted expense amounts.

I&E-RE-14-D

Reference Valley Exhibit HSG-1, Schedule C1-1, p. 2 concerning Employee Pension and Benefits (Account 926):

A. Provide a detailed breakdown by type of benefit for the following:
1. HTY 2024 - $6,502.
2. FTY 2025 - $9,898.
3. FPFTY 2026 - $10,194.

B. Provide a similar expense breakdown to those provided in response to Parts A through C above for the years 2022 and 2023.

Response Provided By:
Jamie Beale, Vice President/Treasurer, Valley Energy, Inc.

Date: June 2, 2025

Response:

For A1 and B, see I&E-RE-14-D Attachment A. To develop the budget for FTY 2025, the Company took the average expense of 2021-2024. To develop the budget for FPFTY 2026, the Company added a 3% inflation to the FTY amount.

I&E-RE-14-D Attachment A
Valley Energy, Inc.

	2024
Employee of the Year and Standing Ovation awards	$ 331.80
Award plaques	$ 329.33
Wage & Salary Survey	$ 4,188.67
All Employee Meeting	$ 791.14
Company Picnic	$ 118.59
Employee Shirts	$ 16.37
Employee Luncheon	$ 156.99
PPE	$ 125.77
80th Anniversary Customer giveaway	$ 85.06
80th Anniversary	$ 187.33
Board Room Candy	$ 61.31
Logo Setup Fee Lands End	$ 23.73
Oversight Committee Meeting	$ 45.68
Table cloth for events	$ 40.07
Total	**$ 6,501.84**

	2023
Employee of the Year and Standing Ovation awards	$ 330.92
Award plaques	$ 184.96
Company Picnic	$ 272.57
Employee Luncheon	$ 504.56
Christmas Bonus	$ 6,221.25
Christmas Party	$ 2,275.61
Retirement Gift	$ 330.92
Total	**$ 10,120.79**

	2022
Employee of the Year and Standing Ovation awards	$ 248.19
Award plaques	$ 297.82
Company Picnic	$ 173.73
All Employee Meeting	$ 867.24
Employee Luncheon	$ 1,181.18
Christmas Bonus	$ 6,411.58
Christmas Party	$ 2,126.99
Retirement Gift	$ 270.06
Total	**$ 11,576.79**

I&E-RE-18-D

Reference Valley Exhibit HSG-1, Schedule C1-1, p. 2 and Standard Filing Requirement in Exhibit A, III-25 concerning Advertising (Account 913):

A. Explain why it is appropriate to claim ad payments for organizations such as Towanda Rotary Club, Sayre Little League, St. Agnes School, Lady Redskins Softball, a golf tournament, the Valley Chorus, etc. in base rates.
B. Provide a breakdown of anticipated payments to organizations for FPFTY 2026.
C. Explain how the increases of $59 for FTY 2025 and $41 for FPFTY 2026 were determined.
D. Provide samples of the ads that are claimed in this account.

Response Provided By:
Edward E. Rogers, President & Chief Executive Officer, Valley Energy, Inc.

Date: June 2, 2025

Response:

A. Valley places ads in various publications and guides to remind customers of the Company's availability, services, contact and safety information. It is a normal and recurring cost of operations for all businesses.

B. Refer to I&E-RE-18-D Attachment A, Advertising Breakdown for FPFTY 2026 anticipated payments.

C. The increase was based on a standard 3% annual increase.

D. Refer to I&E-RE-18-D Attachment B, Ad Samples that are claimed for this account.

IE-RE-18 D ATTACHMENT A

Organization	FPFTY 2026
GREATER VALLEY CHAMBER OF COMMERCE	$ 125
ROYAL PUBLISHING	$ 50
TOWANDA ROTARY CLUB	$ 100
COPA KEYSTONE WARDENS	$ 125
SAYRE LITTLE LEAGUE	$ 75
TOWANDA RIVERFEST	$ 250
ST AGNES SCHOOL	$ 50
SPALDING MEMORIAL LIBRARY	$ 105
LADY REDSKINS SOFTBALL	$ 100
ENDLESS MOUNTAINS PREGNANY CARE CENTER	$ 75
KEYSTONE WARDENS	$ 125
VALLEY YOUTH SOCCER ASSOCIATION	$ 175
VALLEY LODGE NO. 153	$ 100
BRADFORD-SULLIVAN COUNTIES OYW	$ 50
(BBBS OF NEPA) GOLF TOURNAMENT	$ 250
DAILY REVIEW	$ 50
THE VALLEY CHORUS	$ 50
ROYAL PUBLISHING	$ 75
GREATER VALLEY CHAMBER OF COMMERCE	$ 175

REVIEWED
SEP 11 2024
BY: L. McLaughlin

Valley Chorus Ad Information

Business: Valley Energy Date:

Address: Sayre PA. Phone:

Ad Size: BC ☐ $30 1/4 Page ☒ $60 1/2 Page ☐ $120 Full Page ☐ $225

I&E Exhibit No. 1
Schedule 7
Page 3 of 11

Information:
- ☒ Same Ad as last year. **NO changes. Page #**_____
- ☐ Same Ad as last year. **Ad size change. Page #** _____
- ☐ Use same Ad. **Adding or deleting some information*. Page #** _____

*Please be specific with what the changes are. We need to know if the entire copy needs to be redone or just a specific part of it.

- ☐ New Information.
- ☐ New Advertiser.
- ☐ Will e-mail information to: **valleychorusmusic@gmail.com**
  (digital files reproduce with better clarity then scanned printouts.)
  Are Christmas decorations ok on ad? No ☐ Yes ☐
  When e-mailing information, put **VALLEY CHORUS AD** in subject line.
  A member will confirm receipt.

PAID: ☐ Yes ☐ Check #_____ ☐ No ☒ Sending Check – Check #_____
☐ Cash Mail to: The Valley Chorus
PO Box 145
'A 18810

Advertiser Signature: _____

_____ ıeet)

_____ ary)

30

VALLEY ENERGY

523 S. Keystone Avenue
P.O. Box 340
Sayre, PA 18840
800/998-4427
570/888-9664
FAX 570/888-6199

Serving the residential, commercial and industrial natural gas needs of the Valley and Towanda area.

Person who collected Ad: _____

White Copy – Must accompany ad to Clare Printing Yellow Copy – Advertiser

I&E Exhibit No. 1
Schedule 7
Page 4 of 11

Sayre Lady Redskins Softball

2023 Season

Sponsorship

___Fence Square Banner (3x5) $250 Annually (Riverfront Ball Park)

___Fence Square Banner (3x5) $450 Annually (Riverfront Ball Park & Snyder Field)

___Full Size Back Stop Banner $5,000 Annually (Riverfront Ball Park)

___Full Size Back Stop Banner $5,000 Annually (Snyder Field)

X Name on Sponsorship Banner $100 Annually displayed at every game

___Donation

Make checks payable to: Lady Redskins Softball,

Sayre High School 331 West Lockhart st Sayre PA 18840

Contact Name: Kathy McCutcheon

Contact Phone: 570-888-9664 Ext: 5231

Contact Email Address: kathym@ctenterprises.org

Company Name: Valley Energy

Email Logo, Slogan, or Contact Info for Banner to:

~~**davidsonsheatingandair@hotmail.com**~~
davidsonsheatingandair@hotmail.com

Thanks for Your Support!

I&E Exhibit No. 1
Schedule 7
Page 5 of 11

WINE & BEER FESTIVAL
www.toasttotowanda.com

February 14, 2024

I&E Exhibit No. 1
Schedule 7
Page 6 of 11

Kathy McCutcheon
Valley Energy
PO Box 340
Sayre, PA 18840

Dear Kathy,

The Towanda Rotary Club is hosting the **Ninth Annual Rotary Wine & Beer Festival** to benefit the Bradford County YMCA on Saturday, May 18th from 12:00 P.M. – 5:00 P.M. at *Mountaineer Park, 117 Thrasher Lane, Monroeton, PA 18832.* We have been ever so grateful for your support of this event in past years and hope you will continue your generosity this year.

In addition to featuring several of our region's wineries, breweries and even a couple of distilleries, we will have a nice variety of local vendors. There will be food stands and food trucks, plus live entertainment from local fan favorite Uncle Stosh's, DJ Ben Jammin – Kim and Jimmy, as well as the talented Logan Route performing. New this year joining us will be the McNett Country Band, featuring square dancing.

The YMCA is an inclusive organization of men, women and children joined together by a shared commitment to Youth Development, promoting Healthy Living and fostering a sense of Social Responsibility. Strengthening the community is our cause. Financial assistance ensures that the YMCA is available to ALL residents of our community. We rely on the generosity of our donors, volunteers, members, and partners to give the additional financial support that will enable the YMCA to make meaningful impact in the community we serve.

Therefore, we are reaching out again this year for sponsors for this worthwhile community event, which has been remarkably successful. Please review the sponsorship levels on the attached form. We are offering **4** free tickets to gold sponsors, **2** tickets to silver sponsors, and **1** to bronze level sponsors. **All sponsors names/logos will be displayed on the WOW website, Instagram, FACEBOOK page and Event Page as well as a sponsor board proudly displayed at the event. The level of displayed ads depends on the level of sponsorship, with Gold receiving the most advertising.** We thank you in advance for your generosity.

Sincerely,

Val

Valerie Miller
YMCA Advisory Board Member

REVIEWED
FEB 20 2024
BY: K. McCutcheon

A TOAST to TOWANDA
WINE & BEER FESTIVAL
www.toasttotowanda.com

9th ANNUAL TOWANDA ROTARY WINE & BEER FESTIVAL

May 18, 2024 12:00p.m. – 5:00 p.m.

Mountaineer Park
65 Thrasher Lane
Monroeton, PA 18832

SPONSORSHIP OPPORTUNITIES

Gold Level	**(4 tickets)**	**$500**	____
[illegible]	**(2 tickets)**	**$250**	____
Bronze Level	**(1 ticket)**	**$100**	X

Sponsor Name: Valley Energy

Sponsor Contact: Kathy McCutcheon

Sponsor Address: 523 S. Keystone Ave Sayre

Please contact Valerie Miller @570-265-2101 x4019 or email vmiller@tsd.k12.pa.us with questions. **Please send electronic logo file also, to the email above.**

Please return completed sponsorship form with a check made payable to **The Towanda Rotary Club** to:

Wine & Beer Festival
Valerie Miller
410 State Street
Towanda, PA 18848

I&E Exhibit No. 1
Schedule 7
Page 8 of 11

VALLEY ENERGY
523 S. Keystone Avenue, P.O. Box 340, Sayre, PA 18840
800/998-4427 • 570/888-9664 • FAX 570/888-6199

Serving the residential, commercial and industrial natural gas needs of the Valley and Towanda area.

COPY
March 2024

BUSINESS SPONSOR FORM

for

"NEWSIES JR."

I&E Exhibit No. 1
Schedule 7
Page 9 of 11

BUSINESS NAME: Valley Energy

CONTACT PERSON: Kathy McCutcheon

CONTACT EMAIL ADDRESS: kathym@ctenterprises.org

SPONSOR LEVEL:

- ☐ GALAXY $100
- ☐ CONSTELLATION $75
- ☒ STAR $50
- ☐ SPARKLE $25

PLEASE MAKE CHECKS PAYABLE TO "ST. AGNES SCHOOL"

Mail to:

ST. AGNES SCHOOL
102 THIRD STREET
TOWANDA, PA 18848
ATTN: JESSICA BUNDLE

IF YOU WOULD LIKE TO SUPPLY YOUR OWN AD FOR OUR FACEBOOK PAGE, PLEASE EMAIL A JPEG, PNG, OR PDF TO:
JESSICA.BUNDLE@STAGNESELEM.COM

Thank You!

Saint Agnes School
102 Third Street
Towanda, PA 18848
(570) 265-6803 ✦ (570) 265-3065 Fax
info@stagneselem.com E-mail
www.stagneselem.com Website

DIOCESE OF SCRANTON
HOLY CROSS SCHOOL
SYSTEM

Holy Cross
High School
Scranton/Dunmore

All Saints
Academy
Scranton

Epiphany
Elementary School
Sayre

LaSalle
Academy
Jessup/Dickson City

Our Lady of Peace
Elementary School
Clarks Green

Saint Agnes
Elementary School
Towanda

Saint Clare/
Saint Paul
Elementary School
Scranton

Saint Mary of Mt. Carmel
Elementary School
Dunmore

March 6, 2024

I&E Exhibit No. 1
Schedule 7
Page 10 of 11

Dear Business Owner,

We are thrilled to once again be able to present a musical theatre production for the public! This year's show will be "Newsies Jr.," which is based on the real-life newies' strike of 1899. The New York newsies – boys and girls who sold newspapers on the street – went up against two powerful newspaper publishers to fight for the chance to earn a livable wage. Our performances are scheduled for April 19th & 20th at 7pm at the historic Keystone Theatre in downtown Towanda, with students in Kindergarten through sixth grade participating!

This year marks our twenty-first school musical, and we hope to once again perform for a packed house (approximately 1,000 attendees over both evenings). We ask that you please consider donating to our sponsorship program, which includes a listing in the program booklet, PLUS an ad on our school's Facebook page beginning on April 1st! The sponsor categories will be as follows:

GALAXY SPONSOR
$100

CONSTELLATION SPONSOR
$75

STAR SPONSOR
$50

SPARKLE SPONSOR
$25

You may supply your own JPEG, PNG or PDF for the Facebook page post, or we can make one for you, which will include your business name and contact information!

We are a non-profit school, part of the Diocese of Scranton's Catholic Schools System, and a 501(c)3 business entity. Your donation would be tax deductible, and we will gladly email or mail a donation receipt to you.

Thank you for your time, and we hope to see you at the show!

Sincerely,

Jessica L Bundle

St. Agnes School Administrative Assistant & Musical Director

I&E Exhibit No. 1
Schedule 7
Page 11 of 11

VALLEY ENERGY
523 S. Keystone Avenue, P.O. Box 340, Sayre, PA 18840
800/998-4427 • 570/888-9664 • FAX 570/888-6199

Serving the residential, commercial, and industrial natural gas needs of the Valley and Towanda area.

811 Know what's **below.** **Call** before you dig.

VALLEY ENERGY, INC.
DOCKET NO. R-2025-3054393

I&E-RE-23-D

Reference Valley Standard Filing Requirement in Exhibit A, III-27 concerning Dues/Company Memberships (Account 930.22):

A. Explain why it is appropriate to claim dues or memberships for the Sayre Rotary Club.
B. Provide the FPFTY 2026 amount claimed for dues or memberships and the account where that claim is reflected in Valley Exhibit HSG-1, Schedule C1-1.
C. Provide a detailed breakdown by payee for the FPFTY 2026 claim.
D. Confirm whether the Company excluded all portions of lobbying expense from its claim for dues and membership, and if not, provide FPFTY 2026 dollar amounts by payee that relate to any claimed lobbying expenses.

Response Provided By:
Edward E. Rogers, President & Chief Executive Officer, Valley Energy, Inc.

Date: June 2, 2025

Response:

A. The claim for Sayre Rotary Club was erroneously included in account 930.22.
B. The amount claimed for dues and memberships for FPFTY 2026 is included Valley Exhibit HSG-1, Schedule C1-1, page 2 of 2, Line 43, Account 930 in the amount of $17,295.
C. Refer to table for detailed breakdown by payee for the FPFTY 2026.

Ameican Gas Association	$7,534
Northeast Gas Asociation	$5,978
Sayre Rotary Club	$608
National Fire Protection Association	$205
Central Bradford Chamber of Commerce	$384
C&T – Forvis - Hotline	$361

D. Lobbying expense for dues and membership for FPFTY 2026 were not excluded. Dollar amounts by payee that relate to any claimed lobbying expenses are:
American Gas Association - $285
Energy Association of Pennslyvania - $67

VALLEY ENERGY, INC.
DOCKET NO. R-2025-3054393

I&E-RE-40-D

Reference Valley Exhibit HSG-1, Schedule C1-1, pp. 1-2 concerning operating expenses:

A. Provide details on any claimed across-the-board inflation adjustments for direct and/or allocated expenses.

B. Provide the expense line items for the related FTY and FPFTY claims, inflation factors used, and calculations for the inflation adjustments discussed in response to Part A above.

C. Provide a copy of the source used to determine any inflation factors.

Response Provided By:
Edward E. Rogers, President & Chief Executive Officer, Valley Energy, Inc.
Cody Chapman, Vice President of Operations, Valley Energy, Inc.

Date: June 2, 2025

Response:

A. All expense claims are evaluated on a line-by-line basis as part of the budget setting process to evaluate known and expected changes to each. Each expense is reviewed and adjusted by historical data, known increases and/or calculated inflationary factors.

B. Refer to I&E-RE-40-D Attachment A – 2025-2026 Inflation-Adjustment Factors

C. Refer to I&E-RE-40-D Attachments B through J – for historical examples of increases for some of the material and equipment that are included in these accounts in addition to increase notices provided by vendors.

I&E-RE-40-D Attachment A

	Non-Labor Expenses	2021	2022	2023	2024	2025	Basis for Adjustment	2026	Basis for Adjustment
871.45	DISTRIB LOAD DISPATCHING	1,063	5,793	5,935	6,180	6,763	Actual expense (9% increase)	7,101	5% inflation
874.45	MAT & SUP MAINS & SERV EXP	34,996	36,472	35,264	23,767	32,675	4-year average	32,675	no increase
874.5	CALL CENTER EXPENSE	48,835	55,426	68,268	72,342	74,285	3% inflation	76,514	3% inflation
874.99	TOOLS, EQUIPMENT & MAINTENANCE	-	-	11,676	25,045	10,029	Review of expected exp	10,330	3% inflation
875.45	MAT/SUP MEAS & REG STAT EXP	9,425	8,426	13,743	9,236	10,207	4-year average	10,513	3% inflation
876.45	MAT & SUP IND/CM/MTR/REG/MNT	4,795	4,729	4,773	6,318	7,968	Review of previous years increases and projections - 15%	9,164	15% increase
877.45	MAT/SUP CITYGATE MEAS/REG STA	29,048	14,635	13,553	13,387	13,637	3% inflation	14,046	3% inflation
878.45	MAT & SUP MTR/HSE REG EXP	4,024	3,902	914	1,585	1,634	3% inflation	1,683	3% inflation
879.45	MAT/SUP CUST INSTALL EXP	1,800	1,840	1,444	946	920	3% inflation	947	3% inflation
880.45	MAT/SUP OQ TRAINING	4,393	4,903	7,250	21,154	8,526	lowered 2025 projections ($21,154 to $8,278) based reallocation of expenses + 3%	8,782	3% inflation
881.45	RENTS - DISTRIBUTION EXPENSE	4,773	4,529	5,392	5,803	6,222	based on average increase for last 4 years - 7.19%	6,669	7.19%
886.45	MAT/SUP MAINT STRUCTURE/IMPR	1,602	1,596	1,907	21,033	9,176	did not include maint. Expenses that would not be reoccurring and added new expenses for new training facility	9,451	3% inflation
887.45	MAT/SUPP MAINT OF MAIN	20,015	19,818	55,586	31,010	31,010	kept same as 2024	31,940	3% inflation
889.45	MAT/SUP MAINT M&R STAT EQUIP	9,896	9,549	14,115	18,446	18,998	accelerated inspection program started in 2024 - 3% inflation	19,568	3% inflation
890.45	MAT/SUP MAINT M&R INDUST EQUIP	10,406	4,531	2,392	3,610	3,718	accelerated inspection program started in 2024 - 3% inflation	3,830	3% inflation
891.45	MAT/SUP MAINT CITY GATE STAT	1,827	2,473	15,678	2,655	3,323	deductions for non-reoccurring exp. and additional 2-yr maint. expense starting in Oct 2025 to be amortized	7,616	including 2-yr mant exp amortized
892.45	MAT/SUP MAINT OF SERVICES	18,480	11,076	9,761	5,307	5,440	3% inflation	5,604	3% inflation
893.45	MAT/SUPP MAINT MTR & HSE REG	13,564	15,414	12,960	20,042	13,945	4-year average	14,364	3% inflation
902.45	MAT/SUPP METER READING EXP	2,483	1,846	2,208	4,265	3,981	4-year average	4,100	3% inflation
903.25	NISC BILLING	107,070	106,726	110,306	109,746	111,397	$1,650 planned increase	112,891	based on average increase for last 4 years - 1.34%
903.45	MAT/SUP CUST REC/COLLECTIONS	50,321	40,749	41,370	40,327	29,837	lowered 2025 projections based on reallocation of building expenses to 932 account + 3%	30,732	3% inflation
903.55	DOLLAR ENERGY FUND EXPENSES	5,618	917	929	13,735	5,927	projected expense	5,927	no increase
905.45	MAT/SUP MISC CUST ACCT EXP	22,877	19,524	24,352	19,214	21,492	4-year average	21,492	no increase
909.45	INFORMATION/INSTRUCTIONAL EXP	7,633	11,277	12,388	12,402	12,774	3% inflation	13,157	3% inflation
913.45	ADVERTISING EXPENSES	4,409	3,895	2,278	1,998	2,057	3% inflation	2,098	3% inflation
920.45	MAT/SUP ADMINISTRATIVE	644	162	387	66	68	3% inflation	69	3% inflation
921.0	GENERAL OFFICE SUPPLIES & EXP	12,122	13,448	11,885	10,761	12,054	4-year average	12,054	no increase
921.4	MEAL EXPENSES	2,511	5,155	7,894	8,346	9,132	projected expense	9,406	3% inflation
921.45	TRAVEL AND TRAINING	18,552	27,948	38,885	16,810	40,834	projected expense	42,059	3% inflation
921.5	COMMUNICATION EQUIP	11,714	15,524	16,248	20,559	17,350	deductions for non-reoccurring exp.	17,871	3% inflation
923.0	OUTSIDE SERVICES EMPLOYED	19,142	38,027	25,077	23,880	25,452	additional exp for new training facility	26,215	3% inflation
923.25	AUDITOR FEES EXPENSE	29,692	28,834	44,210	40,495	43,735	based on projected 8% increase	47,233	8% inflation
923.45	ATTORNEY FEES EXPENSE	7,433	9,600	2,785	17,020	8,152	removal of non-reoccurring exp ($17,020 to $7,764) +5% inflation	8,560	5% inflation
924.0	PROPERTY INSURANCE EXPENSE	16,358	17,660	20,388	23,202	36,257	addition of training facility and 4-yr average increase - 15%	41,699	15% increase
925.0	INJURIES AND DAMAGES	85,979	69,301	81,926	93,400	108,157	additional new vehicles and 4-yr average increase - 15%	124,381	15% increase
925.1	INSURANCE ST OPENING BONDS	1,160	750	1,141	500	500	no increase	500	no increase
928.0	REGULATORY COMMISSION EXPENSES	122,392	124,564	115,413	89,218	99,514	added rate case expense	105,514	added rate case expense
930.2	MISCELLANEOUS GENERAL EXPENSE	(2,683)	321	507	234	28,363	expenses reallocated from 880 to 930.2 account	30,751	increase based on projected increases
930.22	DUES/COMPANY MEMBERSHIPS	17,490	15,881	8,978	16,378	16,791	2% increase	17,295	2% increase
	DIRECTOR EXPENSE	48,980	52,020	52,642	52,543	58,639	increased monthly stipend and added meetings	57,047	removal of non-reoccurring meeting expenses
930.45	DIRECTOR EXP. - TRAVEL/TRAINING	-	-	-	-	0	no expense	1,309	director training projected
932.45	MAINT GENERAL PLANT	4,289	3,254	8,021	21,814	23,249	reallocation of exp from 903 account	23,946	3% inflation

I&E-RE-12-D

Reference Valley Exhibit HSG-1, Schedule C1-1, p. 2 concerning Property Insurance (Account 924):

A. Provide a detailed breakdown by insurer/property type by year from HTY 2024 ($23,202), FTY 2025 ($36,257), and FPFTY 2026 ($41,699).
B. Provide recent statements or other documentation that support the Company's FPFTY 2026 claim of $41,699.
C. Explain in detail and provide support for the increase from $23,202 in HTY 2024 to $36,257 in FTY 2025 which represents a 56% increase.
D. Explain in detail and provide support for the increase from $36,257 in FTY 2025 to $41,699 in FPFTY 2026 which represents a 15% increase.

Response Provided By:
Edward E. Rogers, President & Chief Executive Officer, Valley Energy, Inc.

Date: June 2, 2025

Response:

Due to escalating insurance costs, the Company explored other options and was able to reduce its overall insurance costs by switching carriers for the effective period of May 1, 2025, to May 1, 2026, from $206,229 to $144,802. Property insurance costs have increased 37% over the past 4 years. Please note that Federated, which provides the property insurance coverage for Citizens' and Wellsboro, does not offer property insurance for natural gas assets.

Property (924) insurance expense for 2025 and 2026 is $31,920 and $38,819 respectively. Refer to I&E-RE-12-D Attachment A - Previous Insurer quote for 2025/2026, I&E-RE-12-D Attachment B - Current Insurance carrier quote for 2025/2026, I&E-RE-12-D Attachment C – Property Insurance Expense, and I&E-RE-12-D Attachment D – Installment Invoice. As noted on Attachment C, a portion of the increases are due to insurance for the recently-acquired training center and warehouse.

VALLEY ENERGY INC
523 KEYSTONE AVE
PO BOX 340
SAYRE PA 18840

POLICY PERIOD
05/01/2025 - 05/01/2026

On behalf of

MCGLYNN & ASSOCIATES
INSURANCE AGENCY, LLC
ED CARLE
3029 Highway 24
Camden AR 71701
Cell: 225-205-0540

and

Markel Insurance Co

This proposal is intended for illustration purposed only. The policy terms and conditions should be reviewed for specific coverages and exclusion

MARKEL INSURANCE CO

PREMIUM SUMMARY

ACCOUNT:

VALLEY ENERGY INC

Property	$34,951.00
Inland Marine	$2,820.00
General Liability	$33,366.00
Auto	$41,567.00
Umbrella	$30,666.00
Total	$143,370.00

Optional Coverages: If you would like to purchase any of the optional coverages the premium amounts shown below will be added to the policy total above.

Terrorism:

Property	$905.00
IM	$100.00
GL	$256.00
UMB	$171.00
Total	$1,432.00

Property (924) $34,951.00
\+ $ 905.00
= $35,856.00 / 12 = $2,988/month

I&D (925) $ 2,820.00
$33,366.00
$30,666.00
$ 100.00
$ 256.00
\+ $ 171.00
= $67,379.00 / 12 = $5,614.92/month

Employment Practices		
EPLI Limit of Liability	$25,000	
EPLI deductible	$2,500	
EPLI w/third party		$211.00

The amounts of insurance quoted is based on our discussion with you. Under the terms of the policy you are responsible for maintaining an adequate amount at all times. Higher limits of liability are available. If you want higher limits than those quoted here, please ask, and we will seek a quotation to satisfy your request. This form is for illustration purposes only. Policy terms and conditions will supersede the above.

Thank You

Ed Carle

Injuries & damages insurance historic expense and percentage increases:

	2021	2022	2023	2024	2025
Expense	16,360	17,660	20,388	23,200	31,920
% Increase		7.9%	15.4%	13.8%	37.6%

12% average increase 2021-2024 (did not inlcude 2025 in average. Higher insurance costs can partially be attributed to purchase of training facilty and increase in coverage amount)

Updated property insurance expense for 2025:

		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Property	924.00	2,004	2,004	2,004	2,004	2,988	2,988	2,988	2,988	2,988	2,988	2,988	2,988	31,920

Updated property insurance projected expense for 2026 which includes a 12% increase for the insurance term:

		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Property	924.00	2,988	2,988	2,988	2,988	3,358	3,358	3,358	3,358	3,358	3,358	3,358	3,358	38,819

Invoice

McGlynn & Associates Insurance Agency, LLC
PO Box 69
Marshfield, MO 65706

Date	Invoice #
5/7/2025	3268

Bill To
Valley Energy, Inc. 523 s Keystone Ave Sayre, PA 18840

I&IE Exhibit No. 1
Schedule 10
Page 5 of 5

Terms
Due on receipt

Description	Rate	Amount
General Liability & Property Installment 2 Policy Total $72,398.00 #AWUP000613 Property (924) $2,988.00 Injuries & Damages (925) $3,045.14	6,033.14	6,033.14
Automobile Liability Installment 2 Policy Total $41,567 #AWUA000613	3,463.90	3,463.90
Umbrella Liability Installment 2 Policy Total $30,837 #AWUE000613 Injuries & Damages (925)	2,569.74	2,569.74
Policy Period 05/01/2025 - 05/01/2026		
Payment Plan - 12 installments		
Please make check payable to: McGlynn & Associates Insurance Agency		

Thank you for your business.
Questions or concerns please call Alvina at (573)298-6539

Total $12,066.78

VALLEY ENERGY, INC.
DOCKET NO. R-2025-3054393

I&E-RE-13-D

Reference Valley Exhibit HSG-1, Schedule C1-1, p. 2 concerning Injuries and Damages (Account 925):

A. Provide detailed support for following expense claims: HTY 2024 ($93,900), FTY 2025 ($108,657), and FPFTY ($124,881).
B. Explain in detail and provide support for the increase from $93,900 in HTY 2024 to $108,657 in FTY 2025 which represents a 16% increase.
C. Explain in detail and provide support for the increase from $108,657 in FTY 2025 to $124,881 in FPFTY 2026 which represents a 15% increase.
D. Provide actual expense amounts by year for 2022 and 2023.

Response Provided By:
Edward E. Rogers, President & Chief Executive Officer, Valley Energy, Inc.

Date: June 2, 2025

Response:

Due to escalating insurance costs, the Company sought competitive quotations and was able to reduce its overall insurance costs by switching carriers for the effective period of May 1, 2025, to May 1, 2026, from $206,229 to $144,802. Injuries & Damages insurance costs have increased 53% over the past 4 years.

Injuries & Damages (925) insurance expense for 2025 and 2026 is $71,338 and $75,665 respectively. Refer to I&E-RE-12-D Attachment A - Previous Insurer quote for 2025/2026, I&E-RE-12-D Attachment B - Current Insurance carrier quote for 2025/2026, I&E-RE-13-D Attachment A – Injuries & Damages Insurance Expense, I&E-RE-12-D Attachment D – Installment Invoice, and I&E-RE-13-D Attachment B – Street Bond Insurance.

Injuries & damages insurance historic expense and percentage increases:

	2021	2022	2023	2024	2025
Expense	58,981	69,301	81,926	93,900	71,338
% Increase		17.5%	18.2%	14.6%	-24.0%

17% average increase 2021-2024

I&E Exhibit No. 1
Schedule 11
Page 2 of 2

Updated damages & injuries insurance expense for 2025:

		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Injuries & Damages	925.00	6,417	6,417	6,417	6,417	5,615	5,615	5,615	5,615	5,615	5,615	5,615	5,615	
Damages	925.00			375	899									
Street Bonds	925.10				750									
Total		6,417	6,417	6,792	8,066	5,615	5,615	5,615	5,615	5,615	5,615	5,615	5,615	72,612
Non-reoccuring Expenses	925.00			(375)	(899)									(1,274)
Total		6,417	6,417	6,417	7,167	5,615	5,615	5,615	5,615	5,615	5,615	5,615	5,615	71,338

Updated dmamages & injuries insurance projected expense for 2026 which includes a 17% increase for the insurance term:

		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Injuries & Damages	925.00	5,615	5,615	5,615	5,615	6,557	6,557	6,557	6,557	6,557	6,557	6,557	6,557	74,915
Street Bonds	925.10				750									750
Total		5,615	5,615	5,615	6,365	6,557	6,557	6,557	6,557	6,557	6,557	6,557	6,557	75,665

KPMG

TaxNewsFlash

United States

No. 2022-193
July 11, 2022

Pennsylvania: Changes to corporate net income tax laws, other tax changes

House Bill 1342 was signed into law in Pennsylvania on July 8, 2022. The bill makes significant changes to the Commonwealth's corporate net income tax laws, as discussed below.

Corporate net income tax rate reduction

The Commonwealth's current corporate net income tax rate is 9.99%, which is one of the highest in the country. House Bill 1342 reduces that rate incrementally to 4.99%. These rate reductions are scheduled to occur automatically and are not contingent on state tax revenues meeting or exceeding specific thresholds.

The rate is first reduced to 8.99% for the 2023 tax year—the tax year beginning on or after January 1, 2023 through December 31, 2023. The rate is further reduced as follows:

- 8.49% for tax year 2024
- 7.99% for tax year 2025
- 7.49% for tax year 2026
- 6.99% for tax year 2027
- 6.49% for tax year 2028
- 5.99% for tax year 2029
- 5.49% for tax year 2030
- 4.99% for tax years beginning January 1, 2031 and thereafter

KPMG observation

Previous corporate net income rate reductions were included in bills that would also have adopted unitary combined reporting. However, unitary combined reporting is not included in this legislation.

Sales factor changes

Under current law, specific sourcing rules apply to receipts from sales of services and receipts from sales of tangible personal property. All other receipts are sourced under the statutory income-producing activity test and

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are included in the Pennsylvania sales factor numerator if the income-producing activity is performed in Pennsylvania, or if a greater proportion of the income-producing activity is performed in Pennsylvania, based on costs of performance. House Bill 1342 adopts comprehensive customer-based sourcing rules for a number of "other" types of receipts, including:

- Gross receipts from the lease or license of intangible property
- Gross receipts from sales of intangibles
- Gross receipts from the sale, redemption, maturity or exchange of securities held by a taxpayer primarily for sale to customers
- Gross receipts related to lending activities involving real property and tangible personal property
- Gross receipts received from interest, fees, and penalties from credit card holders
- Gross receipts received from interest not otherwise addressed in the revised law

Any gross receipts associated with intangible property that are not specifically addressed will be excluded from both the numerator and denominator of the sales factor. The state tax authority is directed to promulgate rules and regulations to implement the new sourcing rules, which are effective for tax years beginning after December 31, 2022.

KPMG observation

There is ongoing litigation in Pennsylvania over the application of the income-producing activity test as applied to service receipts. The *Synthes* case, currently pending before the Pennsylvania Supreme Court, involves the interpretation of the statutory income-producing activity test in years prior to 2014 before the legislature revised the law to provide that service receipts are sourced to the location where the services are delivered. In *Synthes*, the state tax authority and the taxpayer were on the same side and argued that the tax authority's market-based interpretation of the income-producing activity test, which resulted in a refund for Pennsylvania-based taxpayer, was entitled to deference. The Attorney General, however, disagreed that the tax authority's interpretation was entitled to deference. The Commonwealth Court held in favor of the taxpayer and the tax authority, the Attorney General appealed to the Pennsylvania Supreme Court, and oral arguments were held in March 2022. Although *Synthes* involves service receipts, the outcome may be instructive as to application of the income-producing activity test to other types of receipts for years prior to 2023.

Codification of economic nexus standards

House Bill 1342 codifies Corporation Tax Bulletin 2019-04, issued post-*Wayfair*, in which the state tax authority announced that for tax years beginning on or after January 1, 2020, corporations meeting an economic nexus standard would be required to file corporate net income tax returns (unless protected under Public Law 86-272). The bulletin set forth a rebuttable presumption that a corporate taxpayer without a physical presence in Pennsylvania that had $500,000 or more of direct or indirect gross receipts sourced to Pennsylvania from any combination of (1) gross receipts from the sale, rental, lease, or licensing of tangible personal property; (2) gross receipts from the sale of services; or (3) gross receipts from the sale or licensing of intangibles, including franchise agreements, would have a filing responsibility.

Effective for tax years beginning after December 31, 2022, House Bill 1342 codifies the rebuttable presumption that a corporation with $500,000 or more of receipts sourced to Pennsylvania will have substantial nexus with the Commonwealth, despite the lack of a physical presence. However, an exception applies to affiliated entities domiciled in foreign nations that have entered into comprehensive income tax treaties with the United States. The treaties must provide "for the allocation of all categories of income subject to taxation, or the withholding of tax, on royalties, licenses, fees and interest for the prevention of double taxation of the respective nations' residents and the sharing of information."

KPMG observation

It is important to consider the economic nexus standard in conjunction with the revised sourcing rules that apply beginning with the 2023 tax year. A taxpayer that previously sourced receipts under the income-producing

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activity test may not have had the requisite level of receipts sourced to the Commonwealth. However, that may no longer be the case when those receipts are sourced using the new customer-based rules.

Sales and use tax and other tax changes

Effective January 1, 2023, House Bill 1342 requires peer-to-peer car sharing marketplace facilitators (as defined) to collect sales and use tax on facilitated shared vehicle rentals. The up-to-$2 per day fee that applies to vehicle rentals is extended to vehicles rented as part of a peer-to-peer car sharing program. However, the Commonwealth's 2% vehicle rental tax does not apply to a shared vehicle that is rented through a peer-to-peer car sharing program. The bill also extends the computer data center sales tax exemption qualification period from 15 years to 25 years for qualified purchases of equipment installed in the computer data center.

For individual (personal) income tax purposes, effective for tax years beginning after December 31, 2022, the bill conforms the Commonwealth to the section 179 expensing provisions and the section 1031 deferral provisions. A new refundable tax credit is adopted for eligible taxpayers who receive the federal child and dependent care tax credit. Finally, the bill increases the annual cap for the research and development and film production tax credits and makes certain changes to the keystone opportunity zone provisions.

For more information, contact a KPMG State and Local Tax professional:

Mark Balistrieri | mbalistrieri@kpmg.com

Mark Achord | marchord@kpmg.com

kpmg.com/socialmedia

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I&E-RE-27-D

Reference Valley Exhibit HSG-1, Schedule C1-4 concerning income taxes, explain why a state income tax rate of 9.99% is appropriate for FPFTY 2026.

Response Provided By: Howard Gorman, President, HSG Group, Inc.

Date: June 5, 2025

Response:

This was an oversight in preparing the schedules. We will make the appropriate changes when Rebuttal testimony is filed, using the following rate for Pennsylvania Corporate Net Income Tax:

2024 at 8.49%
2025 at 7.99%
2026 at 7.49%

VALLEY ENERGY, INC.
DOCKET NO. R-2025-3054393

I&E-RE-30-D

Reference Valley Exhibit HSG-1, Schedule C1-1, p. 1 concerning Mains and Services (Account 874), explain the following adjustments in detail:

A. Non-labor expense increase from $286,866 ($454,825 - $167,959) in HTY 2024 to $314,210 ($450,488 - $136,278) in FTY 2025 which represents a 10% increase.

B. Non-labor expense increase from $314,210 ($450,488 - $136,278) in FTY 2025 to $387,246 ($580,482 - $193,236) in FPFTY 2026 which represents a 23% increase.

Response Provided By:
Edward E. Rogers, President & Chief Executive Officer, Valley Energy, Inc.

Date: June 2, 2025

Response:

An incorrect source document was inadvertently used for the 2025 expenses in Accounts 874 through 880, 889, 920 and 932. We are in the process of preparing revisions to Exhibit HSG-1 to correct this oversight, which we will send to the parties (and file with the Commission). At this time, we do not anticipate that those revisions will impact the overall rate increase request or the proposed rates by customer class.

Valley will update this response after completion of the revisions.

I&E-RE-31-D

Reference Valley Exhibit HSG-1, Schedule C1-1, p. 1 concerning Ind./Com. Meters, Reg. (Account 876), explain the following adjustments in detail:

A. Non-labor expense decrease from $94,026 ($102,463 - $8,437) in HTY 2024 to $50,979 ($82,518 - $31,539) in FTY 2025.

B. Non-labor expense increase from $50,979 ($82,518 - $31,539) in FTY 2025 to $58,030 ($94,402 - $36,372) in FPFTY 2026 which represents a 14% increase.

Response Provided By:
Edward E. Rogers, President & Chief Executive Officer, Valley Energy Inc.

Date: June 2, 2025

Response:

An incorrect source document was inadvertently used for the 2025 expenses in Accounts 874 through 880, 889, 920 and 932. We are in the process of preparing revisions to Exhibit HSG-1 to correct this oversight, which we will send to the parties (and file with the Commission). At this time, we do not anticipate that those revisions will impact the overall rate increase request or the proposed rates by customer class.

Valley will update this response after completion of the revisions.

I&E-RE-32-D

Reference Valley Exhibit HSG-1, Schedule C1-1, p. 1 concerning Meters & Reg-City Gate (Account 877), explain the negative non-labor expense of $33,221 ($34,460 - $67,681) in HTY 2024.

Response Provided By:
Edward E. Rogers, President & Chief Executive Officer, Valley Energy, Inc.

Date: June 2, 2025

Response:

An incorrect source document was inadvertently used for the 2025 expenses in Accounts 874 through 880, 889, 920 and 932. We are in the process of preparing revisions to Exhibit HSG-1 to correct this oversight, which we will send to the parties (and file with the Commission). At this time, we do not anticipate that those revisions will impact the overall rate increase request or the proposed rates by customer class.

Valley will update this response after completion of the revisions.

I&E-RE-33-D

Reference Valley Exhibit HSG-1, Schedule C1-1, p. 1 concerning Meters & House Reg (Account 878), explain in detail the non-labor expense increase from $84,034 ($144,252 - $60,218) in FTY 2025 to $92,124 ($159,622 - $67,498) in FPFTY 2026 which represents a 10% increase.

Response Provided By:
Edward E. Rogers, President & Chief Executive Officer, Valley Energy, Inc.

Date: June 2, 2025

Response:

An incorrect source document was inadvertently used for the 2025 expenses in Accounts 874 through 880, 889, 920 and 932. We are in the process of preparing revisions to Exhibit HSG-1 to correct this oversight, which we will send to the parties (and file with the Commission). At this time, we do not anticipate that those revisions will impact the overall rate increase request or the proposed rates by customer class.

Valley will update this response after completion of the revisions.

I&E-RE-34-D

Reference Valley Exhibit HSG-1, Schedule C1-1, p. 1 concerning Customer Installations (Account 879), explain the following adjustments in detail:

A. Non-labor expense decrease from $156,078 ($197,343 - $41,265) in HTY 2024 to $100,731 ($173,184 - $72,453) in FTY 2025 which represents a 35% decrease.

B. Non-labor expense increase from $100,731 ($173,184 - $72,453) in FTY 2025 to $109,805 ($190,044 - $80,239) in FPFTY 2026 which represents a 9% increase.

Response Provided By:
Edward E. Rogers, President & Chief Executive Officer, Valley Energy, Inc.

Date: June 2, 2025

Response:

An incorrect source document was inadvertently used for the 2025 expenses in Accounts 874 through 880, 889, 920 and 932. We are in the process of preparing revisions to Exhibit HSG-1 to correct this oversight, which we will send to the parties (and file with the Commission). At this time, we do not anticipate that those revisions will impact the overall rate increase request or the proposed rates by customer class.

Valley will update this response after completion of the revisions.

I&E-RE-35-D

Reference Valley Exhibit HSG-1, Schedule C1-1, p. 1 concerning Other Operation Expense (Account 880), explain the following adjustments in detail:

A. Non-labor expense decrease from $114,706 in HTY 2024 to $33,832 ($54,435 - $20,603) in FTY 2025 which represents a 71% decrease.

B. Non-labor expense increase from $33,832 ($54,435 - $20,603) in FTY 2025 to $42,702 ($70,684 - $27,982) in FPFTY 2026 which represents a 26% increase.

Response Provided By:
Edward E. Rogers, President & Chief Executive Officer, Valley Energy, Inc.

Date: June 2, 2025

Response:

An incorrect source document was inadvertently used for the 2025 expenses in Accounts 874 through 880, 889, 920 and 932. We are in the process of preparing revisions to Exhibit HSG-1 to correct this oversight, which we will send to the parties (and file with the Commission). At this time, we do not anticipate that those revisions will impact the overall rate increase request or the proposed rates by customer class.

Valley will update this response after completion of the revisions.

VALLEY ENERGY, INC.
DOCKET NO. R-2025-3054393

I&E-RE-37-D

Reference Valley Exhibit HSG-1, Schedule C1-1, p. 1 concerning Meas & Reg- Gen (Account 889), explain the following adjustments in detail:

A. Non-labor expense increase from $41,598 ($76,337 - $34,739) in HTY 2024 to $45,311 ($65,654 - $20,343) in FTY 2025 which represents a 9% increase.

B. Non-labor expense decrease from $45,311 ($65,654 - $20,343) in FTY 2025 to $34,568 ($52,603 - $18,035) in FPFTY 2026 which represents a 24% decrease.

Response Provided By:
Edward E. Rogers, President & Chief Executive Officer, Valley Energy, Inc.

Date: June 2, 2025

Response:

An incorrect source document was inadvertently used for the 2025 expenses in Accounts 874 through 880, 889, 920 and 932. We are in the process of preparing revisions to Exhibit HSG-1 to correct this oversight, which we will send to the parties (and file with the Commission). At this time, we do not anticipate that those revisions will impact the overall rate increase request or the proposed rates by customer class.

Valley will update this response after completion of the revisions.

I&E Statement No. 2
Witness: D. C. Patel

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

VALLEY ENERGY, INC.

Docket No. R-2025-3054393

Direct Testimony

of

D. C. Patel

Bureau of Investigation & Enforcement

Concerning:

Rate of Return

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INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is D. C. Patel and my business address is Pennsylvania Public Utility Commission, Commonwealth Keystone Building, 400 North Street, Harrisburg, PA 17120.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by the Pennsylvania Public Utility Commission (Commission) in the Bureau of Investigation & Enforcement (I&E) as a Fixed Utility Financial Analyst.

Q. WHAT IS YOUR EDUCATION AND PROFESSIONAL EXPERIENCE?

A. My educational and professional experience is set forth in the attached Appendix A.

Q. PLEASE DESCRIBE THE ROLE OF I&E IN RATE PROCEEDINGS.

A. I&E is responsible for representing the public interest in rate and other proceedings before the Commission. I&E's analysis in this proceeding is based on its responsibility to represent the public interest. This responsibility requires balancing the interests of ratepayers, the utility company, and the regulated community as a whole.

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. The purpose of my direct testimony is to review the base rate filing of Valley Energy, Inc. (Valley or Company) and make recommendations regarding the Company's rate of return, including capital structure, cost of long-term debt, the cost of equity, and the overall fair rate of return for the fully projected future test year (FPFTY) ending December 31, 2026.

Q. DOES YOUR DIRECT TESTIMONY INCLUDE AN EXHIBIT?

A. Yes. I&E Exhibit No. 2 contains schedules that support my direct testimony.

BACKGROUND

Q. WHAT IS THE GENERAL DEFINITION OF RATE OF RETURN IN THE CONTEXT OF A RATE CASE?

A. Rate of return is one of the components of the revenue requirement formula. Rate of return is the amount of revenue an investment generates in the form of net income. It is typically expressed as a percentage of the amount of an asset base at a particular point in time, which in base rate proceedings, is the projected rate base balance at the end of the test year.

Q. WHAT IS THE REVENUE REQUIREMENT FORMULA?

A. The revenue requirement formula used in base rate cases is as follows:

$$RR = E + D + T + (RB \times ROR)$$

Where:

RR = Revenue Requirement

E = Operating Expenses

D = Depreciation Expense

T = Taxes

RB = Rate Base

ROR = Overall Rate of Return

In the above formula, the rate of return is expressed as a percentage. The calculation of that percentage is independent of the determination of the appropriate rate base value for ratemaking purposes. As such, the appropriate total dollar return is dependent upon the proper computation of the rate of return and the proper valuation of the Company's rate base.

Q. WHAT CONSTITUTES A FAIR AND REASONABLE OVERALL RATE OF RETURN?

A. A fair and reasonable overall rate of return is one that will allow the utility an opportunity to recover those costs prudently incurred by all classes of capital used to finance the rate base during the prospective period in which its rates will be in effect. The Commission has the authority to determine the fair revenue requirement and rate of return, which is an opportunity for the utility to earn, but not a guarantee to earn.

The *Bluefield Water Works & Improvements Co. v. Public Service Comm. of West Virginia,* 262 U.S. 679, 692-93 (1923), and the *Federal Power*

Commission et al v. Hope Natural Gas Co., 320 U.S. 591, 603 (1944) cases set forth the principles that are generally accepted by regulators throughout the country as the appropriate criteria for measuring a fair rate of return:

1. A utility is entitled to a return similar to that being earned by other enterprises with corresponding *similar risks and uncertainties*, but not as high as those earned by highly profitable or speculative ventures.
2. A utility is entitled to a return level reasonably sufficient to assure financial soundness.
3. A utility is entitled to a return sufficient to maintain and support its credit and raise necessary capital.
4. A fair return can change (increase or decrease) along with economic conditions and capital markets.

Q. EXPLAIN HOW THE OVERALL RATE OF RETURN IS TRADITIONALLY CALCULATED IN BASE RATE PROCEEDINGS.

A. In base rate proceedings, the overall rate of return is traditionally calculated using the weighted average cost of capital method. To calculate the weighted average cost of capital, a company's capital structure must first be determined by comparing the percentage of each capitalization component which has financed the rate base to total capital. In Valley's case, the capital components consist of long-term debt and common equity. Next, the effective cost rate of each capital structure component must be determined. The historical component of the debt

cost rate can be computed accurately, and any future debt issuances are based on estimates. The cost rate of common equity is not fixed and is more difficult to measure. Because of this difficulty, a proxy group is used as discussed later in this direct testimony. Then, each capital structure component percentage is multiplied by its corresponding effective cost rate to determine the weighted capital component cost rate. The table in the *"I&E Position"* section below demonstrates the interaction of each capital structure component and its corresponding effective cost rate. Finally, the sum of the weighted cost rates produces the overall rate of return. This overall rate of return is multiplied by the rate base to determine the return portion of a company's revenue requirement.

COMPANY'S RATE OF RETURN CLAIM

Q. WHO IS THE COMPANY'S RATE OF RETURN WITNESS?

A. Dylan W. D'Ascendis is the primary witness addressing the Company's claimed rate of return. Mr. D'Ascendis filed revised testimony and a corresponding revised exhibit on July 2, 2025. Throughout his direct testimony Mr. D'Ascendis provides analysis for the proxy group, cost of common equity, and overall rate of return for Valley (Valley Joint Statement No. 2 and Exhibit (DWD-1)). Mr. Ryan M. Kucan also filed a revised testimony and a corresponding revised exhibit on July 2, 2025. He provides analysis for the ratemaking capital structure and cost of long-term debt (Valley Joint Statement No. 2A and Exhibit (RMK-1)). Additionally, Edward E. Rogers of Valley provides testimony regarding the Company's "management effectiveness" claim for a 5-basis point reward or adder

to the claimed rate of return on common equity (Valley Statement No. 4).

Q. PLEASE SUMMARIZE MR. D'ASCENDIS AND MR. KUCAN'S RECOMMENDATIONS FOR THE COMPANY'S RATE OF RETURN CLAIM.

A. Mr. D'Ascendis and Mr. Kucan recommend the following rate of return for the Company based on the FPFTY ending December 31, 2026 (Valley Joint Statement No. 2, p. 3, lines 12-13, Table 1 and Valley Joint Statement No. 2A, p. 3, lines 15-16 and Exhibit (RMK-1), Schedule RMK-1):

Valley Energy, Inc. Summary of Cost of Capital			
Type of Capital	**Ratio**	**Cost Rate**	**Weighted Cost Rate**
Long-Term Debt	51.06%	5.03%	2.57%
Common Equity	48.94%	11.65%	5.70%
Total	**100.00%**		**8.27%**

I&E POSITION

Q. PLEASE SUMMARIZE YOUR RATE OF RETURN RECOMMENDATION FOR THE COMPANY.

A. I recommend the following rate of return for the Company (I&E Exhibit No. 2, Schedule 1):

I&E Recommendation Valley Energy, Inc. Summary of Cost of Capital			
Type of Capital	**Ratio**	**Cost Rate**	**Weighted Cost Rate**
Long-Term Debt	51.06%	5.03%	2.57%
Common Equity	48.94%	10.51%	5.14%
Total	**100.00%**		**7.71%**

PROXY GROUP

Q. WHAT IS A PROXY GROUP AS USED IN BASE RATE CASES?

A. A proxy group is a set of companies that have similar traits as compared to the subject utility. This group of companies acts as a benchmark for determining the subject utility's rate of return in a base rate case.

Q. WHAT ARE THE REASONS FOR USING A PROXY GROUP?

A. A proxy group's cost of equity is used as a benchmark to satisfy the long-established guideline of utility regulation that seeks to provide the subject utility with the opportunity to earn a return similar to that of companies with corresponding risks and uncertainties.

A proxy group is typically utilized since the use of data exclusively from one company may be less reliable. The lower reliability occurs because the data for one company may be subject to events that can cause short-term anomalies in the marketplace. The rate of return on common equity for a single company could

become distorted in these circumstances and would therefore not be representative of similarly situated companies. Thus, a proxy group has the effect of smoothing out potential anomalies associated with a single company.

Q. WHAT CRITERIA DID YOU USE IN SELECTING YOUR GAS UTILITY PROXY GROUP?

A. The criteria for my proxy group was designed to select companies that are representative of Valley. I applied the following criteria to the Value Line Investment Survey Industry Classification as a "Natural Gas Utility" company group:

1. Fifty percent or more of the company's revenues must be generated from the regulated gas utility industry.
2. The company's stock must be publicly traded.
3. Investment information for the company must be available from more than one source, which must include Value Line.
4. The company must not be currently involved in an announced merger or the target of an acquisition.
5. The company must have four consecutive years of historic earnings data.
6. The company must be operating in a state that has a deregulated gas utility market.

Q. WHAT CRITERIA DID MR. D'ASCENDIS USE IN SELECTING THE COMPANIES THAT FORMULATE THE GAS UTILITY PROXY GROUP?

A. Mr. D'Ascendis applied the following screening criteria in determining the "Gas Utility Proxy Group" (Valley Joint Statement No. 2, pp. 14, lines 7-22 and p. 15, lines 1-2):

1. The company is included in the Natural Gas Utility Group of Value Line's Standard Edition.
2. The company must have 60% or greater of fiscal year 2023 total operating income derived from, or 60% or greater of fiscal year 2023 total assets attributable to regulated gas distribution operations.
3. The company has not publicly announced that it is involved in any major merger or acquisition activity (i.e., one publicly traded utility merging with or acquiring another or any other major development).
4. The company has not cut or omitted common dividends during the five years ended 2023 or through the time of preparation of the testimony.
5. The company must have Value Line and Bloomberg Professional Services adjusted beta coefficients.
6. The company must have positive Value Line five-year dividends per share growth rate projections.
7. The company must have Value Line, Zacks, or S&P Capital IQ consensus five-year earnings per share growth rate projections.

Q. WHAT PROXY GROUP DID YOU USE IN YOUR ANALYSIS?

A. I included the following seven natural gas distribution companies in my proxy group:

Company	Stock Ticker
Atmos Energy Corp.	ATO
Chesapeake Utilities Corp.	CPK
New Jersey Resources Corp.	NJR
NiSource Inc.	NI
Northwest Natural Gas Co.	NWN
One Gas Inc.	OGS
Spire Inc.	SR

Q. WHAT PROXY GROUP DID MR. D'ASCENDIS USE IN HIS ANALYSIS?

A. Mr. D'Ascendis's core proxy group identified as the "Gas Utility Proxy Group" consists of the following seven natural gas distribution companies (Valley Joint Statement No. 2, p. 15, lines 3-5):

Company	Stock Ticker
Atmos Energy Corp.	ATO
New Jersey Resources Corp.	NJR
NiSource Inc.	NI
Northwest Natural Holding Co.	NWN
One Gas Inc.	OGS
Southwest Gas Holdings Inc.	SWX
Spire Inc.	SR

Q. DO YOU AGREE WITH MR. D'ASCENDIS'S GAS UTILITY PROXY GROUP?

A. Not entirely. Mr. D'Ascendis's Gas Utility Proxy Group includes six companies of my proxy group; however, they exclude Chesapeake Utilities Corp. that I include, and they include Southwest Gas Holdings Inc. that I exclude.

Q. PLEASE EXPLAIN WHY YOU EXCLUDED SOUTHWEST GAS HOLDINGS, INC. FROM YOUR PROXY GROUP.

A. I have excluded Southwest Gas Holdings, Inc. from my proxy group as this company did not meet my first criterion that fifty percent or more of the company's revenues must be generated from the regulated gas utility industry. This is important because revenues represent the percentage of cash flow a company receives from each business line related to providing a good or service. If less than fifty percent of revenues come from the regulated gas sector, the company is not comparable to the subject utility and does not provide a similar level of regulated business. Therefore, I did not include Southwest Gas Holdings, Inc. in my proxy group.

Q. WHAT OTHER PROXY GROUP DID MR. D'ASCENDIS USE IN HIS ANALYSIS?

A. Mr. D'Ascendis opine that the purpose of rate regulation is to be a substitute for marketplace competition, and he believes that non-price regulated companies

operating in the competitive marketplace make an excellent proxy as they are comparable in total risk to the Gas Utility Proxy Group because all companies, utility and non-utility, compete for capital in the same markets (Valley Joint Statement No. 2, p. 41, lines 9-16). Therefore, he formulated another proxy group of forty-nine non-utility/unregulated companies, identified as the "Non-price Regulated Proxy Group" and claims that this group is similar in total risk to the Gas Utility Proxy Group measured by beta coefficient (Valley Joint Statement No. 2, p. 41, lines 20-23). Then, he presented a separate cost of equity analysis results using the Discounted Cash Flow (DCF), Capital Asset Pricing Model (CAPM), and Risk Premium (RP) method for the Non-price Regulated Proxy Group in determining the cost of equity for Valley (Valley Joint Statement No. 2, p. 45, lines 9-10, Table 11).

Q. DO YOU AGREE WITH MR. D'ASCENDIS'S NON-PRICE REGULATED PROXY GROUP OR NON-UTILITY GROUP?

A. No. Mr. D'Ascendis argue that because the U.S. Supreme Court did not specify in the Hope Natural Gas and Bluefield Gas Works cases that comparable risk companies must be utilities, non-price regulated companies can also serve as appropriate proxies (Valley Joint Statement No. 2, p. 41, lines 8-9). I disagree with this argument because it misses the Supreme Court's point that a utility is entitled to a return similar to that being earned by other enterprises with corresponding similar risks and uncertainties, but not as high as those earned by

highly profitable or speculative ventures. I disagree with Mr. D'Ascendis's use of a Non-price Regulated Proxy Group and his opinion that all the companies included in this group have similar total risk traits as compared to Valley and his Gas Utility Proxy Group for the reasons discussed below.

Based on Mr. D'Ascendis's proxy group selection criteria, the Non-price Regulated Proxy Group is comprised of forty-nine companies that operate in the competitive and diverse business segments such as consumer products, chemical processing, pharmaceuticals, auto parts distribution, drug distribution, information technology, consumer equipment, medical equipment, insurance, transportation, industrial products manufacturing, and service sectors of the business economy (Valley Exhibit (DWD-1), Schedule DWD-6, p. 4). This group includes large and highly profitable corporations such as Abbott, Inc., Air Products and Chemicals, Inc., Alphabet, Inc., Apple, Inc., Auto Zone, Inc., CVS Health, Hunt (J.B.), Microsoft Corp., Oracle Corp., Pfizer, Inc., UnitedHealth Group, etc. Mr. D'Ascendis chose these companies from a universe of thousands of non-regulated companies operating in different industry sectors. Despite the differences in operating business risk profiles and the highly competitive market conditions for each industry and company, Mr. D'Ascendis opine that the Non-price Regulated Proxy Group companies face comparable total risks similar to the Gas Utility Proxy Group companies.

These non-utility companies with unrelated or entirely dissimilar business segments are simply not comparable to gas distribution utilities in terms of

business risk and financial risk profiles. Natural gas distribution utilities are monopolies that are subject to very little competition, if any at all. Due to this minimal competition, natural gas distribution utilities in general have very low business risk and can maintain higher financial risk profiles by employing more leverage. Conversely, since the companies in Mr. D'Ascendis's Non-price Regulated Proxy Group operate in an unregulated competitive environment with a higher level of business risks and uncertainties, they must maintain lower financial risk profiles by employing a smaller amount of leverage.

Q. DO YOU AGREE WITH MR. D'ASCENDIS'S COST OF EQUITY ANALYSIS RESULTS OF THE NON-PRICE REGULATED PROXY GROUP?

A. No. Since I disagree with Mr. D'Ascendis's Non-price Regulated Proxy Group, I disagree with the Non-price Regulated Proxy Group equity analysis results of 11.92% based on the DCF, CAPM, and RP methods presented for determining an appropriate cost of equity for Valley in this proceeding (Valley Joint Statement No. 2, p. 45, lines 11-13, Table 11). Additionally, I disagree with the cost of equity estimates for Valley based on an indicated cost of equity range that includes equity results of the Non-price Regulated Proxy Group and the Gas Utility Proxy Group (Valley Joint Statement No. 2, p. 5, line 5, Table 4).

I recommend that the Commission consider only the gas distribution utilities group when evaluating Valley's requested return on equity (ROE) in this proceeding.

CAPITAL STRUCTURE

Q. WHAT IS A CAPITAL STRUCTURE?

A. A capital structure represents how a firm has financed its rate base with different sources of funds. The primary sources of funding are long-term debt and common equity. A capital structure may also include preferred stock and/or short-term debt.

Q. WHAT IS THE COMPANY'S CLAIMED CAPITAL STRUCTURE?

A. The Company's claimed capital structure is summarized in the table below (Valley Joint Statement No. 2A, p. 4, lines 9-11 and Valley Exhibit (RMK-1), Schedule RMK-1, p. 1):

VALLEY ENERGY, INC. Projected Capital Structure as on December 31, 2026	
Type of Capital	**Capitalization Ratio**
Long-Term Debt	51.06%
Common Equity	48.94%
Total	**100.00%**

Q. WHAT IS THE BASIS FOR THE COMPANY'S CLAIMED CAPITAL STRUCTURE?

A. Mr. Kucan recommend the use of the capital structure maintained by the Company's parent organization, C&T Enterprises, Inc. (C&T), consisting of 51.06% long-term debt and 48.94% common equity (Valley Joint Statement No. 2A, p. 4, lines 9-11). Mr. Kucan state that Valley's standalone capital structure as of December 31, 2024 contained 69.90% common equity, which is inappropriate for ratemaking purposes because it is not consistent with equity ratios of comparable utilities (Valley Joint Statement No. 2A, p. 4, line 14 and p. 5, lines 1-4). He concludes that Valley's proposed hypothetical capital structure is reasonable to use and is consistent with the range of capital structures maintained by the Gas Utility Proxy Group as shown in Valley Exhibit (RMK-1), Schedule RMK-2, p. 1 (Valley Joint Statement No. 2A, p. 5, lines 10-13).

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE COMPANY'S CAPITAL STRUCTURE?

A. I recommend using the Company's claimed capital structure as presented in the table above.

Q. WHAT IS THE BASIS FOR YOUR CAPITAL STRUCTURE RECOMMENDATION?

A. A capital structure of 50% long-term debt and 50% common equity is optimal

when trying to balance the financial integrity of a utility as well as trying to control costs for ratepayers. However, I recommend using the Company's claimed capital structure as it falls within the range of my proxy group's 2024 (most recently available) capital structures. The most recent five-year average range of my proxy group companies' capital structure ratios are from 39.33% to 57.23% long-term debt and 35.96% to 60.16% common equity, with an overall five-year average of 47.42% long-term debt and 44.73% common equity (I&E Exhibit No. 2, Schedule 2). Additionally, six of seven companies in my proxy group have a capital structure with a common equity ratio of less than 50% for the most recent five-year average (I&E Exhibit No. 2, Schedule 2).

COST OF DEBT

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE COMPANY'S COST OF LONG-TERM DEBT?

A. I recommend using the Company's claimed FPFTY long-term debt cost rate of 5.03% (Valley Joint Statement No. 2A, p. 5, lines 16-19 and Valley Exhibit (RMK-1), Schedule RMK-1, p. 1).

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATION TO USE THE COMPANY'S CLAIMED COST RATE OF LONG-TERM DEBT?

A. The parent company, C&T Enterprises borrows funds from National Cooperatives Services Corporation on behalf of its subsidiaries, Valley and two electric

companies (Citizens' and Wellsboro), which is guaranteed by subsidiaries' assets and stocks (Valley Statement No. 3, p. 12, lines 7-10). The Company's claimed FPFTY cost rate of long-term debt is based on the outstanding long-term debt embedded interest cost of 5.028% as of December 31, 2024 (I&E Exhibit No. 2, Schedule 3, pp. 1-2).

The Company's claimed 5.03% long-term debt cost rate falls within my proxy group's 2024 implied long-term debt cost range of 2.54% to 6.49% (I&E Exhibit No. 2, Schedule 3, p. 3). The Mergent Bond Record shows an average yield of 5.63% (June 2024 through May 2025) for A-rated public utility bond (I&E Exhibit No. 2, Schedule 3, p. 3). Based on this analysis, I believe that the Company's claimed long-term debt cost rate is representative of the gas utility industry.

COST OF COMMON EQUITY

COMMON METHODS

Q. WHAT METHODS ARE COMMONLY PRESENTED BY UTILITIES IN DETERMINING THE COST OF COMMON EQUITY?

A. Four methods commonly presented to estimate the cost of common equity are the DCF, CAPM, RP, and Comparable Earnings (CE) method.

Q. WHAT IS THE THEORETICAL BASIS FOR THE DCF METHOD?

A. The DCF method is the "dividend discount model" of financial theory, which

maintains that the value (price) of any security or commodity is the discounted present value of all future cash flows. The DCF method assumes that investors evaluate stocks in the traditional economic framework, which maintains that the value of a financial asset is determined by its earning power, or its ability to generate future cash flows. The DCF method is also considered a forward-looking model to estimate the cost of common equity.

Q. WHAT IS THE THEORETICAL BASIS FOR THE CAPM?

A. The CAPM describes the relationship of a stock's investment risk and its market rate of return. It identifies the rate of return investors expect so that it is comparable with returns of other stocks of similar risk. This method hypothesizes that the investor-required return on a company's stock is equal to the return on a "risk free" asset plus an equity premium reflecting the company's investment risk. In the CAPM, two types of risk are associated with a stock: (1) firm-specific risk (unsystematic risk); and (2) market risk (systematic risk), which is measured by a firm's beta. The CAPM allows for investors to receive a return only for bearing systematic risk. Unsystematic risk is assumed to be diversified away, and therefore, does not earn a return.

Q. WHAT IS THE THEORETICAL BASIS FOR THE RP METHOD?

A. The theoretical basis for the RP method is a simplified version of the CAPM. The RP method's theory is that common stock is riskier than debt, thus, investors

require a higher expected return on stocks than bonds. In the RP approach, the cost of equity is made up of the cost of debt and a risk premium. While the CAPM uses the market risk premium, it measures the systematic risk of a company or proxy group through the use of beta. The RP method does not measure the specific risk of a company.

Q. WHAT IS THE THEORETICAL BASIS FOR THE CE METHOD?

A. The CE method utilizes the concept of opportunity cost. This means that investors will likely dedicate their capital to the investment offering the highest return with similar risk to alternative investments. Unlike the DCF, CAPM, and the RP methods, the CE method is not market-based and relies upon historic accounting data. Like the RP method, the CE method does not measure the specific risk of a company. The most problematic issue with the CE method is determining what constitutes comparable companies.

I&E RECOMMENDED METHOD TO EMPLOY

Q. WHAT METHOD DO YOU RECOMMEND TO DETERMINE AN APPROPRIATE COST OF COMMON EQUITY FOR VALLEY?

A. I recommend using the DCF method as the primary method to determine the cost of common equity. Additionally, I provide a CAPM analysis to be used as a comparison, not as a check, to the DCF results. The DCF method has the most wide-spread regulatory acceptance, and while the Commission has more recently

based its ROE decisions on a combination of methods, I still recommend primary reliance on the DCF method due to the shortcomings associated with the CAPM method.

Q. PLEASE EXPLAIN WHY YOU CHOSE TO EMPLOY THE DCF TO DETERMINE YOUR RECOMMENDED RETURN ON EQUITY.

A. I recommend using the DCF for a variety of reasons. The DCF is appealing to investors since it is based on the concept that the receipt of dividends in addition to expected appreciation is the total return requirement determined by the market.[1] The use of a growth rate and expected dividend yield are also strengths of the DCF, as this recognizes the time value of money and is forward-looking. The use of the utility's own, or in this case the proxy group's, stock prices and growth rates directly in the calculation also causes the DCF to be industry and company specific. Finally, the current inflationary and economic trends are most certainly reflected in a stock's price, which is used in determining the dividend yield, and the earnings growth rates forecasted by independent professional analysts. Therefore, the DCF contains the most up-to-date projected information of any model and is the superior method for determining the rate of return for the current economic market conditions because it measures the cost of equity directly.

[1] David C. Parcell, "The Cost of Capital – A Practitioner's Guide," 2020 Edition, p. 153.

Q. PLEASE EXPLAIN WHY YOU CHOSE TO USE THE CAPM AS A COMPARISON TO THE DCF IN YOUR ANALYSIS.

A. I have included a CAPM analysis only as a comparison, and not as a basis, for my recommendation because both the CAPM and the DCF include inputs that allow the results to be specific to the utility industry. However, the CAPM is based on the performance of U.S. Treasury bonds and the performance of the capital market as measured through the S&P 500 and is company-specific only through the use of beta. Beta reflects a stock's volatility relative to the overall market, thereby incorporating an industry-specific aspect to the CAPM, but only as a measure of how reactive the industry is compared to the market as a whole. Although changes in the utility industry are more likely to be accurately reflected in the DCF, which uses the companies' actual stock prices, dividends, and forecasted growth rates, I have included the results of my CAPM analysis because changes in the market, whether as a whole or specific to the utility industry, affect the outcome of each method in different ways. I have provided the results of my CAPM analysis only as a comparison, and not as a check, as it has several disadvantages and should not be given comparable weight to the DCF.

Q. EXPLAIN THE DISADVANTAGES OF THE CAPM.

A. The CAPM, and the RP method by virtue of its similarities to the CAPM, give results that indicate to an investor what the equity cost rate should be if current economic and regulatory conditions are the same as those present during the

historical period in which the risk premiums were determined. This is because beta, which is the only company-specific variable in the CAPM model, measures the *historical* volatility of a stock compared to the *historical* overall market return. Reliance on historical values is especially problematic now given relatively recent events that have impacted economic conditions. Although the CAPM and RP results can be useful to investors in making rational buy and sell decisions within their portfolios, the DCF method is the superior method for determining the rate of return for the current economic market and measuring the cost of equity directly. The CAPM and the RP methods are less reliable indicators because they measure the cost of equity indirectly and risk premiums vary depending on the debt and equity being compared. Also, regulators can never be certain that economic and regulatory conditions underlying the historical period during which the risk premiums were calculated are the same today or will be the same in the future.

Q. IS THERE ANY ACADEMIC EVIDENCE THAT QUESTIONS THE CREDIBILITY OF THE CAPM MODEL?

A. Yes. An article, "Market Place; A Study Shakes Confidence in the Volatile-Stock Theory," which appeared in the *New York Times* on February 18, 1992, summarized a CAPM study conducted by professors Eugene F. Fama and Kenneth R. French.[2] Their study examined the importance of beta, CAPM's risk

[2] Berg, Eric N. "Market Place; A Study Shakes Confidence in the Volatile-Stock Theory" *The New York Times*, February 18, 1992: *nytimes.com* Web. March 23, 2016.

factor, in explaining returns on common stock. In CAPM theory, a stock with a higher beta should have a higher expected return. However, they found that the model did not do well in predicting actual returns and suggested the use of more elaborate multi-factor models.

A more recent article, "The Capital Asset Pricing Model: Theory and Evidence," which appeared in the *Journal of Economic Perspectives,* states that "the attraction of the CAPM is that it offers powerful and intuitively pleasing predictions about how to measure risk and the relation between expected return and risk. Unfortunately, the empirical record of the model is poor - poor enough to invalidate the way it is used in applications."[3] As a result, I conclude that the CAPM's relevance to the investment decision making process does not carry over into the regulatory rate setting process.

Q. PLEASE EXPLAIN WHY YOU HAVE CHOSEN TO EXCLUDE THE RP METHOD FROM YOUR ANALYSIS.

A. The RP method is excluded because it is a simplified version of the CAPM and is subject to the same faults explained above. The RP method has a number of underlying assumptions and the most critical one, as well as the most disputed one, is the assumption that the equity risk premium is constant over the time.[4] Most importantly, unlike the CAPM, the RP method does not recognize company-specific risk through beta.

[3] Fama, Eugene F. and French, Kenneth R., "The Capital Asset Pricing Model: Theory and Evidence." *Journal of Economic Perspectives* (2004): Volume 18, Number 3, pp. 25-46.

[4] David C. Parcell, "The Cost of Capital – A Practitioner's Guide," 2020 Edition, pp. 167-168.

Q. EXPLAIN WHY YOU HAVE CHOSEN TO EXCLUDE THE CE METHOD IN YOUR ANALYSIS.

A. The CE method is excluded because the choice of which companies are comparable is highly subjective, and it is debatable whether historic accounting values are representative of the future. Moreover, its historical usage in this regulatory forum has been minimal.

Q. HAVE YOU IDENTIFIED ANY SPECIFIC PROBLEMS WITH THE COMMISSION'S RECENT USE OF THE CAPM METHOD AS A FACTOR IN ESTABLISHING AN ROE?

A. Yes. The Commission indicated in the 2021 Aqua Pennsylvania, Inc. (Aqua) base rate case order that its method "for determining Aqua's ROE shall utilize both I&E's DCF and CAPM methodologies"[5] and that "I&E's DCF and CAPM produce a range of reasonableness for the ROE…",[6] which deviates from prior Commission practice of primarily relying on the DCF. And more recently, the Commission's Columbia Water Company (Columbia Water) base rate case order relied on the results of I&E's DCF and CAPM analyses for determining Columbia Water's ROE.[7]

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5 *Pa. PUC v. Aqua Pennsylvania, Inc.,* Docket Nos. R-2021-3027385 & R-2021-3027386, pp. 154 (Order entered May 16, 2022).

6 *Pa. PUC v. Aqua Pennsylvania, Inc.,* Docket Nos. R-2021-3027385 & R-2021-3027386, pp. 178 (Order entered May 16, 2022).

7 *Pa. PUC v. Columbia Water Company,* Docket No. R-2023-3040258, p. 105 (Order entered January 18, 2024).

In a report issued by Regulatory Research Associates, a group within S&P Global Market Intelligence,[8] Aqua's ROE of 10.00% was stated as being above the national average for water utility base rate cases. The referenced S&P report, which directly reviews Aqua's ROE of 10.00% on the very date the Commission entered its order in Aqua's base rate proceeding demonstrated that the ROE awarded to Aqua was higher than average. Specifically, the S&P report determined that the average ROE for water utility base rate cases that have been completed during the first four months of 2022 was 9.63% and for the twelve months ended April 30, 2022 was 9.53%, each of which were well below the 10.00% ROE authorized by the Commission for Aqua. This demonstrates the unreasonable skewing of results associated with using the CAPM as a ceiling for determining a utility's ROE.

In the Columbia Water order, the Commission noted that I&E's DCF and CAPM produced a range of reasonableness for the ROE from 7.84% to 11.09% and approved an ROE of 9.75% as reasonable and appropriate for that company, which is based upon consideration of a variety of factors such as increasing inflation leading to increases in interest rates and capital costs.[9] I respectfully disagree with the Commission's basis (current inflation and interest rates) for determining Columbia Water's ROE of 9.75%. I have presented and discussed

[8] Regulatory Research Associates, "Commission authorizes management performance bonus for Aqua Pennsylvania," *S&P Global Market Intelligence*, May 16, 2022. CIQ Pro: RRA Regulatory Focus: Commission authorizes management performance bonus for Aqua Pennsylvania (spglobal.com) (Accessed June 10, 2025).

[9] *Pa. PUC v. Columbia Water Company,* Docket No. R-2023-3040258, pp.108-109 (Order entered January 18, 2024).

below the forecasted lower-level inflation rates, and the likelihood that the Federal Reserve will cut interest rates in 2025-2026, which would have the effect of reducing potential inflation and interest rate risks on capital costs during 2026, when Valley's new rates will be in effect.

Additionally, as explained above, the CAPM should not be used as a primary method, and it should only be used as a comparison (not as a check) of the DCF. Also, as demonstrated below, the use of the CAPM in this proceeding would result in a significant burden to ratepayers during a time of increased levels of inflation. Therefore, I disagree with providing the CAPM comparable weight to the DCF method.

Q. PLEASE COMMENT ON CURRENT INFLATION AND INTEREST RATE CONCERNS.

A. First, I cannot dispute the current economic conditions with respect to increased interest rates and government bond yields, however, it is important to note that all companies, including regulated utilities, are impacted by high interest rates. It is my understanding that the Federal Reserve may consider resuming interest rate cuts later this year, which would impact Valley's FPFTY when the new rates will be in effect.[10] At the latest, a new Federal Reserve Chair will be appointed during the FPFTY and will likely be someone who is certainly open to reducing interest

[10] https://www.reuters.com/business/fed-keep-rates-hold-least-until-september-inflation-risks-linger-2025-06-10/ (accessed June 10, 2025).

rates.[11]

Per the recent monthly Blue Chip Financial Forecasts (July 1, 2025),[12] the 2026 inflation rates by two measures are forecasted to be in the range of 2.2% to 2.8% as shown in the table below:

	Q3 2025	Q4 2025	Q1 2026	Q2 2026	Q3 2026	Q4 2026
Consumer Price Index	3.7%	3.2%	2.8%	2.5%	2.4%	2.4%
PCE Price Index	3.5%	3.0%	2.7%	2.4%	2.2%	2.2%

Likely future reductions in interest rates would have the effect of reducing interest rate risks in the capital costs in 2026, when Valley's new rates will be in effect. Lastly, it is important to note that unlike unregulated companies, public utilities may file rate cases to address unforeseen or increased expenses, increases in the costs of borrowing, and equity and/or revenue shortfalls due to changes in market conditions.

SUMMARY OF THE COMPANY'S RESULTS

Q. WHAT ARE THE RESULTS OF THE COMPANY'S COST OF EQUITY ANALYSES?

A. Mr. D'Ascendis applied the DCF, CAPM, and RP methods to Gas Utility Proxy Group in analyzing the Company's cost of equity. Additionally, he applied these

[11] https://www.foxbusiness.com/economy/trump-eyes-cabinet-member-replace-mr-too-late-powell-fed-report (accessed on June 30, 2025).
[12] Blue Chip Financial Forecasts, Vol. 44, No. 7, July 1, 2025, p. 2.

models to Non-price Regulated Proxy Group companies. Then he adjusted analysis results range by applying a size premium adjustment/adder of 1.00% and the management performance adjustment of 0.05% to each of his analysis results to conclude an indicated range of common equity cost rates. Mr. D'Ascendis's equity cost analysis results are summarized in the table below (Valley Joint Statement No. 2, p. 5, line 5, Table 4):

Method/Model	**Gas Utility Proxy Group**
DCF	10.29%
Traditional CAPM	11.12%
Risk Premium	10.86%
Cost of Equity Models Applied to Non-Price Regulated Companies	11.92%

Ultimately, Mr. D'Ascendis concludes a cost of equity range of 10.29% -11.92% before adjustments and 11.34% - 12.97% after positive adjustments (size premium adjustment of 1.00% and management performance adder of 0.05%) and recommend an 11.65% cost of equity for Valley (Valley Joint Statement No. 2, p. 5, lines 6-12 and p. 6, lines 1-5). Based on this cost of equity range, he recommends a 11.65% return on common equity for Valley and opines that it is reasonable and conservative (Valley Joint Statement No. 2, p. 6, lines 6-8 and p. 52, lines 19-20 and p. 53, lines 1-2).

I&E RECOMMENDATION

Q. WHAT IS YOUR RECOMMENDED COST OF COMMON EQUITY FOR VALLEY?

A. Based upon my analysis, I recommend a cost of common equity of 10.51% for Valley (I&E Exhibit No. 2, Schedule 1).

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATION?

A. My recommendation is based on the use of the DCF method. As explained above, I used my CAPM result only to present a comparison to my DCF results. My DCF analysis uses the proxy group companies' spot dividend yield, a 52-week dividend yield, and five-year earnings growth forecasts. In calculating the dividend yield, I use the forecasted dividend. My DCF result provides a forward-looking estimation for the cost of equity that would be more appropriate and consistent for FPFTY ratemaking.

DISCOUNTED CASH FLOW

Q. PLEASE EXPLAIN YOUR DCF ANALYSIS.

A. My analysis employs the constant growth DCF model as portrayed in the following formula:

$$K = D_1/P_0 + g$$

Where:

K = Cost of equity

D_1 = Dividend expected during the year

P_0 = Current price of the stock

g = Expected growth rate

When a forecast for D_1 is not available, D_0 (the current dividend) must be adjusted by one half of the expected growth rate to account for changes in the dividend paid in period one. As forecasts for each company in my proxy group are available from Value Line, no dividends are adjusted for the purpose of my analysis.

Q. PLEASE EXPLAIN HOW YOU DEVELOPED THE DIVIDEND YIELDS USED IN YOUR DCF ANALYSIS.

A. A representative dividend yield must be calculated over a time frame that avoids the problems of both short-term anomalies and stale data series. For my DCF analysis, the dividend yield calculation places equal emphasis on the most recent spot and the 52-week average dividend yields. The following table summarizes my dividend yield computations for the proxy group (I&E Exhibit No. 2, Schedule 4):

Proxy Group - Average Dividend Yields	
(a) Spot Dividend Yield	3.52%
(b) 52-week Average Dividend Yield	3.75%
(c) Average ((a +b) ÷ 2)	3.63%

Q. WHAT INFORMATION DID YOU RELY ON TO DETERMINE YOUR EXPECTED GROWTH RATE?

A. I have used five-year projected growth rate estimates from S&P, Value Line, and Zacks.

Q. WHAT ARE THE RESULTS OF YOUR FORECASTED EARNINGS GROWTH RATES?

A. The expected average growth rates for my gas proxy group range are 5.31% to 8.44% with an overall average growth rate of 6.87% (I&E Exhibit No. 2, Schedule 5).

Q. WHAT IS THE RESULT OF YOUR DCF ANALYSIS BASED ON YOUR RECOMMENDED DIVIDEND YIELD AND GROWTH RATE?

A. The results of my DCF analysis are calculated as follows (I&E Exhibit No. 2, Schedule 6):

K	$=$	D_1/P_0	$+$	g
10.51%	=	3.64%	+	6.87%

<u>CAPITAL ASSET PRICING MODEL</u>

Q. PLEASE EXPLAIN YOUR CAPM ANALYSIS.

A. My analysis employs the traditional CAPM as portrayed in the following formula:

$$K = R_f + \beta(R_m - R_f)$$

Where:

K	=	Cost of equity
R_f	=	Risk-free rate of return
R_m	=	Expected rate of return on the overall stock market
β	=	Beta measures the systematic risk of an asset

Q. WHAT IS BETA AS EMPLOYED IN YOUR CAPM ANALYSIS?

A. Beta is a measure of the systematic risk of a stock in relation to the rest of the stock market. A stock's beta is estimated by calculating the linear regression of a stock's return against the return on the overall stock market. The beta of a stock with a price pattern identical to that of the overall stock market will equal one. A stock with a price movement that is greater than the overall stock market will have a beta that is greater than one and would be described as having more investment risk than the market. Conversely, a stock with a price movement that is less than the overall stock market will have a beta of less than one and would be described as having less investment risk than the overall stock market.

Q. HOW DID YOU DETERMINE YOUR BETA FOR YOUR CAPM ANALYSIS?

A. In estimating an equity cost rate for my proxy group of seven companies, I used the average of the betas for the proxy group companies as provided in the Value

Line Investment Survey. The average beta for my proxy group is 0.80 (I&E Exhibit No. 2, Schedule 7).

Q. WHAT RISK-FREE RATE OF RETURN HAVE YOU USED FOR YOUR FORECASTED CAPM ANALYSIS?

A. I have chosen to use the risk-free rate of return (R_f) from the projected yield on 10-year Treasury Notes. The yield on the short-term T-Bill is a more theoretically correct parameter to represent a risk-free rate of return, however, it can be extremely volatile. The volatility of short-term T-Bills is directly influenced by Federal Reserve policy. On the other hand, the 30-year Treasury Bond exhibits more stability but is not risk-free. Long-term Treasury Bonds have substantial maturity risk associated with market risk and the risk of unexpected inflation. Long-term treasuries normally offer higher yields to compensate investors for these risks. As a result, I chose to use the yield on the 10-year Treasury Note because it mitigates the shortcomings of the other two alternatives. Additionally, the Commission has historically agreed with I&E and recognized the 10-year Treasury Note as the superior measure of the risk-free rate of return.[13]

[13] *Pa. PUC v. UGI Utilities, Inc. - Electric Division;* Docket No. R-2017-2640058 (Order Entered October 25, 2018). *See generally* Disposition of Capital Asset Pricing Model (CAPM), p. 99; *Pa. PUC v. Aqua Pennsylvania, Inc.,* Docket Nos. R-2021-3027385 & R-2021-3027386, p. 154 (Order entered May 16, 2022); *Pa. PUC v. Valley Water Company*; Docket No. R-2023-3040258 (Order Entered January 18, 2024). See generally Disposition of Cost of Common Equity, pp. 107-108; Pa. PUC v. Pennsylvania-American Water Company; Docket Nos. R-2023-3043189 and R-2023-3043190 (Order Entered July 22, 2024). See generally Disposition of Capital Asset Pricing Model (CAPM), pp. 171-172.

The forecasted yield on the 10-year Treasury Note, as seen in Blue Chip Financial Forecasts,[14] is expected to range between 4.00% and 4.30% from the second quarter of 2025 through the second quarter of 2026, and it is forecasted to be 4.00% from 2026-2030. For my CAPM analysis, I used 4.13% risk-free rate, which is the average of all the yield forecasts I observed (I&E Exhibit No. 2, Schedule 8).

Q. HOW DID YOU DETERMINE THE ESTIMATED RETURN ON THE OVERALL STOCK MARKET EMPLOYED IN YOUR CAPM ANALYSIS?

A. To arrive at an estimated return on the overall stock market, I observed Value Line's 1700 stocks and the S&P 500 Index returns. The S&P 500 Index has an average return of 12.29% over the past 99 years (1926-2024) and the trendline for the returns over the past 99 years has been relatively flat (I&E Exhibit No. 2, Schedule 9). Value Line expects its universe of approximately 1700 stocks to have an average yearly return of 11.93% over the next three to five years based on a forecasted dividend yield of 2.20% and a yearly index appreciation of 45% (I&E Exhibit No. 2, Schedule 10). I have averaged S&P 500 return of 12.29% and Value Line return of 11.93%, producing an estimated market return of 12.11% (I&E Exhibit No. 2, Schedule 10).

[14] Blue Chip Financial Forecasts, Vol. 44, No. 5, May 1, 2025, p. 2.

Q. WHAT IS THE COST OF EQUITY RESULT FROM YOUR CAPM ANALYSIS?

A. The result of my analysis is as follows (I&E Exhibit No. 2, Schedule 11).

K	=	R_f	+	$\beta(R_m - R_f)$
10.51%	=	4.13%	+	0.80 (12.11% - 4.13%)

Q. HAVE YOU PROVIDED AN ADDITIONAL CAPM ANALYSIS?

A. Yes. I have provided an additional CAPM analysis using Kroll's (formerly Duff & Phelps) recommended U.S. Equity Risk Premium (ERP). Kroll is a trusted and publicly available source that bases its recommended ERP on current and forecasted economic and financial market conditions.

Q. WHAT IS KROLL'S CURRENT RECOMMENDED ERP?

A. Based on recent economic indicators and financial market conditions, Kroll recommends an ERP of 5.50% as of April 25, 2025.[15]

Q. WHAT IS THE COST OF EQUITY RESULT FROM YOUR CAPM ANALYSIS USING KROLL'S RECOMMENDED ERP?

A. The result of my analysis using Kroll's recommended ERP and 20-Year U.S.

[15] Kroll Cost of Capital Inputs Updated to Reflect Heightened Uncertainty in Global Economy (accessed on May 29, 2025).

Treasury yield as risk-free rate is as follows (I&E Exhibit No. 2, Schedule 11):

K	=	R_f	+	β(ERP)
9.36%	=	4.96%	+	0.80 (5.50%)

Q. WHAT IS THE RESULT OF YOUR CAPM ANALYSIS BASED ON THE AVERAGE OF CAPM WITH FORECASTED OVERALL MARKET RETURN AND CAPM WITH KROLL'S RECOMMENDED ERP?

A. The average of my CAPM analyses is 9.94% ((10.51% + 9.36%) ÷ 2) (I&E Exhibit No. 2, Schedule 11).

Q. DO YOU HAVE ANY ADDITIONAL COMMENTS REGARDING YOUR CAPM ANALYSIS?

A. Yes. As discussed above, my recommended cost of equity is based on my DCF analysis. I only present a CAPM analysis as a comparison and not for recommendation purposes as the inputs are highly subjective, and other than beta, the CAPM analysis result is not company or industry specific.

Q. IS IT NECESSARY TO APPLY THE CAPM WITH SIMILAR WEIGHT TO THE DCF WHEN DETERMINING A SPECIFIC RETURN ON EQUITY DUE TO RECENT INFLATIONARY TRENDS?

A. No. My use of the DCF as a primary method in determining an appropriate return

on equity already sufficiently takes inflationary trends into consideration. As mentioned above, the DCF includes a spot stock price in the dividend yield calculation and analysts who generate forecasted earnings growth would take inflation into consideration as well, so it contains the most up-to-date projected information of any model. In other words, the inputs of the DCF capture all known economic factors, including inflation.

CRITIQUE OF MR. D'ASCENDIS'S PROPOSED COST OF EQUITY

Q. DO YOU AGREE WITH MR. D'ASCENDIS'S PROPOSED COST OF EQUITY?

A. No. I disagree with Mr. D'Ascendis's proposed cost of equity for several reasons. First, I disagree with the weights given to the results of CAPM including the Empirical CAPM (ECAPM), and RP analyses of the Gas Utility Proxy Group in determining the cost of equity for Valley. Second, I take issue with certain aspects of Mr. D'Ascendis's risk analysis of Valley. Third, I disagree with his use of the 30-year Treasury Bond yield in place of the 10-year Treasury Note yield. Fourth, I disagree with Mr. D'Ascendis's application of a size adjustment/adder to the market analysis results. Fifth, I disagree with Mr. Mr. D'Ascendis's recommendation to include adder points to the market cost of equity for recognition of superior management performance.

Lastly, as discussed above, I disagree with Mr. D'Ascendis's consideration of the DCF, CAPM including ECAPM, and RP analysis results of Non-price

Regulated Companies Proxy Group used in determining the cost of equity for Valley.

WEIGHTS GIVEN TO THE CAPM/ECAPM AND RP METHODS

Q. DO YOU AGREE WITH MR. D'ASCENDIS'S RELIANCE ON THE CAPM/ECAPM AND RP MODELS?

A. No. I am not opposed to providing the Commission with the results of the traditional CAPM methodology for a point of comparison to the results of the DCF calculation; however, I am opposed to giving the CAPM including the ECAPM and RP model considerable weight in determining an appropriate cost of equity for Valley. For the reasons previously discussed in this testimony, it is inappropriate to give the CAPM including the ECAPM and RP model results similar weight to the DCF as Mr. D'Ascendis has done in creating his indicated cost of equity range of 11.34% to 12.97% after adjustments and recommending an 11.65% cost of equity rate for Valley (Valley Joint Statement No. 2, p. 5, line 5, Table 4 and p. 6, lines 3-8). As discussed above, the CAPM measures the cost of equity indirectly and can be manipulated by the time period chosen. Since the RP is a simplified version of the CAPM/ECAPM, it suffers these same flaws. I briefly discussed below the reasons for disagreement with the ECAPM's use alongside the traditional CAPM in a separate section below. Mr. D'Ascendis acknowledges that he is not aware of any instances where the Commission

explicitly relied on the RP analysis results in the last ten years (I&E Exhibit No. 2, Schedule 12).

RISK ANALYSIS

Q. PLEASE SUMMARIZE MR. D'ASCENDIS'S CLAIM REGARDING THE POTENTIAL BUSINESS RISK FACTORS THE COMPANY FACES.

A. Mr. D'Ascendis describes the Company's risk factors as unique to Valley. Mr. D'Ascendis states that business risks generally faced by utilities include, but are not limited to, the regulatory environment, mandatory environmental compliance requirements, customer mix and concentration of customers, service territory economic conditions, market demand, risks and uncertainties of supply, operations, capital intensity, size, the degree of operating leverage, emerging technologies including distributed energy resources, and the vagaries of weather (Valley Joint Statement No. 2, p. 10, lines 22-23 and p. 11, lines 1-4). Then, he claims that to the extent investors view a company as being exposed to higher risk, the required return will increase, and vice versa (Valley Joint Statement No. 2, p. 11, lines 9-11).

Q. WHAT IS YOUR RESPONSE TO MR. D'ASCENDIS'S CLAIM FOR VALLEY'S POTENTIAL BUSINESS RISKS?

A. Most companies in the natural gas utility sector face similar potential business risks of varying scale as mentioned above. Mr. D'Ascendis did not specifically

address any risks with quantitative and qualitative data faced by Valley, which are significantly dissimilar to the companies within his Gas Utility Proxy Group.

Q. WHAT IS MR. D'ASCENDIS'S CLAIM REGARDING POTENTIAL FINANCIAL RISK FACTORS THE COMPANY FACES?

A. First, Mr. D'Ascendis states that financial risk is the additional risk created by the introduction of debt and preferred stock into the capital structure. The higher the proportion of debt and preferred stock in the capital structure, the higher the financial risk to common equity owners and the equity investors demand higher returns as compensation for bearing higher financial risk (Valley Joint Statement No. 2, p. 12, lines 13-18). Second, Mr. D'Ascendis states that similar bond ratings/issuer credit ratings reflect and are representative of similar combined business and financial risks (i.e., investment risk) faced by bond investors. Although specific business or financial risks may differ between companies, the same bond/credit rating indicates that the combined risks are roughly similar from a debtholder perspective. He agrees that the debtholder risk measures do not translate directly to risks for common equity (Valley Joint Statement No. 2, p. 12, lines 22-23 and p. 13, lines 1-4).

Q. WHAT ARE YOUR COMMENTS REGARDING MR. D'ASCENDIS'S FINANCIAL RISK DISCUSSION?

A. Mr. D'Ascendis discussed, in general, higher financial risk for higher debt and

preferred stock in the capital structure faced by all companies and did not specifically address financial risks with quantitative and qualitative data faced by Valley, which are significantly dissimilar to the companies within his Gas Utility Proxy Group.

Q. WHAT IS YOUR RESPONSE TO MR. D'ASCENDIS'S OVERALL INVESTMENT RISK ASSESSMENT?

A. The risks referenced by Mr. D'Ascendis affect the entire gas utility industry, therefore, Valley faces the same exposure to these risks and uncertainties as all the other companies in our proxy groups. Investors voluntarily buy and hold stocks in natural gas utility companies, indicating they are aware of these risks and the returns. The cost of equity I recommend in this proceeding is adequately measured by my proxy group. Therefore, any additional consideration of the Company's risk profile and making corresponding adjustments or adders in determining the cost of equity for Valley is unwarranted, unjustified, and unsupported.

COST OF EQUITY ADJUSTMENTS

RISK-FREE RATE OF RETURN

Q. HOW HAS MR. D'ASCENDIS CALCULATED THE PROSPECTIVE RISK-FREE RATE FOR USE IN THE CAPM MODEL?

A. Mr. D'Ascendis's calculation of the risk-free rate is similar to mine. He

considered the U.S. Treasury yield estimates published by Blue Chip Financial Forecasts for the six quarters (first quarter of 2025 through second quarter of 2026) and the long-term projections for the years 2026-2030 and 2031-2035 from the time of his analysis (Valley Joint Statement No. 2, p. 38, lines 10-13). However, he used the 30-year Treasury Bond while I employed the 10-year Treasury Note. Also, I used five quarters (second quarter of 2025 through second quarter of 2026) for the treasury rate and a long-range, five-year average, future data point accounting for 2026-2030 predictions. He recommends using a 4.55% risk-free rate for the CAPM analysis (Valley Joint Statement No. 2, p. 38, lines 9-10).

Q. WHAT COMMENTS DO YOU HAVE REGARDING MR. D'ASCENDIS'S RISK-FREE RATE?

A. I disagree with Mr. D'Ascendis's method and inputs to determine the risk-free rate based on the 30-year Treasury Bond yield. I must reiterate my earlier statements that long-term Treasury Bonds have substantial maturity risk associated with the market risk and the risk of unexpected inflation and normally offer higher yields to compensate investors for these risks. Using the 10-year Treasury Note is more appropriate to balance the short-term volatility risk and the long-term inflation risk.

The Commission has recognized the 10-year Treasury Note as the superior measure for the risk-free rate by stating the following,[16]

> We agree with I&E and the ALJs that using the yield on the 10-year Treasury Note provides a better measure of the risk-free rate of return than using the yield on the 30-year Treasury Bond, as recommended by UGI. In our view, using the 10-year Treasury Note balances the shortcomings of the short-term T-Bill and the 30-year Treasury Bond. Although long-term Treasury Bonds have less risk of being influenced by federal policies, they have substantial maturity risk associated with the market risk. In addition, long-term Treasury Bonds bear the risk of unexpected inflation.

Additionally, applying a long-term Treasury Bond yield projection for the years 2031-2035 is inappropriate and is too far out for determining the cost of capital for Valley's new rates to be effective in 2026.

CAPM MARKET RISK PREMIUM

Q. WHAT MARKET RISK PREMIUM DID MR. D'ASCENDIS USE IN HIS TRADITIONAL CAPM ANALYSIS FOR THE GAS UTILITY PROXY GROUP?

A. Mr. D'Ascendis used an 8.15% market risk premium in his CAPM analysis, calculated by averaging results of five measures for the historic and prospective market risk premium [(7.31% + 7.94% + 8.18% + 6.65% + 10.68%) ÷ 5] as shown in Table 10 (Valley Joint Statement No. 2, p. 40, lines 5-7).

[16] *Pa. PUC v. UGI Utilities, Inc. – Electric Division;* Docket No. R-2017-2640058 (Order entered October 25, 2018), p. 99. (Disposition of Capital Asset Pricing Model (CAPM)).

Q. DO YOU AGREE WITH MR. D'ASCENDIS'S USE OF AN AVERAGE MARKET RISK PREMIUM OF 8.15%?

A. No. Mr. D'Ascendis inappropriately mingled the historic risk premium with the prospective risk premium and used the average 8.15% risk premium in his CAPM analysis. Since the cost of equity is determined for the FPFTY, using a historic risk premium skews the prospective market risk premium and the CAPM results. In fact, Kroll's latest forecast (April 15, 2025) for the equity risk premium is 5.50%,[17] which is significantly lower than Mr. D'Ascendis's calculated risk premium of 8.15%.

Additionally, Mr. D'Ascendis inappropriately included the outlier 10.68% (15.23% - 4.55%) prospective equity risk premium using measures of capital appreciation and income returns for the S&P 500 in the calculation of average market risk premium (Valley Exhibit (DWD-1), Schedule DWD-5, p. 2). A market risk premium of 10.68% is 23.40% higher than the next lowest market risk premium of 8.18% included in his average risk premium calculation. Excluding the outlier market risk premium of 10.68%, the average market risk premium of his four measures is 7.52% [(7.31% + 7.94% + 8.18% + 6.65%) ÷ 4] as opposed to 8.15% applied in the CAPM analysis.

[17] Kroll Cost of Capital Inputs Updated to Reflect Heightened Uncertainty in Global Economy (accessed on June 17, 2025).

Q. WHAT WOULD BE MR. D'ASCENDIS'S TRADITIONAL CAPM RESULTS USING THE MODIFIED MARKET RISK PREMIUM?

A. Using the modified risk premium of 7.52%, Mr. D'Ascendis's traditional CAPM result would be 10.49% as opposed to 10.96% (Valley Exhibit (DWD-1), Schedule DWD-5, p. 1) as shown in the table below:

K	=	R	+	β (R_m - R_f)
10.49%	=	4.55%	+	0.79 (7.52%)

If he uses Kroll's risk premium of 5.50%, his CAPM result would be 8.90% as shown in the table below:

K	=	R	+	β (R_m - R_f)
8.90%	=	4.55%	+	0.79 (5.50%)

EMPIRICAL CAPM

Q. WHAT IS THE ECAPM?

A. The ECAPM is a modified version of the CAPM which attempts to address the belief that the actual risk versus return correlation is flatter than what is predicted by the CAPM. The implication is that the CAPM underestimates returns with lower levels of risk and over-estimates the returns associated with higher levels of risk. The ECAPM entails assigning 25% weight to the market beta (1.0) and 75%

weight to the individual company (or proxy group) beta.[18]

Q. EXPLAIN WHY YOU DISAGREE WITH MR. D'ASCENDIS'S USE OF THE ECAPM.

A. The use of the ECAPM in estimating the cost of capital does not increase the validity of the result, but instead it injects another measure of subjectivity into the CAPM in an attempt to make the Security Market Line more accurate. The ECAPM reduces the purpose of the beta, which is the only company-specific variable applied the CAPM model. This additional layer of subjectivity provides an even stronger basis to rely on the DCF, as I have done, as the primary method to calculate a utility's cost of equity.

Q. DO YOU AGREE WITH MR. D'ASCENDIS'S ECAPM RESULT FOR GAS UTILITY PROXY GROUP?

A. No. I recommend the Commission reject Mr. D'Ascendis's calculated ECAPM result, which he used along with the traditional CAPM result to produce a combined average CAPM result. Averaging the ECAPM with the traditional CAPM produce a result of 11.12% (average of mean and median results) as opposed to 10.96%, the average of mean and median results of traditional CAPM. Mr. D'Ascendis inflated the traditional CAPM result of 10.96% by simply combining the ECAPM to produce the indicated CAPM cost of equity rate of

[18] David C. Parcell, "The Cost of Capital – A Practitioner's Guide," 2020 Edition, p. 106.

11.12% (Valley Joint Statement No. 2, p. 40, lines 11-13 and Exhibit (DWD-1), Schedule DWD-5, p. 1).

SIZE PREMIUM ADJUSTMENT TO ANALYSIS RESULTS

Q. PLEASE EXPLAIN MR. D'ASCENDIS'S PROPOSED SIZE PREMIUM ADJUSTMENT TO THE ANALYSIS RESULTS.

A. Mr. D'Ascendis added a 100-basis point (1.00%) size premium adjustment to his indicated cost of common equity results range of 10.29% - 11.92% (Valley Joint Statement No. 2, p. 5, line 5, Table 4). He asserts that size affects business risk because smaller companies generally are less able to cope with significant events that affect sales, revenues, and earnings. For example, smaller companies face more risk exposure to business cycles and economic conditions, both nationally and locally. Additionally, the loss of revenues from a few larger customers would have a greater effect on a small company than on a bigger company with a large more diverse customer base (Valley Joint Statement No. 2, p. 47, lines 9-14). He claims that smaller firms are riskier and investors generally demand greater returns from smaller firms to compensate for less marketability and liquidity of their securities (Valley Joint Statement No. 2, p. 47, lines 15-17). Lastly, Mr. D'Ascendis cite financial literature of Kroll's Cost of Capital Navigator: U.S. Cost of Capital Module, Fama and French - "The Capital Asset Pricing Model: Theory and Evidence," and Eugene Brigham's notes (Valley Joint Statement No. 2, pp. 47-48) in support of his claim for a size adjustment for Valley.

Q. HOW DID MR. D'ASCENDIS CALCULATE A SIZE PREMIUM ADJUSTMENT OF 1.00%.

A. Mr. D'Ascendis measured size premium by comparing the market capitalization of Valley with Gas Utility Proxy Group's companies. The average companies in the Gas Utility Proxy Group have a market capitalization 253.8 times that of Valley's capitalization (Valley Joint Statement No. 2, p. 49, lines 14-15, Table 12). Using the Ibbotson Associates' size premia for the decile portfolios of the NYSE/AMEX/NASDAQ, the average size premium for the Gas Utility Proxy Group with market capitalizations of $4.721 billion falls in the 5th decile while Valley's estimated market capitalization of $18.603 million, placing it in the 10th decile, which results in a size premium spread of 3.73% between the 5th decile and 10th decile (Valley Joint Statement No. 2, p. 50, lines 10-19 and Valley Exhibit (DWD-1), Schedule DWD-8, p. 1). Relying on the standard deviation of 1.53% of the DCF model indicated results (10.29%), Mr. D'Ascendis recommends a 1.00% size premium adjustment or adder to the indicated cost of equity results (Valley Joint Statement No. 2, p. 51, lines 15-20).

Q. DO YOU AGREE WITH MR. D'ASCENDIS'S SIZE PREMIUM ADJUSTMENT TO THE INDICATED COST OF EQUITY RESULTS?

A. No. Mr. D'Ascendis's proposed size adjustment of 1.00% is unnecessary because the technical literature he cites supporting a size premium adjustment related to the small size of a company is not specific to the utility industry, and, therefore, has

no relevance in this proceeding. Regulated utilities stand out from non-regulated industries because all utilities, small or large, have a monopoly market environment that affords protection from competition risk. Valley is owned by C&T Enterprises, Inc., which provides Valley the required equity and loan funding support in addition to technical, operational, and managerial support. Moreover, it is improper to assume the market-to-book ratio of Valley is equal to the market-to-book ratio of the Gas Utility Proxy Group of seven companies to determine the size difference because Valley and C&T's stocks are not traded on the stock market. Therefore, it is inappropriate to determine that Valley's smaller size creates higher risk as compared to the Gas Utility Proxy Group companies thus qualifying Valley for a higher return.

Furthermore, any expense impact resulting from the lesser buying power of a smaller utility is reflected in the revenue requirement and the dollar-for-dollar recovery that applies to expenses. To apply an additional size adjustment to a smaller regulated utility would only duplicate the burden to ratepayers. Valley's cost of equity is determined based on market data of the Gas Utility Proxy Group and therefore there is no need to apply an unsupported size premium adder to inflate the market based cost of equity results. Lastly, In response to I&E-RR-21, Valley states that there have been no "large customers" accounts lost or gained in 2022, 2023, and 2024. One Compressed Natural Gas (CNG) station closed in April 2025 and another CNG station is expected to close later this year. However, the April 2025 station closure only affected a small portion of Valley's total

revenue, an average revenue loss of $2,389 and the later station closure would result in an average revenue loss of $1,773 (I&E Exhibit No. 2, Schedule 13).

Q. IS THERE ACADEMIC EVIDENCE THAT SUPPORTS YOUR CONCLUSION THAT A SIZE ADJUSTMENT IS NOT APPLICABLE TO UTILITY COMPANIES?

A. Yes. In the article "Utility Stocks and the Size Effect: An Empirical Analysis," Dr. Annie Wong concludes,

> The objective of this study is to examine if the size effect exists in the utility industry. After controlling for equity values, there is some weak evidence that firm size is a missing factor from the CAPM for the industrial but not for utility stocks. This implies that although the size phenomenon has been strongly documented for the industrials, the findings suggest that there is no need to adjust for the firm size in utility rate regulation.[19]

Valley presents no evidence to support the application of a non-utility study regarding a size adjustment to a utility setting. Absent any credible article to refute Dr. Wong's findings, Mr. D'Ascendis's proposed size adjustment of 1.00% should be rejected. The size premium data based on market capitalization is not reliable, because for certain periods, large-capitalization stocks outperform mid-capitalization stocks and vice versa, and it is difficult to establish a sufficient correlation to prove that size is a specific risk for utilities.

[19] Dr. Annie Wong, "Utility Stocks and the Size Effect: An Empirical Analysis," *Journal of Midwest Finance Association* 1993, pp. 95-101.

Q. CAN YOU PROVIDE ANY RELEVANT PRIOR COMISSION RULINGS ON THIS SUBEJCT?

A. The Commission has rejected the application of a size adjustment to the CAPM cost of equity calculation where it agreed that the literature the company cites is not specific to the utility industry.[20]

Mr. D'Ascendis cite the Commission order[21] in the 2019 Citizens' Electric base rate case where the Commission notes that it recognizes that Citizens' size is a factor in assessing its ability to attract capital (Valley Joint Statement No. 2, p. 51, lines 3-4). However, the Commission did not specifically approve or quantify a size premium adjustment/adder (in basis points or percentage) in Citizens' cost of equity. The Commission order[22] notes,

> Consistent with the foregoing discussion, like the ALJs, we shall not specify an exact size adjustment. Instead, we shall adopt the ALJs' recommendation that Citizens' be awarded a DCF cost of common equity of 9.49%. In our view, this cost of equity is reasonable and strikes an appropriate balance by recognizing the general inverse relationship between a company's size and its risk, while acknowledging that there is not substantial evidence in the record to prove that an explicit size basis point adjustment is warranted in this case.

Similarly, in the 2019 Valley's base rate case, the Commission order[23] notes,

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[20] *Pa. PUC v. UGI Utilities, Inc. – Electric Division;* Docket No. R-2017-2640058 (Order Entered October 25, 2018), p. 100 (Disposition of Cost of Common Equity).

[21] *Pa. PUC v. Citizens Electric Company of Lewisburg, PA*; Docket No. R-2019-3008212 (Order Entered April 27, 2020), p. 103 (Disposition of Cost of Common Equity).

[22] *Pa. PUC v. Citizens Electric Company of Lewisburg, PA*; Docket No. R-2019-3008212 (Order Entered April 27, 2020), p. 104 (Disposition of Cost of Common Equity).

[23] *Pa. PUC v. Valley Energy, Inc.*; Docket No. R-2019-3008209 (Order Entered April 27, 2020), p. 114 (Disposition of Cost of Common Equity).

> We decline to award an explicit 100-basis point size adjustment, as advocated by Valley. Consistent with the foregoing discussion, like the ALJs, we shall not specify an exact size adjustment. Instead, we shall adopt the ALJs' recommendation that the Company be awarded a DCF cost of common equity of 9.68%, which is one standard deviation above I&E's DCF recommendation of 8.46%. In our view, this cost of equity is reasonable and strikes an appropriate balance by recognizing the general inverse relationship between a company's size and its risk, while acknowledging that there is not substantial evidence in the record to prove that an explicit size basis point adjustment is warranted in this case.

Q. BASED ON THE COMPANY'S CLAIMED RATE BASE AND CAPITAL STRUCTURE, WHAT IS THE VALUE OF AN ADDITIONAL 100 BASIS POINTS FOR MR. D'ASCENDIS'S PROPOSED SIZE PREMIUM ADJUSTMENT TO THE COST OF EQUITY?

A. The example below illustrates the impact of 1.00% (100 basis points) to the Company's cost of equity if the size premium adjustment is allowed in the cost of equity when applied to the Company's total claimed rate base and capital structure:

Valley's Claimed Equity Percentage of Capital Structure*	49.94%
Size Premium Adjustment applied to the CAPM Results	1.00%
Claimed Rate Base*	$25,187,466
Impact Prior to Gross Up (0.4894 x 0.01 x $25,187,466)	$123,267
Gross Revenue Conversion Factor*	1.41943
Total Impact to Ratepayers ($123,267 x 1.41943)	**$174,969**

* Valley Exhibit (HSG-1), Schedule C1, p. 1.

In this example, an addition of 100 basis points for the size premium adjustment to the cost of equity would force ratepayers to fund an unwarranted additional amount of $174,969 annually to cover the increase of the overstated rate of return along with the associated impact resulting from increases to income taxes and uncollectibles.

MANAGEMENT PERFORMANCE

Q. DISCUSS THE COMPANY'S CLAIM SPECIFIC TO EXEMPLARY MANAGEMENT PERFORMANCE.

A. Mr. D'Ascendis proposes a 5-basis point (0.05%) upward adjustment to his recommended cost of equity range 10.29% - 11.92% in recognition of the Company's management performance (Valley Joint Statement No. 2, p. 52, lines 1-2 and Exhibit (DWD-1), Schedule DWD-1, p. 1). He primarily relies on the direct testimony of Company witness Edward E. Rogers (Valley Joint Statement No. 4) to support the consideration of additional basis points for Valley's management performance in the cost of equity (Valley Joint Statement No. 2, p. 51, lines 25-27).

Q. WHAT INFORMATION DOES MR. ROGERS PROVIDE TO SUPPORT THE COMPANY'S CLAIM FOR EFFECTIVE MANAGEMENT PERFORMANCE?

A. Mr. Rogers states that pursuant to 52 Pa. Code § 523, the Commission should

consider Valley's operations as supportive of the proposed performance adjustment for Valley's management performance demonstrated by its efforts, which include main replacements, low customer complaints, emergency response, favorable customer feedback, technology adoption (Smart hub use), the Pennsylvania Department of Community and Economic Development's grant use for the East Athens Expansion, and the low lost and unaccounted for gas volume (Valley Joint Statement No. 4, p. 9, lines 11-23, p. 10, lines 1-23, and p. 11, lines 1-3). He reasons that all these efforts provide material evidence of efficiency, effectiveness, and adequacy of services to customers.

Q. DO YOU AGREE WITH THE COMPANY'S CLAIMS REGARDING MANAGEMENT PERFORMANCE?

A. No. First, many of the topics presented by the Company fall within the categories of safe and reliable customer service and satisfaction required of every public utility under 66 Pa C.S.A. §1501. There is no basis or support for the addition of 5 basis points (0.05%) for superior or exemplary management performance. Additionally, all operating and management expenses and costs to implement various programs and initiatives listed above are recovered from ratepayers and the Company passes capital expenditure program costs to its ratepayers via base rates. Further, if the Company is effective at controlling operating and maintenance costs, those savings should flow through to ratepayers and/or investors. These savings would likely be offset by the addition of basis points for

management performance as ratepayers would have to fund the additional costs. This defeats the purpose of any cost cutting measures to benefit ratepayers. Lastly, Valley's efforts to continue providing safe, reliable, and efficient services does not demonstrate exemplary management performance that the Company has gone above and beyond what it is required to do under the Code and warrants recognition through an affirmative adjustment to its cost of common equity. The management effectiveness adjustment should only be awarded for management effectiveness in truly exceptional circumstances.

Q. ARE YOU AWARE OF ANY COMPANIES THAT HAVE RECENTLY RECEIVED ADDITIONAL BASIS POINTS IN RECOGNITION OF MANAGEMENT PERFORMANCE?

A. Yes. Most recently, the Commission awarded Aqua an addition of 25 basis points for its management performance efforts.[24] However, it is important to recognize that this addition was based specifically on Aqua rescuing troubled water and wastewater systems at the Commission's request. The Commission stated: [25]

> We specifically recognize Aqua's efforts and willingness to quickly provide emergency aid to various water and wastewater systems that needed substantial improvement. Aqua has often provided this emergency aid on short notice and at the request of the Commission or other parties to protect the public from egregious health and safety threats and to

[24] *Pa. PUC v. Aqua Pennsylvania, Inc.,* Docket Nos. R-2021-3027385 & R-2021-3027386, pp. 168-173 (Order entered May 16, 2022).

[25] *Pa. PUC v. Aqua Pennsylvania, Inc.,* Docket Nos. R-2021-3027385 & R-2021-3027386, p. 169 (Order entered May 16, 2022).

protect the Commonwealth's drinking water resources from catastrophic damage.

The Commission awarded a performance factor adjustment of 0.05% to Valley in a base rate case at Docket No. R-2019-3008209 and the Company asserts that the performance factor adjustment still applies in this case (Valley Joint Statement No. 2, p. 52, lines 5-9).

Q. DOES THE COMMISSION'S PAST ISSUANCE OF ADDITIONAL EQUITY POINTS TO RECOGNIZE MANAGEMENT PERFORMANCE MEAN THAT VALLEY SHOULD ALSO RECEIVE AN ADJUSTED RETURN ON EQUITY?

A. No. The issuance of equity points to recognize management performance should be done on a case-by-case basis. The situation in the Aqua proceeding as discussed above was very specific to Aqua rescuing troubled water and wastewater systems and preventing health and safety concerns regarding drinking water. This scenario does not apply to Valley. The Commission's reward for the management performance in the 2019 base rate case does not warrant or automatically qualify Valley for the performance reward in this base rate case as there is no record of evidence for change or exceptional performance since 2019.

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE CONSIDERATION OF ADDITIONAL BASIS POINTS FOR THE COMPANY'S MANAGEMENT PERFORMANCE?

A. I am aware that under 66 Pa C.S.A. § 523 the Commission has the authority to consider a utility's performance, however, it is not mandatory that the Commission grant additional basis points to the ROE. Ultimately, as alluded to above, true strong management performance is earning a higher return through efficient use of resources and cost cutting measures. The greater net income resulting from cost savings and true efficiency in management and operations is available to be passed on to both ratepayers and shareholders. I do not believe that Valley, or any utility should be gifted an additional 5 basis points for doing what they are required to do to provide adequate, efficient, safe, and reasonable service under 66 Pa C.S.A. §1501.

For all the reasons discussed above and the additional financial impact on ratepayers, I recommend that any addition of basis points to the cost of equity for management performance be disallowed.

Q. WHAT WOULD MR. D'ASCENDIS'S COST OF EQUITY RESULTS BE WITHOUT A SIZE PREMIUM ADJUSTMENT OF 1.00% AND MANAGEMENT PERFORMANCE REWARD OF 0.05%?

A. Mr. D'Ascendis's cost of equity results range would be 10.29% - 11.92% without the unnecessary size premium adjustment of 1.00% and management performance

adjustment of 0.05% in contrast to his indicated cost of equity range of 11.34% - 12.97% and the recommended cost of equity would be 10.60% rather than the claimed 11.65% cost of equity for Valley (Valley Joint Statement No. 2, p. 5, line 5, Table 4, p. 52, lines 19-20, and p. 53, lines 1-2).

OVERALL RATE OF RETURN RECOMMENDATION

Q. WHAT IS THE COMPANY'S PROPOSED COST OF EQUITY AND OVERALL RATE OF RETURN?

A. The Company recommends a cost of equity of 11.65% and an overall rate of return of 8.27%.

Q. WHAT IS I&E'S RECOMMENDED COST OF EQUITY AND OVERALL RATE OF RETURN?

A. I&E Exhibit No. 2, Schedule 1, shows the calculation of an appropriate cost of equity to be 10.51% with an overall rate of return for Valley to be 7.71%.

Q. DO YOU HAVE ANY FINAL COMMENTS REGARDING THE COMPANY'S PROPOSED RETURN ON EQUITY?

A. Yes. A report issued by Regulatory Research Associates, a group within S&P Global Market Intelligence,[26] illustrates that Valley's 11.65% requested return on

[26] S&P Global, RRA Regulatory Focus, "Major energy rate case decisions in US – January-March 2025, Quarterly update on decided rate cases," April 25, 2025.

equity is higher by 192 basis points (1.92%) than the average return on equity of 9.73% of all gas utility rate cases decided/approved by state regulatory authorities in the first quarter of 2025, largely in line with the 9.72% average return on equity for the full year 2024.

Finally, while I am aware of the rising costs of capital due to the after-effects of the pandemic and inflation, I believe it is equally important not to overburden ratepayers with consistent rate increases. Despite current economic conditions, Valley is requesting a record return on equity, which would burden customers' rates. As detailed above, the effect of Mr. D'Ascendis's adjustments to the market-determined cost of common equity are an enormous burden to ratepayers and are completely unwarranted and unnecessary.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes. However, any topics discussed, or assertions made by any Valley witnesses that I have not addressed should not be construed as I&E's agreement or acceptance of inputs, discussion, or assertions made by the Valley witnesses in this proceeding.

D. C. PATEL

PROFESSIONAL EXPERIENCE AND EDUCATION

EXPERIENCE:

- Pennsylvania Public Utility Commission, Harrisburg, Pennsylvania
  June 2015 to present
  Fixed Utility Financial Analyst, Bureau of Investigation and Enforcement
- Pennsylvania Insurance Department, Harrisburg, Pennsylvania
  March 2013 - June 2015
  Insurance Company Financial Analyst, Bureau of Company Licensing & Financial Analysis
- Pennsylvania Department of Revenue, Harrisburg, Pennsylvania
  November 2010 - March 2013
  Accounting Assistant, Bureau of Corporation Taxes (Accounting)
- Hersha Hospitality Management, Harrisburg, Pennsylvania
  June 2007 - November 2010
  Staff Accountant (Taxes), Accounting Department
- Corporate Experience-India
  February 1987 - April 2007
  Company Secretary for three different companies during this period, which were listed on the Stock Exchanges.

EDUCATION/CERTIFICATION:

- Gujarat State University, Ahmedabad, India:
  - Bachelor of Commerce (Major concentration: Accounting)
    June 1980 - April 1983
  - Bachelor of Law
    June 1983 - December 1988

- The Institute of Company Secretaries of India, New Delhi, India:
  Post Graduate Professional Degree: Company Secretary
  June 1983 - December 1985

RATE CASE TRAINING:

- Attended SURFA - 56th Financial Forum (ROR) in April 2025
- Attended SURFA - 54th Financial Forum (ROR) in April 2023
- Attended 37th Western NARUC Utility Rate School in May 2016

D. C. PATEL

PROFESSIONAL EXPERIENCE AND EDUCATION

WORKED ON THE FOLLOWING CASES (Testimony not required):

- R-2024-3049248 et al. City of Lock Haven - Water Department
- R-2024-3048767 - PECO Energy Co. - Gas Operations (1307(f))
- R-2024-3047014 - Valley Gas of Pennsylvania, Inc. (1307(f))
- R-2022-3032167 - Valley Gas of Pennsylvania, Inc. (Green Path Rider)
- R-2022-3031172 - Valley Gas of Pennsylvania, Inc. (1307(f))
- R-2021-3024349 - Valley Gas of Pennsylvania, Inc. (1307(f))
- R-2021-3023541 - National Fuel Gas Distribution Corporation (§ 1307(f))
- A-2020-3021460 - PA American Water Co.-Upper Pottsgrove-Wastewater (1329)
- A-2020-3020178 - PA American Water Co.-Valley Township-Wastewater (1329)
- A-2020-3019859 - PA American Water Co.-Valley Township-Water (1329)
- R-2020-3019661 - PECO Energy Co. - Gas Operations (1307(f))
- U-2020-3015258 - Pittsburgh Water and Sewer Authority
- R-2019-3008255 - Valley Gas of Pennsylvania, Inc. (1307(f))
- R-2018-3001568 - PECO Energy Co. - Gas Operations (1307(f))
- R-2018-3000253 - Valley Gas of Pennsylvania, Inc. (1307(f))
- R-2017-2631441 - Reynolds Water Co.
- A-2017-2629534 - PPL Electric Utilities (Restructuring Plan)
- R-2017-2602611 - PECO Energy Co. - Gas Operations (1307(f))
- R-2016-2567893 - Andreassi Gas Co.
- R-2016-2525128 - Valley Water Co. - Marietta Division
- R-2015-2493905 - Sands, Inc.
- R-2015-2479962 - Corner Water Supply and Service Corporation
- R-2015-2479955 - Allied Utility Services, Inc.

SUBMITTED TESTIMONY IN THE FOLLOWING CASES:

- R-2024-3052359 Pike County Light and Power Company - Electric
- P-2024-3050549 Deer Haven, LLC. (529)
- R-2024-3050208 The Newtown Artesian Water Company
- R-2024-3047068 First Energy Pennsylvania Electric Company
- R-2024-3046931 PECO Energy Co. - Electric Operations
- R-2024-3046519 Valley Gas of Pennsylvania, Inc.
- R-2024-3045192 et al. Veolia Water Pennsylvania, Inc.
- R-2023-3042804 et al. Community Utilities of Pennsylvania, Inc.
- R-2023-3043189 et al. PA American Water Co.
- R-2023-3038630 Valley Gas of Pennsylvania, Inc. (1307(f))
- R-2023-3037933 Philadelphia Gas Works

D. C. PATEL

PROFESSIONAL EXPERIENCE AND EDUCATION

- R-2022-3037368 UGI Electric, Inc. - Electric Division
- A-2022-3034143 Aqua Pennsylvania, Inc. - Borough of Shenandoah (Water System) (1329)
- R-2022-3031672 and R-2022-3031673 - PA American Water Co.
- R-2022-3031211 - Valley Gas of Pennsylvania, Inc.
- R-2021-3024773 et al. - Pittsburgh Water and Sewer Authority
- A-2021-3024058- PA American Water Co. - Borough of Brentwood (Wastewater System) - 1329
- A-2021-3024681 - PA American Water Co. - York City Sewer Authority/City of York (Wastewater System) (1329)
- R-2021-3024601 - PECO Energy Co. - Electric Operations
- A-2021-3024267 - Aqua Pennsylvania Wastewater, Inc. - Lower Makefield (WW) (1329)
- A-2020-3019634 - PA American Water Co. - Royersford Wastewater (1329)
- R-2020-3018993 - Valley Gas Pennsylvania, Inc. (1307(f))
- R-2020-3018929 - PECO Energy Co. - Gas Operations
- R-2020-3017951 et al. - Pittsburgh Water and Sewer Authority
- A-2019-3008491 - Aqua Pennsylvania Wastewater, Inc.
- R-2019-3008212 - Citizens Electric Company of Lewisburg, PA
- R-2019-3008208 - Wellsboro Electric Company
- R-2018-3006814 - UGI Utilities, Inc. (Gas Division)
- R-2018-3002645 and 3002647 - Pittsburgh Water and Sewer Authority
- R-2018-3000834 - Suez Water Pennsylvania, Inc.
- R-2018-2647577 - Valley Gas of Pennsylvania, Inc.
- M-2018-2640802 and M-2018-2640803 - Pittsburgh Water and Sewer Authority (Compliance Plan Stage 2)
- R-2017-2595853 - Pennsylvania American Water Co.
- R-2016-2580030 - UGI Penn Natural Gas, Inc.
- R-2016-2554150 - City of DuBois - Bureau of Water
- R-2016-2529660 - Valley Gas of Pennsylvania, Inc.
- P-2016-2526627 - PPL Electric Utilities Corp. (DSP IV)

I&E Exhibit No. 2
Witness: D. C. Patel

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

VALLEY ENERGY, INC.

Docket No. R-2025-3054393

Exhibit to Accompany

the

Direct Testimony

of

D. C. Patel

Bureau of Investigation & Enforcement

Concerning:

Rate of Return

I&E
Valley Energy, Inc.
Summary of Cost of Capital

Type of Capital	Ratio	Cost Rate	Weighted Cost
Long-Term Debt	51.06%	5.03%	2.57%
Common Equity	48.94%	10.51%	5.14%
Total	100.00%		7.71%

Proxy Group Capital Structure

	2024		2023		2022		2021		2020		Average
Atmos Energy Corp.											
Long-term Debt	$8,085.015	39.94%	$6,833.663	38.08%	$5,944.948	38.23%	$5,124.950	39.33%	$4,732.850	41.07%	39.33%
Short-Term Debt	-	0.00%	241.933	1.35%	184.967	1.19%	-	0.00%	-	0.00%	0.51%
Common Equity	12,157.669	60.06%	10,870.064	60.57%	9,419.091	60.58%	7,906.889	60.67%	6,791.203	58.93%	60.16%
	20,242.684	100.00%	17,945.660	100.00%	15,549.006	100.00%	13,031.839	100.00%	11,524.053	100.00%	100.00%
Chesapeake Utilities Corp.											
Long-term Debt	1,270.400	44.46%	1,197.625	45.65%	590.780	36.34%	558.474	35.93%	518.371	37.26%	39.93%
Short-Term Debt	196.500	6.88%	179.853	6.86%	202.157	12.43%	221.634	14.26%	175.644	12.63%	10.61%
Common Equity	1,390.200	48.66%	1,246.104	47.50%	832.801	51.23%	774.130	49.81%	697.085	50.11%	49.46%
	2,857.100	100.00%	2,623.582	100.00%	1,625.738	100.00%	1,554.238	100.00%	1,391.100	100.00%	100.00%
New Jersey Resources Corp.											
Long-term Debt	3,038.767	54.94%	2,916.040	56.52%	2,623.784	53.93%	2,303.527	53.43%	2,354.496	54.45%	54.65%
Short-Term Debt	291.800	5.28%	252.100	4.89%	423.950	8.71%	377.300	8.75%	125.350	2.90%	6.11%
Common Equity	2,200.443	39.78%	1,990.735	38.59%	1,817.210	37.35%	1,630.862	37.82%	1,844.692	42.66%	39.24%
	5,531.010	100.00%	5,158.875	100.00%	4,864.944	100.00%	4,311.689	100.00%	4,324.538	100.00%	100.00%
NiSource Inc.											
Long-term Debt	12,090.700	56.55%	11,081.300	50.57%	9,555.500	55.09%	9,211.300	60.71%	9,249.700	63.25%	57.23%
Short-Term Debt	604.600	2.83%	3,048.600	13.91%	1,761.900	10.16%	560.000	3.69%	503.000	3.44%	6.81%
Common Equity	8,684.200	40.62%	7,783.500	35.52%	6,028.900	34.76%	5,400.800	35.60%	4,872.200	33.31%	35.96%
	21,379.500	100.00%	21,913.400	100.00%	17,346.300	100.00%	15,172.100	100.00%	14,624.900	100.00%	100.00%
Northwest Natural Holding Co.											
Long-term Debt	1,755.269	53.02%	1,502.602	52.24%	1,325.132	48.03%	1,124.055	45.90%	940.702	44.08%	48.66%
Short-Term Debt	170.110	5.14%	89.780	3.12%	258.200	9.36%	389.500	15.91%	304.525	14.27%	9.56%
Common Equity	1,385.371	41.84%	1,283.838	44.64%	1,175.441	42.61%	935.146	38.19%	888.733	41.65%	41.78%
	3,310.750	100.00%	2,876.220	100.00%	2,758.773	100.00%	2,448.701	100.00%	2,133.960	100.00%	100.00%
ONE Gas Inc.											
Long-term Debt	2,396.686	37.36%	2,174.701	43.24%	2,679.143	46.07%	3,707.778	56.60%	1,613.228	37.83%	44.22%
Short-Term Debt	914.600	14.26%	88.500	1.76%	552.000	9.49%	494.000	7.54%	418.225	9.81%	8.57%
Common Equity	3,104.548	48.39%	2,765.877	55.00%	2,584.426	44.44%	2,349.532	35.86%	2,233.311	52.37%	47.21%
	6,415.834	100.00%	5,029.078	100.00%	5,815.569	100.00%	6,551.310	100.00%	4,264.764	100.00%	100.00%
Spire Inc.											
Long-term Debt	3,767.100	48.89%	3,624.200	49.96%	3,032.200	45.62%	2,992.800	49.22%	2,482.100	45.88%	47.91%
Short-Term Debt	947.000	12.29%	955.000	13.16%	1,037.500	15.61%	672.000	11.05%	648.000	11.98%	12.82%
Common Equity	2,990.700	38.82%	2,675.300	36.88%	2,576.500	38.77%	2,416.200	39.73%	2,280.300	42.15%	39.27%
	7,704.800	100.00%	7,254.500	100.00%	6,646.200	100.00%	6,081.000	100.00%	5,410.400	100.00%	100.00%

Five-Year Average Capital Structure						
Long-term Debt	47.42%	**Maximum**	57.23%	**Minimum**	39.33%	
Short-Term Debt	7.85%	**Maximum**	12.82%	**Minimum**	0.51%	
Common Equity	44.73%	**Minimum**	35.96%	**Maximum**	60.16%	
	100.00%					

Source:
Compustat (S&P Global Market Intelligence - Data Management Solutions)
Yearly data updates typically provided late April of each year
($ in millions)

VALLEY ENERGY, INC.
DOCKET NO. R-2025-3054393

I&E-RR-8-D

Reference Valley Joint Statement No. 2, p. 20, lines 3-5 concerning the long-term debt cost claim of 5.03%. Provide the supporting calculation and documentation for the embedded interest rates associated with the fiscal year 2023, 2024, 2025, and 2026 showing a breakdown by each long-term debt issuance.

Response Provided By:
Melissa Sullivan, Chief Financial Officer, C&T Enterprises, Inc.

Date: May 28, 2025

Response:

Refer to I&E-RR-8-D Attachment A.

I&E-RR-8-D Attachment A

Debt Calculation
Valley Energy - PA

Acct	Name		Amount		
223.0	C&T Advance Acquistion		-		
224.0	Long Term Debt		6,333,387		
227.22	Capital Lease # 21A		-		
227.23	Capital Lease # 34		-		
227.24	Capital Lease #3		4,884		
227.25	Capital Lease #2		12,322		
227.26	Capital Lease #6		25,110		
227.27	Capital Lease #9		24,686		
227.28	Capital Lease #3		34,924		
243.22	Lease #21A		2,517		
243.23	Lease #34		2,762		
243.24	Lease #30		4,292		
243.25	Lease #22		7,315		
243.26	Lease #61		10,080		
243.27	Lease #92		5,586		
243.28	Lease #38		7,873		
	Unknown		-		
	Total Debt		6,475,737		
9003001	15 Year Fixed Rate	5.050%	1,211,122	15.6%	0.786%
9003002	FTM Fixed Rate	4.625%	1,219,567	15.7%	0.725%
9003003	15 Year Fixed Rate	5.050%	1,225,399	15.7%	0.795%
9003004	FTM Fixed Rate	2.885%	329,782	4.2%	0.122%
9003005	FTM Fixed Rate	4.275%	847,535	10.9%	0.465%
9021001/002	FTM Fixed Rate	3.220%	-	0.0%	0.000%
9021003	FTM Fixed Rate	2.410%	-	0.0%	0.000%
9024001	FTM Fixed Rate	6.270%	1,500,000	19.3%	1.208%
9026001	FTM Fixed Rate	5.050%	1,250,000	16.1%	0.811%
			7,583,404	97.4%	4.911%
	Lease #21A	4.780%	2,517	0.0%	0.002%
	Lease #34	4.780%	2,762	0.0%	0.002%
	Lease #30	4.721%	9,176	0.1%	0.006%
	Lease #22	4.790%	19,637	0.3%	0.012%
	Lease #61	6.240%	35,189	0.5%	0.028%
	Lease #92	5.820%	30,272	0.4%	0.023%
	Lease #38	5.970%	42,798	0.5%	0.033%
			201,959	2.6%	0.117%
			7,785,364	100.0%	**5.028%**

Proxy Group Long-Term Debt Cost

	2024		
	Interest Charges	**Long-Term Debt**	**Debt Cost**
Atmos Energy Corp.	$ 205.29	$ 8,085.01	2.54%
Chesapeake Utilities Corp.	69.80	1,270.40	5.49%
New Jersey Resources Corp.	135.00	3,038.77	4.44%
NiSource Inc.	557.30	12,092.70	4.61%
Northwest Natural Holding Co.	80.09	1,755.27	4.56%
ONE Gas Inc.	155.43	2,396.69	6.49%
Spire Inc.	218.10	3,767.10	5.79%
	Range:	**Low**	**2.54%**
		High	**6.49%**
		Average	**4.85%**

Source:
Compustat (S&P Global Market Intelligence - Data Management Solutions)
Yearly data updates typically provided late April of each year
(data in millions)

Mergent Bond Record A-Rated Public Utility Bond Yields	
Month	Yield
Jun-24	5.61%
Jul-24	5.64%
Aug-24	5.38%
Sep-24	5.20%
Oct-24	5.41%
Nov-24	5.55%
Dec-24	5.58%
Jan-25	5.87%
Feb-25	5.73%
Mar-25	5.72%
Apr-25	5.91%
May-25	5.91%
Average	**5.63%**

Source:
Mergent Bond Record
Jun-25

Dividend Yields of the Proxy Group

Company	Atmos Energy Corp.	Chesapeake Utilities Corp.	New Jersey Resources Corp.	NiSource Inc.	Northwest Natural Holding Co.	ONE Gas Inc.	Spire Inc.
Symbol	*ATO*	*CPK*	*NJR*	*NI*	*NWN*	*OGS*	SR
Div	3.68	2.82	1.95	1.20	1.97	2.72	3.26
52-wk low	110.97	102.64	41.58	27.60	34.82	58.31	57.77
52-wk high	167.45	136.73	51.95	41.45	44.38	82.25	79.81
Spot Price	156.49	123.00	46.20	39.28	41.41	75.21	75.40
Spot Div Yield	2.35%	2.29%	4.22%	3.05%	4.76%	3.62%	4.32%
52-wk Div Yield	2.64%	2.36%	4.17%	3.48%	4.97%	3.87%	4.74%
Average	**2.50%**	**2.32%**	**4.20%**	**3.27%**	**4.87%**	**3.74%**	**4.53%**

	Average
Spot Div Yield	**3.52%**
52-wk Div Yield	**3.75%**
Average	**3.63%**

Source: Barrons May 28, 2025
Value Line May 23, 2025

Five-Year Growth Estimate Forecast for Proxy Group

Company	Symbol	S&P	Zacks	Value Line	Average
		Source			
Atmos Energy Corp.	ATO	7.28%	7.20%	7.00%	7.16%
Chesapeake Utilities Corp.	CPK	8.88%	NA	8.00%	8.44%
New Jersey Resources Corp.	NJR	7.90%	NA	5.00%	6.45%
NiSource Inc.	NI	7.83%	7.90%	9.50%	8.41%
Northwest Natural Holding Co.	NWN	5.75%	NA	6.50%	6.13%
ONE Gas Inc.	OGS	5.84%	5.60%	4.50%	5.31%
Spire Inc.	SR	7.54%	6.50%	4.50%	6.18%
Average		**7.29%**	**6.80%**	**6.43%**	**6.87%**

Sources date:
(From Internet)
May 28, 2025 & May 23, 2025

Expected Market Cost Rate of Equity

Using Data for the Proxy Group of the Natural Gas Companies

5-Year Forecasted Growth Rates

	Time Period	Adjusted Dividend Yield	Growth Rate	Expected Return on Equity
		(1)	(2)	(3=1+2)
(1)	**52-Week Average Ending:** May 28, 2025	3.75%	6.87%	10.62%
(2)	**Spot Price Ending:** May 28, 2025	3.52%	6.87%	10.39%
(3)	**Average:**	**3.64%**	**6.87%**	**10.50%**
		3.64% +	**6.87%** =	**10.51%**

Sources: Value Line May 23, 2025
Barrons May 28, 2025

Proxy Group Beta

Company	Beta
Atmos Energy Corp.	0.75
Chesapeake Utilities Corp.	0.75
New Jersey Resources Corp.	0.85
NiSource Inc.	0.85
Northwest Natural Holding Co.	0.80
ONE Gas Inc.	0.80
Spire Inc.	0.80
Average beta for CAPM	**0.80**

Source:
Value Line
May 23, 2025

Risk-Free Rate Treasury note 10-yr Note	Yield
2Q 2025	4.30
3Q 2025	4.20
4Q 2025	4.10
1Q 2026	4.10
2Q 2026	4.10
2026-2030	4.00
Average	**4.13**

Source:
Blue Chip
May 1, 2025 & November 27, 2024

S&P 500 Historical Return (1926-2024)

Year	Return in %	Year	Return in %
2024	25.02	1971	14.31
2023	26.29	1970	4.01
2022	-18.11	1969	-8.5
2021	28.71	1968	11.06
2020	18.4	1967	23.98
2019	31.49	1966	-10.06
2018	-4.38	1965	12.45
2017	21.83	1964	16.48
2016	11.96	1963	22.8
2015	1.38	1962	-8.73
2014	13.69	1961	26.89
2013	32.39	1960	0.47
2012	16	1959	11.96
2011	2.11	1958	43.36
2010	15.06	1957	-10.78
2009	26.46	1956	6.56
2008	-37	1955	31.56
2007	5.49	1954	52.62
2006	15.79	1953	-0.99
2005	4.91	1952	18.37
2004	10.88	1951	24.02
2003	28.68	1950	31.71
2002	-22.1	1949	18.79
2001	-11.89	1948	5.5
2000	-9.1	1947	5.71
1999	21.04	1946	-8.07
1998	28.58	1945	36.44
1997	33.36	1944	19.75
1996	22.96	1943	25.9
1995	37.58	1942	20.34
1994	1.32	1941	-11.59
1993	10.08	1940	-9.78
1992	7.62	1939	-0.41
1991	30.47	1938	31.12
1990	-3.1	1937	-35.03
1989	31.69	1936	33.92
1988	16.61	1935	47.67
1987	5.25	1934	-1.44
1986	18.67	1933	53.99
1985	31.73	1932	-8.19
1984	6.27	1931	-43.34
1983	22.56	1930	-24.9
1982	21.55	1929	-8.42
1981	-4.91	1928	43.61
1980	32.42	1927	37.49
1979	18.44	1926	11.62
1978	6.56		
1977	-7.18	**Average**	**12.29**
1976	23.84		
1975	37.2		
1974	-26.47		
1973	-14.66		
1972	18.98		

Source:
https://www.slickcharts.com/sp500/returns#google_vignette
Accessed on May 29, 2025

Required Rate of Return on Market as a Whole Forecasted

	Dividend Yield	+	Growth Rate	=	Expected Market Return
Value Line Estimate	2.20%		9.73%	(a)	11.93%
S&P 500 Historical Return					12.29%
Average Expected Market Return				=	**12.11%**

(a) ((1+45%)^.25) -1) Value Line forecast for the 3 to 5 year index appreciation is 45%

Sources:

S&P 500 Historical Rate	1926-2024	12.29%
Value Line Dividend Yield	5/30/2025	2.20%
Value Line Appreciation Yield	5/30/2025	45.00%

CAPM with Forecasted Return

Re		Required return on individual equity security
Rf		Risk-free rate
Rm		Required return on the market as a whole
Be		Beta on individual equity security
Re	**=**	Rf+Be(Rm-Rf)
Rf	**=**	4.13
Rm	**=**	12.11
Be	**=**	0.80
Re	**=**	**10.51 (A)**

Sources:	Value Line	May 23, 2025
	Blue Chip	May 1, 2025 & November 27, 2024

CAPM Using Kroll ERP & 20-Year U.S. Treasury

Re		Required return on individual equity security
Rf		Risk-free rate
ERP		Equity Risk Premium
Be		Beta on individual equity security
Re	**=**	Rf+Be(ERP)
Rf	**=**	4.96
ERP	**=**	5.50
Be	**=**	0.80
Re	**=**	**9.36 (B)**

Sources:	Value Line	May 23, 2025
	Kroll	April 15, 2025
	CNBC	May 29, 2025

Average CAPM Results (A) and (B)	**9.94 (C)**

VALLEY ENERGY, INC.
DOCKET NO. R-2025-3054393

I&E-RR-12-D

Reference Valley Joint Statement No. 2, p. 38, line 1 (Table 9) concerning the RP analysis indicated result of 11.86%. State whether Mr. D'Ascendis is aware of any instances where the Commission specifically relied upon an RP analysis to determine an appropriate cost of equity in any Pennsylvania base rate proceeding in the last ten years. If so, identify the applicable cases, including the docket numbers.

Response Provided By:
Dylan W. D'Ascendis, Partner, ScottMadden Inc.
Ryan M. Kucan, Manager, ScottMadden Inc.

Date: May 28, 2025

Response:

Messrs. D'Ascendis and Kucan are not aware of any instances where the Commission relied upon an RP analysis in the last ten years specifically; however, in Docket No. R-2013-2360798, concerning Columbia Water Company, the Commission states in its disposition that:

> In this case, the range of ROE recommendations presented by the Parties based on the DCF methodology is 8.25% to 11.35%. Based on our review of the testimony, data, and cost models presented, we believe that the evidence in this case supports an ROE finding in the reasonable range of 9.25% to 10.25% using the DCF method as the foundation. The equity-heavy capital structure of Columbia indicates that a slightly lower ROE is appropriate. However, the small size of the Company, its management effectiveness, and the results of ROE models other than DCF are all reasons to set a higher ROE. Therefore, within our indicated range of reasonableness, we conclude that a ROE of 9.75% is appropriate for our ratemaking determinations herein.

While not specifically stated, the RPM was one of the models presented in that proceeding. Furthermore, in Docket No. R-2014-2402324, concerning Emporium Water Company, in the recommended decision, Administrative Law Judge Buckley states:

> The Company witness, Dylan W. D'Ascendis, recommended that the Commission authorize Emporium the opportunity to earn an overall rate of return of 7.17% based upon a comparable industry group hypothetical capital structure which consists of 46.29% long-term debt and 53.71% common equity at an embedded or actual debt cost rate of 2.68%. He also recommended a common equity cost rate of 11.05%. Emporium Statement No. 2 at 2. While the Commission may see fit to adjust this, these recommendations are at least in the zone of reasonableness and fiscal reality.

RESPONSE OF
VALLEY ENERGY INC.
TO THE BUREAU OF INVESTIGATION AND ENFORCEMENT
DATA REQUESTS
DOCKET NO. R-2025-3054393

I&E-RR-21

Reference Valley Statement No. 2, p. 51, lines 12-14, where Mr. Rea states that the loss of revenues from a few larger customers would have a greater effect on a small company. Identify all "large customer" accounts lost and gained by year for the years 2022, 2023, and 2024.

Response Provided By: Edward E. Rogers, President & CEO
Valley Energy, Inc.

Date: June 27, 2025

Response:

There have been no "large customers" accounts lost or gained for the years 2022, 2023, and 2024. With a smaller customer base, "large customers" losses have the potential to significantly affect revenues, e.g. one large industrial plant closure could result in an 8 percent decrease in revenues that would need to be absorbed by the remaining customers.

While there have been no large customers lost or gained in the last 3 years, the Company did lose a Transport Firm – DDQ customer, a Compressed Natural Gas (CNG) station that closed in April 2025 and was advised that another CNG station will close later this year. The station closure resulted in an average revenue loss of $2,389 and the latter station will result in an average revenue loss of$1,773, for a combined loss of $4,162. Both revenue losses were not addressed or included in the current filing.

I&E Statement No. 3
Witness: Esyan A. Sakaya

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

VALLEY ENERGY, INC.

Docket No. R-2025-3054393

Direct Testimony

of

Esyan A. Sakaya

Bureau of Investigation and Enforcement

Concerning:

Rate Base
Test Year
Reporting Requirements
Scale Back of Rates

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INTRODUCTION **1**

TEST YEAR **2**

UTILITY PLANT REPORTING REQUIREMENTS **3**

SCALE BACK OF RATES **7**

INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Esyan A. Sakaya. My business address is Pennsylvania Public Utility Commission, Commonwealth Keystone Building, 400 North Street, Harrisburg, Pennsylvania 17120.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed as a Fixed Utility Valuation Engineer in the Pennsylvania Public Utility Commission's (Commission) Bureau of Investigation and Enforcement (I&E).

Q. WHAT IS YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND?

A. My educational and professional background is set forth in the attached Appendix A.

Q. PLEASE DESCRIBE THE ROLE OF I&E IN RATE PROCEEDINGS.

A. I&E is responsible for protecting the public interest in proceedings before the Commission. The I&E analysis in this proceeding is based on its responsibility to represent the public interest. This responsibility requires balancing the interests of ratepayers, the regulated utility, and the regulated community as a whole.

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. My direct testimony relates to Valley Energy, Inc.'s (Valley or Company) request for a base rate revenue increase of $1,626,099 (Valley Ex. HSG-1, Sch. C1). My testimony specifically addresses the following issues:

- Test Year
- Rate Base
- Fully Projected Future Test Year Reporting Requirements
- Scale back of rates

Q. DOES YOUR DIRECT TESTIMONY INCLUDE AN EXHIBIT?

A. No.

TEST YEAR

Q. WHAT IS A TEST YEAR AND HOW IS IT USED BY A COMPANY IN A RATE PROCEEDING?

A. A test year is the twelve-month period over which a utility's costs and revenues are measured as the basis for setting prospective base rates. To meet its burden of proof, a utility has the option of using a historic test year (HTY), a future test year (FTY), or a Fully Projected Future Test Year (FPFTY). An HTY is a twelve-month period selected by a company that represents the most recent full year of actual data. An FTY begins the day after the HTY ends and is determined using a combination of actual data and a projection of annualized and normalized

estimates of future revenues and expenses and a corresponding rate base at the end of that period. The FPFTY is defined as the twelve-month period that begins with the first month that new rates will be placed into effect, after the application of the full suspension period permitted under Section 1308(d). The FPFTY created a shift from the fundamental ratemaking principle that a public utility should only be permitted to include projects in rate base and earn a reasonable return on its investments after they become "used and useful" for the utility's public service.

Q. WHAT TEST YEARS HAS THE COMPANY USED IN THIS PROCEEDING?

A. Valley has selected the year ended December 31, 2024 as the HTY, the year ending December 31, 2025 as the FTY, and the year ending December 31, 2026 as the FPFTY (Valley St. No. 1, p. 16).

Q. WHAT TEST YEAR HAS THE COMPANY BASED ITS REVENUE REQUIREMENT ON IN THIS PROCEEDING?

A. Valley based its requested revenue requirement on the FPFTY ending December 31, 2026 (Valley St. No. 1, p. 2).

UTILITY PLANT REPORTING REQUIREMENTS

Q. WHERE IS UTILITY PLANT IN SERVICE CLAIMED IN A RATE FILING?

A. Utility plant in service is claimed as a component of rate base.

Q. WHAT IS INCLUDED IN RATE BASE?

A. Rate base consists of the depreciated original cost of a utility's investment in plant a utility has in place to serve customers (utility plant in service) plus other additions and deductions that the Commission determines to be necessary to keep the utility operating and providing safe and reliable service to its customers.

Q. HOW IS RATE BASE USED WITHIN THE RATEMAKING FORMULA?

A. Rate base is one part of the financial equation used by the Commission to determine the appropriate revenue that a utility is granted in a rate proceeding. The revenue determination allows the utility to meet its expense obligations and gives it the opportunity to earn the rate of return established by the Commission in a rate proceeding. The equation used to determine the proper revenue requirement level is:

Revenue Requirement = (Rate Base x Rate of Return) + Operating Expenses + Depreciation Expenses + Taxes

Q. HOW IS THE DEPRECIATED ORIGINAL COST OF UTILITY PLANT IN SERVICE AT THE END OF THE TEST YEAR DETERMINED?

A. The depreciated original cost is equal to the original cost of the plant in service that is used and useful in the provision of utility service to the customers less the depreciation reserve as adjusted by other items such as salvage value and removal costs. By using an FPFTY, the depreciated original cost of the plant in service is

computed by taking a "snapshot" look at the value of used and useful utility plant estimated to be in service at the end of the FPFTY.

Q. WHAT IS THE COMPANY CLAIMING FOR UTILITY PLANT IN SERVICE FOR THE FPFTY ENDING DECEMBER 31, 2026?

A. The Company is claiming FPFTY assets of $49,963,792 less accumulated depreciation of $24,061,709 producing a net plant claim of $25,902,083 (Valley Ex. HSG-1, Sch. C1-5).

Q. HOW MUCH ADDITIONAL PLANT IN SERVICE DOES VALLEY CLAIM AS FTY AND FPFTY ADJUSTMENTS TO UTILITY PLANT?

A. The Company has projected $3,075,049 in FTY plant additions and $10,826 of FTY retirements, and $3,349,479 of FPFTY plant additions and $25,156 of FPFTY retirements, producing an FPFTY gross plant claim of $49,963,792 (Valley Ex. HSG-1, Sch. C3, p. 1, line 37).

Q. DO YOU HAVE ANY RECOMMENDED CHANGES TO UTILITY PLANT IN SERVICE OR CORRESPONDING DEPRECIATION?

A. No.

Q. DO YOU HAVE ANY RECOMMENDATIONS REGARDING PLANT ADDITIONS THAT THE COMPANY PROJECTS TO BE IN SERVICE DURING THE FTY ENDING DECEMBER 31, 2025, AND THE FPFTY ENDING DECEMBER 31, 2026?

A. Yes. I recommend that the Company be required to provide I&E and the Office of Consumer Advocate with an update to Valley Exhibit HSG-1, Schedule C3 no later than April 1, 2026, under this docket number, which should include actual plant additions and retirements by month for the year ending December 31, 2025. An additional update should be required for actual plant additions and retirements by month through December 31, 2026, no later than April 1, 2027.

Q. WHY DO YOU RECOMMEND THAT VALLEY BE REQUIRED TO PROVIDE THESE UPDATES?

A. There is value in determining how closely Valley's projected investments in future plant comport with the actual investments that are made by the end of the FTY and FPFTY. Determining the correlation between Valley's projected and actual results will help inform the Commission and the parties in future rate cases.

The updates are important because, as previously explained, by using an FPFTY, Valley is requiring ratepayers to pay a return on its projected investment in future plant that is not in place and providing service at the time the new rates take effect but also is not subject to any guarantee of being installed and placed into service. While the FPFTY provides for such projections, there should be verification of the projections. Therefore, requiring the Company to provide

updates demonstrating that actual investments comport with projections used in setting rates in the FPFTY provides the Commission with actual data to gauge the accuracy of Valley's projected investments in future proceedings and has become common practice among Pennsylvania utilities using an FPFTY.

SCALE BACK OF RATES

Q. PLEASE SUMMARIZE THE COMPANY'S PROPOSED INCREASE BY CLASS?

A. The Company proposes to increase Residential class revenue by $933,998 (29.56%), the Commercial class (Rate C) revenue by $270,382 (28.73%), the Interruptible class (Rate IS) revenue by $5,926 (29.28%), and the Small Industrial class (Rate SI) revenue by $4,184 (27.80%). For Transportation customers, the Company proposes the following increases: $107,445 (29.64%) for Firm customers, $90,410 (32.35%) for Firm-DDQ customers, $106,434 (29.56%) for Large Industrial customers (Rate I), and $107,333 (29.58%) for Transport. Interruptible customers. For contract customers, the Company is not proposing rate increases for the Firm-Fixed and Firm-Volumetric classes (Valley Ex. HSG-1, Sch. B4, p. 1).

Q. DOES THE COMPANY PROPOSE CORRESPONDING INCREASES TO THE CUSTOMER CHARGES?

A. Yes. The Company proposes from 13.36% to 18.68% for the Residential customer classes, from 13.90% to 14.88% for Commercial customers, depending on usage,

and from 10.57% to 21.95% for the Small Industrial customers (again depending on usage) (Valley Ex. HSG-1, Sch's. B5-1 and B5-2).

Q. WHAT IS A COST OF SERVICE STUDY (COSS)?

A. A COSS is an analysis of a Company's revenue, expenses, return, and taxes. In the analysis, these items are assigned or allocated to various rate classes such as Residential, Commercial, or Industrial to determine if the revenue received from each class is equal to, more than, or less than the corresponding cost of providing service to that class. It can include a customer cost analysis that determines the monthly fixed costs incurred to provide service to the various classes to establish the fixed customer charges.

Q. DID THE COMPANY PROVIDE A COST OF SERVICE STUDY?

A. No.

Q. WHAT SCALE BACK DO YOU RECOMMEND IF THE COMMISSION GRANTS LESS THAN THE FULL INCREASE?

A. If the Commission grants an increase less than the full amount requested, I recommend that the percentage increase for each class be adjusted so each class other than the Contract classes receive the same percentage increase.

Q. WHY DO YOU RECOMMEND THAT EACH CLASS OTHER THAN THE CONTRACT CLASSES RECEIVE THE SAME PERCENTAGE INCREASE?

A. The Company did not provide a COSS to compare the revenue received to the expenses incurred to provide service to each class. Thus, there is no justification for proposing a different percentage increase for the classes receiving an increase. Therefore, scaling back the rates so each class receives the same percentage increase is the most reasonable approach to establish rates if the Commission grants less than the full increase.

Q. DOES YOUR RECOMMENDATION TO SCALE BACK EACH CLASS SO THAT THE PERCENTAGE INCREASE FOR EACH CLASS IS THE SAME INCLUDE THE CUSTOMER CHARGES IN THOSE CLASSES?

A. Yes, I recommend that the scale back includes the customer charges for several reasons. First, the customer charges should be included in the scale back to limit the increase in the customer charge applicable to zero and low-usage customers. Second, this recommendation promotes conservation because it causes a larger portion of the customers' bill to be recovered in volumetric rates, thus giving customers more of an incentive to reduce usage. Finally, adjustments resulting in a reduced revenue requirement would also affect those items that are included in the customer costs, so any scale back related to a lower revenue allowance should also apply to customer charges.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

Esyan A. Sakaya

THE PENNSYLVANIA PUBLIC UTILITY COMMISSION
400 North Street
HARRISBURG, PA 17120

EXPERIENCE:

12/2018-Present
Pennsylvania Public Utility Commission-Harrisburg, PA
Fixed Utility Valuation Engineer - Assist in engineering related studies related to valuation, depreciation, cost of service, quality of service as they apply to regulated utilities. Contribute in evaluating, contrasting and conducting performance analyses in distinctive sections of valuation engineering and rate structure involving valuation concepts, original cost, rate base, fixed capital costs, inventory processing, excess capacity, cost of service, and rate design. Provide expert testimony in rate related utility cases.

4/2018-12/2018
Pennsylvania Department of Transportation-Harrisburg, PA
Photogrammetry Technician I - Created three-dimensional mapping layouts of natural and man-made features from stereoscopic images on a computer workstation. Assisted in the field placement of ground based surveyed control-points prior to aerial photography acquisition. Provided field support in the use of laser scans for comprehensive digital surveying data. Operated global positioning satellite surveying equipment to obtain accurate geodetic coordinates of pre-established benchmarks.

8/2017-4/2018
Pennoni and Associates. Consulting Engineers-King of Prussia, PA
Construction Inspector – Provided quality assurance in the onsite material testing of concrete, soils, and asphalt. Read and interpreted construction drawings and specifications of materials and components. Completed daily reports regarding project progress to engineers, project managers/superintendents, contractors, and clients.

EDUCATION:

National Association of Regulatory Utility Commissioners, Clearwater, FL
Utility Rate School; Utility Rate Making Basics, October 2019

Society of Depreciation Professionals, Philadelphia, PA
Introduction to Depreciation; Depreciation Fundamentals, September 2019

Temple University, Philadelphia, PA
Bachelor of Science; Major in Engineering Technology, 2015

Community College of Philadelphia, Philadelphia, PA
Associate of Applied Science; Major in Construction Management Technology, 2011

EDUCATION (CONTINUED):

Island School of Building Arts, Gabriola Island, BC-Canada
Certificate Graduate: Heavy Timber Construction August 2002-November 2002

Solar Energy International, Carbondale, CO
Certificate Graduate: Basic and Advanced Photovoltaic Design, April 2002-May 2002

TESTIMONY SUBMITTED:

I have assisted and/or submitted testimony in the following proceedings:

NO.	Case
1.	UGI Gas Utilities - Gas Division, Docket No. R-2018-3006814
2.	Newtown Artesian Water Company, Docket No. R-2018-3006904
3.	Pittsburgh Wastewater, Docket No. M-2018-2640803
4.	PAWC Purchase of Steelton, Docket No. A-2019-3006814
5.	Philadelphia Gas Works, Docket Nos. R-2019-3009016 & R-2019-3007636
6.	Community Utilities Water, Docket No. R-2019-3008947
7.	Aqua Purchase of Cheltenham, Docket No. A-2019-3008491
8.	UGI North, Docket No. R-2019-3009647
9.	UGI Central, Docket No. R-2019-3009647
10.	UGI South, Docket No. R-2019-3009647
11.	Twin Lakes Utilities, Docket No. R-2019-3010958
12.	Penn Power Company, Docket No. P-2019-3012628
13.	UGI Gas Utilities, Docket No. R-2019-3015162
14.	National Fuel and Gas Distribution, Docket No. R-2020-3015251
15.	Columbia Gas of PA, Docket Nos. R-2020-3018993 & R-2020-3018835
16.	Duquesne Light Company, Docket No. P-2020-3019522
17.	PA American Water Co., Docket Nos. R-2020-3019369 & R-2020-3010937
18.	Bethlehem Water Company, Docket No. R-2020-3020256
19.	Audubon Water Company, Docket No. R-2020-3020919
20.	Twin Lakes Utilities, Docket No. P-2020-3020914
21.	Pike County Light and Power-Gas, Docket No. R-2020-3022134
22.	Pike County Light and Power-Electric, Docket No. R-2020-3022135
23.	Duquesne Light Company, Docket No. R-2021-3024750
24.	Community Utilities Water, Docket No. R-2021-3025206

25. Community Utilities Wastewater, Docket No. R-2021-3025206
26. Hanover Municipal Water Works, Docket No. R-2021-3026116
27. Aqua Pennsylvania, Inc., Docket Nos. R-2021-3027385 & R-2021-3027386
28. Aqua Purchase of Willistown, Docket No. A-2021-3027268
29. National Fuel and Gas Distribution, Docket No. R-2022-3030235
30. UGI Gas Utilities, Docket No. R-2021-3030218
31. PECO Energy Company – Gas, Docket No. R-2022-3031113
32. Valley Energy, Inc., Gas, Docket No. R-2022-3032300
33. Citizens' Electric Company, Docket No. R-2022-3032369
34. Leatherstocking Gas Company, LLC Docket No. R-2022-303276
35. National Fuel and Gas Distribution, Docket No. R-2022-3035730
36. Aqua Purchase of Shenandoah, Docket No. A-2022-3034143
37. UGI Electric Utilities, Docket No. R-2022-3037368
38. Philadelphia Gas Works, Docket No. R-2023-3037933
39. Columbia Water, Docket No. R-2023-3040258
40. Community Utilities Water, Docket No. R-2023-3042804
41. Community Utilities Wastewater, Docket No. R-2023-3042805
42. CAN DO, Inc., Docket Nos. R-2023-3040153 and R-2023-3040151
43. Veolia Water, Inc., Docket No. R-2024-3045192
44. Veolia Wastewater, Inc., No. Docket R-2024-3045193
45. Columbia Gas Company, Docket No. R-2024-3046519
46. PECO Energy Company – Electric, Docket No. R-2024-3046931
47. City of Lock Haven - Water Department., Docket No. R-2024-3049248
48. Deer Haven Wastewater LLC, Docket No. P-2024-305049
49. Deer Haven Water LLC, Docket No. P-2024-305048
50. Pike County Light and Power – Electric, Docket No. R-2024-3052359
51. Columbia Gas Company, Docket No. R-2025-3053499
52. Philadelphia Gas Works, Docket No. R-2025-3053112

I&E Statement No. 1-SR
Witness: Christine Wilson

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

VALLEY ENERGY, INC.

Docket No. R-2025-3054393

Surrebuttal Testimony

of

Christine Wilson

Bureau of Investigation and Enforcement

Concerning:

OPERATING AND MAINTENANCE EXPENSES

INCOME TAX EXPENSE

RATE BASE

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INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Christine Wilson, and my business address is Pennsylvania Public Utility Commission, Commonwealth Keystone Building, 400 North Street, Harrisburg, PA 17120.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by the Pennsylvania Public Utility Commission (Commission) in the Bureau of Investigation and Enforcement (I&E) as a Fixed Utility Financial Analyst Supervisor.

Q. ARE YOU THE SAME CHRISTINE WILSON WHO PREPARED DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes. I have prepared I&E Statement No. 1 and I&E Exhibit No. 1.

Q. DOES YOUR SURREBUTTAL TESTIMONY INCLUDE AN ACCOMPANYING EXHIBIT?

A. No.

Q. WHAT IS THE PURPOSE OF YOUR SURREBUTTAL TESTIMONY?

A. The purpose of my surrebuttal testimony is to respond to the rebuttal testimony of the following witnesses for Valley Energy, Inc. (Valley or Company): Howard S.

Gorman, Valley Statement No. 1R; Edward E. Rogers, Valley Statement No. 4R; and Jamie Beale, Valley Statement No. 5R.

EFFECTIVE DATE OF NEW RATES

Q. WHAT TEST YEARS IS VALLEY USING IN THIS PROCEEDING?

A. Valley is using the year ended December 31, 2024, as the historic test year (HTY), the year ending December 31, 2025, as the future test year (FTY), and the year ending December 31, 2026, as the fully projected future test year (FPFTY) in this proceeding.[1] The Company indicates that its effective date of new rates is January 30, 2026, while also noting that a Commission-approved settlement between the parties could accelerate the effective date.

Q. SUMMARIZE YOUR DIRECT TESTIMONY REGARDING WHETHER NEW RATES SHOULD BE ALLOWED TO GO INTO EFFECT PRIOR TO THE JANUARY 30, 2026 EFFECTIVE DATE.

A. As stated in my direct testimony, rates should not go into effect prior to the beginning of the FPFTY which is January 1, 2026. This date is the beginning of the twelve-month period on which new rates are based. For this reason, it would be unjust and unreasonable for ratepayers to pay the increase in rates prior to the beginning of the first day of the FPFTY.

[1] Valley Statement No. 1, p. 2.

Q. DID ANY WITNESS RESPOND TO YOUR RECOMMENDATION?

A. No.

SUMMARY OF RECOMMENDED ADJUSTMENTS

Q. HAS VALLEY UPDATED ITS OVERALL REVENUE REQUIREMENT CLAIM IN REBUTTAL TESTIMONY?

A. Yes. The Company updated its requested overall increase to $1,285,942, a $340,157 ($1,626,099 - $1,285,942) reduction to the initial requested increase, based upon the updated FPFTY revenue requirement calculation.[2]

Q. PLEASE SUMMARIZE YOUR RECOMMENDED ADJUSTMENTS AS UPDATED IN THIS SURREBUTTAL TESTIMONY.

A. The following table summarizes my updated recommendations discussed herein:

	Company Claim	I&E Recommended Allowance	I&E Adjustment
Operating & Maintenance (O&M) Expense Adjustments			
Employee Pension & Benefits Exp.	$10,194	$6,502	($3,692)
Advertising Expense	$2,098	$0	($2,098)
Property Insurance Expense	$38,819	$35,856	($2,963)
Total O&M Adjustments			**($8,753)**

[2] Valley Statement No. 1R, p. 2 and Valley Exhibit HSG-1R, Schedule C1R.

Rate Base Adjustments:			
Unamortized Rate Case Expense	$230,556	$0	($230,556)
Cash Working Capital	$479,156	$478,062	($1,094)
Total Rate Base Adjustments			**($231,650)**

OVERALL I&E UPDATED POSITION

Q. WHAT IS I&E'S TOTAL UPDATED RECOMMENDED REVENUE REQUIREMENT?

A. I&E's total updated recommended revenue requirement is $7,565,294. This recommended revenue requirement represents an increase of $1,085,803 to present rate revenues of $6,506,491. This total recommended allowance incorporates my adjustments made in this surrebuttal testimony to O&M expenses and cash working capital, the Company's corrected state income tax rate of 7.49%,[3] and the recommended adjustments made in the testimony of I&E witness D.C. Patel.[4] I&E's updated recommended revenue requirement is shown below:

[3] Valley Statement No. 1R, p. 3.
[4] I&E Statement No. 2-SR.

Valley Energy, Inc.		TABLE I			
R-2025-3054393		INCOME SUMMARY			
	12/31/26	INVESTIGATION & ENFORCEMENT			
	Proforma	[----------			]
	Present Rates	Adjustments	Present Rates	Allowances	Proposed
	$	$	$	$	$
Operating Revenue	6,506,491	0	6,506,491	1,058,803	7,565,294
Deductions:					
O&M Expenses	3,979,819	-8,753	3,971,066	9,783	3,980,849
Depreciation	1,380,407	0	1,380,407		1,380,407
Taxes, Other	33,587	0	33,587	0	33,587
Income Taxes:					
Current State	-28,885	1,102	-27,783	78,572	50,789
Current Federal	-22,618	2,857	-19,761	203,794	184,033
Deferred Taxes	0	0	0		0
ITC	0	0	0		0
Total Deductions	5,342,310	-4,794	5,337,516	292,149	5,629,665
Income Available	1,164,181	4,794	1,168,975	766,654	1,935,629
Rate Base	25,337,084	-231,650	25,105,434	0	25,105,434
Rate of Return	4.59%		4.66%		7.71%

RATE CASE EXPENSE

Q. SUMMARIZE YOUR RECOMMENDATION IN DIRECT TESTIMONY FOR RATE CASE EXPENSE.

A. In contrast to the Company's claim for a 36-month amortization of rate case expense, I recommended that this expense be normalized over 60 months. While the Company stated that it needs to file rate cases every three years to avoid a large rate increase at one time, Valley's historic filing frequency precisely computes to a 60-month average filing frequency. For the reasons explained in my direct testimony, normalization is the appropriate treatment for this expense to allow for the transformation of this operating expense into a normal test year allowance. My recommendation produced an allowance of $55,333 [($276,667 ÷

60 months) x 12 months], or a reduction of $36,889 ($92,222 - $55,333) to the Company's claim.[5]

Furthermore, as described in my direct testimony, there are numerous recent cases where the Commission agreed that a historic filing frequency produces a more accurate allowance.[6]

Q. DID ANY WITNESSES RESPOND TO YOUR RECOMMENDATION?

A. Yes. Valley witness Howard Gorman disagrees with my recommendation. Additionally, OCA witness Greg Meyer responds to my recommendation as explained below.

Q. PLEASE SUMMARIZE MR. GORMAN'S RESPONSE.

A. Mr. Gorman explains how the long gap between the 2010 and 2019 rate filings was due to the Moxie project that provided incremental revenue to the Company, that this was addressed in the 2019 Valley rate filing at Docket No. R-2019-3008209, and as a result, the Commission granted a 36-month normalization period for rate case expense in that proceeding.

[5] I&E Statement No. 1, pp. 6-10.
[6] I&E Statement No. 1, pp. 10-12.

Q. DO YOU ACCEPT MR. GORMAN'S EXPLANATION ABOUT THE MOXIE PROJECT ALLOWING THE COMPANY TO ABSTAIN FROM FILING A RATE CASE BETWEEN 2010 AND 2019?

A. Yes. I have verified that in the 2019 Valley rate proceeding the Commission granted a 36-month normalization period due to the addition of this large contract customer which allowed for a longer time between rate filings.[7]

Q. DID ANY WITNESSES RESPOND TO YOUR ARGUMENT THAT RATE CASE EXPENSE SHOULD BE NORMALIZED AND NOT AMORTIZED FOR RATEMAKING?

A. Yes. OCA witness Greg Meyer agrees with my recommendation that rate case expense should be normalized as opposed to amortized but accepts the Company's filing frequency of 36 months based on Valley's most recent two rate case filings.[8] However, Valley witness Gorman disagrees and continues to recommend that rate case expense be amortized for ratemaking purposes. His argument concerning amortization versus normalization will be addressed in the "Unamortized Rate Case Expense in Rate Base" section that follows.

[7] *PA PUC v. Valley Energy, Inc.*, Docket No. R-2019-3008209, Opinion and Order, pp. 50-54 (Order Entered April 27, 2020).

[8] OCA Statement No. 1R, p. 6.

Q. DO YOU HAVE ANY CHANGES TO YOUR RECOMMENDATION FOR RATE CASE EXPENSE?

A. Yes. I continue to recommend normalization of rate case expense for the reasons summarized above and in my direct testimony. Since I accept the 36-month normalization period based on the Commission's 2019 order as those circumstances still apply, I am withdrawing my recommended dollar adjustment to rate case expense. However, I continue to recommend disallowance of the related rate base claim as explained below.

UNAMORTIZED RATE CASE EXPENSE IN RATE BASE

Q. SUMMARIZE YOUR RECOMMENDATION IN DIRECT TESTIMONY FOR UNAMORTIZED RATE CASE EXPENSE.

A. In direct testimony, I recommended the complete disallowance of unamortized rate case expense of $230,556 that was included in the Company's rate base claim.[9]

This recommendation was made because, as stated in my direct testimony, if the Company were allowed to include the unamortized rate case expense balance in rate base along with capturing an amount on the expense side, it would earn a return on, as well as a return of rate case expense. Any allowance for return on this routine operating expense, in addition to a return of such an expense, is not an appropriate ratemaking practice. Also, with respect to rate case expense,

[9] I&E Statement No. 1, p. 13.

normalization of such a claim, rather than amortization, is the appropriate ratemaking treatment, and normalization does not include a remaining balance nor allow for a remaining balance to be captured in rate base as it represents a prospective recovery of an ongoing expense between rate cases. Rate case expense represents a routine operating expense which is not extraordinary in nature. As such, rate base treatment of this cost should be disallowed.[10]

Q. DID ANY WITNESSES RESPOND TO YOUR RECOMMENDATION?

A. Yes. Mr. Gorman disagrees with my recommendation.[11] However, OCA witness Meyer agrees with my recommendation to disallow unamortized rate case expense in rate base.[12]

Q. PLEASE SUMMARIZE MR. GORMAN'S RESPONSE.

A. He disagrees with my assertion that rate case expense is a normal operating expense for a utility and that utilities should not earn a return on a normal operating expense. He asserts that Valley has working capital tied up in unrecovered rate case expense and opines that the Company should be allowed to earn a return on that amount. He further states that the Company pays the total on a real-time basis during the rate proceeding and collects a normalized amount over the normalization period without carrying charges. He disagrees with this

[10] I&E Statement No. 1, p. 14.
[11] Valley Statement No. 1R, pp. 4-5.
[12] OCA Statement No. 1R, pp. 6-7.

handling. Then he attempts to compare rate case expense to materials and supplies.[13]

Q. WHAT IS YOUR RESPONSE TO MR. GORMAN'S ARGUMENTS IN FAVOR OF AMORTIZATION TREATMENT OF RATE CASE EXPENSE?

A. What Mr. Gorman fails to acknowledge is that rate case expense is included in the computation for cash working capital. Rate case expense is an operating expense, unlike materials and supplies which are appropriately reflected in rate base for the capitalized amount.

As stated above and in my direct testimony, I reiterate that rate case expense is a routine operating expense for a regulated utility and as such should be normalized for ratemaking purposes.

Q. DO YOU HAVE ANY CHANGES TO YOUR RECOMMENDATION FOR UNAMORTIZED RATE CASE EXPENSE?

A. No. For all the reasons explained above and in my direct testimony, I continue to recommend that rate case expense be normalized and that the Company's claim for unamortized rate case expense of $230,556[14] in rate base be disallowed in its entirety.

[13] Valley Statement No. 1R, pp. 4-5.
[14] Valley Exhibit HSG-1R, Schedule C1-5R, p. 2.

REGULATORY COMMISSION EXPENSE

Q. SUMMARIZE YOUR RECOMMENDATION IN DIRECT TESTIMONY FOR REGULATORY COMMISSION EXPENSE.

A. In direct testimony I recommended an allowance of $47,317 or a reduction of $58,197 ($105,514 - $47,317) to the Company's claim. My recommendation was based on disallowing a duplicative amount for 2025 rate case expense of $58,197, since that expense was claimed elsewhere in the filing in Valley Exhibit HSG-1, Schedule C1, line 13 ($92,222).[15]

Q. DID ANY WITNESS RESPOND TO YOUR RECOMMENDATION?

A. Yes. Mr. Gorman accepts my recommendation; however, he misstates my adjustment by $2, stating that I recommend an adjustment of $58,195 and reducing regulatory commission expense by this amount.[16]

Q. DO YOU ACCEPT HIS CORRECTION TO REGULATORY COMMISSION EXPENSE?

A. Yes.

[15] I&E Statement No. 1, pp. 15-16.
[16] Valley Statement No. 1R, p. 5.

OFFICE SUPPLIES & EXPENSE

Q. SUMMARIZE YOUR RECOMMENDATION IN DIRECT TESTIMONY FOR OFFICE SUPPLIES & EXPENSE.

A. I recommended an allowance of $64,264 or a reduction of $17,126 ($81,390 - $64,264) to the Company's claim. My recommendation was based on averaging the most recent three years, 2022, 2023, and 2024 [($62,075 + $74,240 + $56,476) ÷ 3 = $64,264], due to the yearly fluctuation in this expense. This three-year average excludes the unsupported 3% inflation adjustment between the FTY and FPFTY and takes into consideration the yearly fluctuation in each line item reported in response to I&E-RE-10-D.[17]

Q. DID ANY WITNESS RESPOND TO YOUR RECOMMENDATION?

A. Yes. Valley witness Edward Rogers disagrees with my recommendation.

Q. PLEASE SUMMARIZE MR. ROGERS' RESPONSE.

A. Mr. Rogers disagrees with the historic three-year average and removal of the inflation adjustment for office supplies and expenses that I used in calculating my recommendation. He repeats arguments previously made concerning external pressures on cash flow in 2024, due to unexpected contractor expenses and material costs, and the need to cut back on travel and training expenses

[17] I&E Statement No. 1, p. 17 and I&E Exhibit No. 1, Schedule 5.

accordingly in that year. Finally, he argues that an annualized 2025 claim would be $84,890 based on its $42,445[18] year-to-date expense amount as of June 30, 2025, and that a 3% inflation amount is reasonable as compared to the percentage increases provided in response to I&E-RE-10-D.[19]

Q. DO YOU ACCEPT MR. ROGERS' ARGUMENT RELATED TO EXTERNAL PRESSURES ON CASH FLOW IN 2024 AND THAT THIS JUSTIFIES A LARGER FPFTY ALLOWANCE FOR OFFICE SUPPLIES & EXPENSE?

A. Yes. Based on further analysis of annual reports filed with the Commission by Valley since 2017, I have noticed that excluding the pandemic years 2020 and 2021, the average annual increase in office supplies and expense was approximately 16% per year. The yearly amounts for Account 921 shown in the annual reports is as follows:

2017 - $37,612

2018 - $52,025 (38% increase)

2019 - $56,085 (8% increase)

2020 - $30,312 (46% decrease likely due to pandemic)

2021 - $44,898 (48% increase likely due to pandemic)

2022 - $62,075 (38% increase)

[18] Valley Exhibit JB-2R.
[19] Valley Statement No. 4R, p. 9.

2023 - $74,240 (20% increase)

2024 - $56,476 (24% decrease)

Based on this historic data obtained via a document search on the Commission's website,[20] I have determined that the average annual increase from 2017 through 2024, excluding the pandemic years as noted above, is approximately 16% [(38% + 8% + 38% + 20% - 24%) ÷ 5]. Applying that 16% increase to the year 2023 ($74,240), produces an amount ($74,240 x 1.16 = $86,118) in line with but even above the Company's claim.

Q. DO YOU AGREE THAT IT WOULD BE PROPER TO ANNUALIZE THE YEAR-TO-DATE ACTUAL EXPENSE AS OF JUNE 30, 2025, AS A COMPARISON TO AN APPROPRIATE FPFTY CLAIM?

A. Not necessarily. There is no basis to assume that office supplies and expenses will be incurred equally in the first half and the second half of 2025, and I find this comparison not fully convincing. However, I do accept that annualizing the June 2025 year-to-date amount also produces an amount ($84,890) in line with the Company's claim.

[20] https://www.puc.pa.gov/search/document-search/?DocketNumber=&ReferenceDocketNumber=&eFilingConfirmationNumber=&CaseType=&PublicMeetingFromDate=&PublicMeetingToDate=&DocumentReceivedFromDate=&DocumentReceivedToDate=&DocumentServedFromDate=&DocumentServedToDate=&DocumentTitle=&DocumentType=11717119&UtilityCode=125100&UtilityName=&UtilityType=&ufprt=87A2FF0B4664F95EAC64EE1995AAC31AF56660600832141ED90E526149D3B6679EF27A9893BA5B320815DE26726FDAD181AD346D2294CF6572B7273DEAEC6275CEEB1E1B74310F4A4D9380C8EED52F3CF0539D1F0AE3DA1FB7C447390B5B440C3F9B2DDA908412732E5678FEFC0185FCCA91F640ED4CC5D0E53CFFA22097F10817C18B1A7FD6DA65323BE83BF4FAD207A7DFCD6AFB8DE6ABFFDE573C726CECD08E938B87BB08AFA5795D123888BB30E0AF9AD201242198A6BDF2CE2C16922D14#search-results, accessed August 14, 2025.

Q. DO YOU HAVE ANY CHANGES TO YOUR RECOMMENDATION?

A. Yes. Based on my analysis of the years 2017 through 2024 for this expense account, I have determined that the Company's claim appears to be in line with the general historical trend. However, I recommend that the Company be required to evaluate potential cost saving measures and report back in the next base rate filing what it has done to mitigate these excessive yearly increases.

It should be noted that I continue to disagree with 3% across the board inflation adjustments and did not use this methodology to determine acceptance of the Company's claim.

EMPLOYEE PENSION & BENEFITS EXPENSE

Q. SUMMARIZE YOUR RECOMMENDATION IN DIRECT TESTIMONY FOR EMPLOYEE PENSION & BENEFITS EXPENSE.

A. I recommended disallowance of the entire claim of $10,194 for employee pension and benefits expense. As stated in my direct testimony, I recommended disallowance of the entire amount because ratepayers should not be required to fund the Company's choice to offer or sponsor special events for its employees. I stated that, if leadership is inclined to hold such events, the Company should fund those picnics and celebrations, not the ratepayers. Additionally, I stated the salary survey that is built into the historic average due to a single 2024 survey is not appropriate since it is a historic one-time occurrence and should not be deferred for future recovery given the routine nature of the expense. This recommended

disallowance of the entire claim also addressed my concern about a blanket 3% inflation adjustment for this expense category that I disagree with in principle.[21]

Q. DID ANY WITNESS RESPOND TO YOUR RECOMMENDATION?

A. Yes. Valley witness Jamie Beale responded to my recommendation.

Q. PLEASE SUMMARIZE MS. BEALE'S RESPONSE.

A. Ms. Beale disagrees with my recommendation based on the Commission's prior support of this type of expense in the 2019 Citizens Electric Company of Lewisburg, PA (Citizens) rate case and counsel informing her that the Commission has "a long history" of allowing similar claims in rates. Furthermore, she indicates that senior management speaks at such events recognizing employee contributions and discussing safety and training.[22]

Q. DO YOU AGREE WITH MS. BEALE THAT THE TOTAL CLAIM SHOULD BE ALLOWED?

A. No. This expense has gone down every year between 2022 and 2024, and this makes a prior multi-year average adjusted for inflation[23] an inappropriate method to develop a proper claim amount.

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21 I&E Statement No. 1, pp. 18-19.
22 Valley Statement No. 5R, p. 3.
23 I&E Exhibit No. 1, Schedule 6, pp. 1-2.

Q. DO YOU HAVE ANY CHANGES TO YOUR RECOMMENDATION?

A. Yes. Based on the argument that the Commission allowed this similar claim in the 2019 Citizens rate case and that work-related matters were discussed at the events, I have a modification to my recommendation.

Q. WHAT IS YOUR UPDATED RECOMMENDATION?

A. I recommend an allowance of $6,502, or a reduction of $3,692 ($10,194 - $6,502) to the Company's claim.

Q. WHAT IS THE BASIS FOR YOUR UPDATED RECOMMENDATION?

A. This recommended allowance is appropriate since the actual amount of this expense has gone down every year from 2022 through 2024, and it is based on the 2024 actual expense incurred.[24]

ADVERTISING EXPENSE

Q. SUMMARIZE YOUR RECOMMENDATION IN DIRECT TESTIMONY FOR ADVERTISING EXPENSE.

A. I recommended disallowance of the entire $2,098 claim because ratepayers should not be required to fund the Company's choice to run such sponsorship ads shown in the response to I&E-RE-18-D.[25] As stated in my direct testimony, (1) if

[24] I&E Exhibit No. 1, Schedule 6, p. 2.
[25] I&E Exhibit No. 1, Schedule 7, pp. 2-11.

Company leadership is inclined to make such payments, they should be funded by the Company, not the ratepayers, since the ad examples provided indicate little to no tangible benefit to ratepayers;[26] (2) the ad examples appear redundant, as the same material shown in the ads can be shared on invoices, bill inserts, the Company's website and/or social media accounts; (3) ratepayers have no say in the choice of which charitable organizations should receive such sponsorships; and (4) my recommended disallowance of the entire claim also addresses my concern about a blanket 3% inflation adjustment for this expense category that I disagree with in principle.[27]

Q. DID ANY WITNESS RESPOND TO YOUR RECOMMENDATION?

A. Yes. Valley witness Jamie Beale disagrees with my recommendation.

[26] 66 Pa. C.S. § 1316(a) states:

> The [C]ommission shall also disallow as operating expense for ratemaking purposes expenditures for other advertising, unless and only to the extent that the [C]ommission finds that such advertising is reasonable and meets one or more of the following criteria:
>
> (1) Is required by law or regulation.
>
> (2) Is in support of the issuance, marketing, or acquisition of securities or other forms of financing.
>
> (3) Encourages energy independence by promoting the wise development and use of domestic sources of coal, oil, or natural gas and does not promote on method of generating electricity as preferable to other methods of generating electricity.
>
> (4) Provides important information to the public regarding safety, rate changes, means of reducing usage or bills, load management, or energy conservation.
>
> (5) Provides a direct benefit to ratepayers.
>
> (6) Is for the promotion of community service or economic development.

[27] I&E Statement No. 1, pp. 20-21.

Q. PLEASE SUMMARIZE MS. BEALE'S RESPONSE.

A. Ms. Beale asserts that my recommendation should be disallowed because the advertisements convey safety and other information to ratepayers.[28]

Q. DO YOU AGREE WITH MS. BEALE'S ASSERTION RELATED TO ADVERTISING EXPENSE?

A. No. I disagree that these ads placed via places like the rotary club, little league, softball teams, etc.[29] are necessary to convey safety and other customer communications when a limited set of ratepayers would participate in such organizations. These ads are duplicative to other more direct lines of communication coming from the Company via bill inserts, the Company's website, and its own social media pages. Thus, I continue to recommend that for the same reasons expressed in my direct testimony[30] and above that this $2,098 claim be disallowed.

Q. DO YOU HAVE ANY CHANGES TO YOUR RECOMMENDATION FOR ADVERTISING EXPENSE?

A. No.

[28] Valley Statement No. 5R, p. 4.
[29] I&E Exhibit No. 1, Schedule 7, p. 2.
[30] I&E Statement No. 1, pp. 20-21.

DUES/COMPANY MEMBERSHIPS

Q. SUMMARIZE YOUR RECOMMENDATION IN DIRECT TESTIMONY FOR DUES/COMPANY MEMBERSHIPS.

A. I recommended an allowance of $13,726 or a reduction of $3,569 ($17,295 - $13,726) to the Company's claim.[31] My recommendation was based on disallowance of amounts attributable to rotary club, chamber of commerce, and lobbying expense payments. Additionally, I stated that I disagreed with the unsupported 2% per year increases, however, not directly adjusting for such increases since my recommended adjustment was based on the Company's $15,070 supported amount and not the $17,295 claim.[32]

Q. DID ANY WITNESS RESPOND TO YOUR RECOMMENDATION?

A. Yes. Valley witness Jamie Beale responded to my recommendation.

Q. PLEASE SUMMARIZE MS. BEALE'S RESPONSE.

A. Ms. Beale agrees that dues and subscriptions for fraternal, social clubs, chamber of commerce organizations, and lobby expense should be excluded and has updated the Company's claim accordingly in rebuttal testimony to $15,951.[33]

[31] I&E Statement No. 1, p. 22.
[32] I&E Statement No. 1, p. 23.
[33] Valley Statement No. 5R, p. 4.

Q. DO YOU ACCEPT THE COMPANY'S CORRECTED CLAIM FOR DUES/COMPANY MEMBERSHIPS?

A. Yes. I accept the Company's correction to its claim based on the removal of subscriptions for fraternal, social clubs, chamber of commerce organizations, and lobbying expense. Additionally, I note that the Company identified a portion of the claim for the Energy Association of Pennsylvania[34] that was missing from the breakdown provided in response to I&E-RE-23-D.[35]

Q. DO YOU HAVE ANY CHANGES TO YOUR RECOMMENDATION?

A. Yes. Based on these corrections and clarification, I accept the Company's updated claim and withdraw my recommended adjustment.

PROPERTY INSURANCE EXPENSE

Q. SUMMARIZE YOUR RECOMMENDATION IN DIRECT TESTIMONY FOR PROPERTY INSURANCE EXPENSE.

A. I recommended an allowance of $35,856 or a reduction of $5,843 ($41,699 - $35,856) to the Company's claim. My recommendation was based on the known and measurable $2,988 monthly property insurance expense amount[36] annualized over twelve months, producing an FPFTY recommended allowance of $35,856 ($2,988 x 12). While property insurance had increased in prior years, the

[34] Valley Exhibit JB-1R.
[35] I&E Exhibit No. 1, Schedule 8.
[36] I&E Exhibit No. 1, Schedule 10, p. 4.

Company had just shopped and changed providers to reduce insurance costs, and thus, the historic average 12% increase is speculative. Instead, I recommended using the current known and measurable cost to produce an appropriate FPFTY allowance.[37]

Q. DID ANY WITNESS RESPOND TO YOUR RECOMMENDATION?

A. Yes. Valley witness Jamie Beale disagrees with my recommendation.

Q. PLEASE SUMMARIZE MS. BEALE'S RESPONSE.

A. Ms. Beale states that the Company has recently shopped for insurance, and based on this, Valley is comfortable accepting a reduction of $2,880 rather than my recommended reduction of $5,843.[38] This change produces an updated claim of $38,819 ($41,699 - $2,880).[39]

Q. DO YOU ACCEPT THE COMPANY'S UPDATED CLAIM FOR PROPERTY INSURANCE EXPENSE?

A. No. While I appreciate the movement toward what I believe is a more appropriate claim, the Company did not provide a clear explanation for the reduction of $2,880 to its claim as compared to my recommendation which was based on the most recent known cost.

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[37] I&E Statement No. 1, pp. 24-25.
[38] Valley Statement No. 5R, p. 4.
[39] Valley Exhibit HSG-1R, Schedule C1-1R, p. 2.

Q. DO YOU HAVE ANY CHANGES TO YOUR RECOMMENDATION?

A. Yes. Based on the Company's update to its claim, I must update my recommended adjustment.

Q. WHAT IS YOUR UPDATED RECOMMENDATION?

A. I continue to recommend an allowance of $35,856 based on the reasons summarized above and in my direct testimony, however, this recommended allowance now results in a reduction of $2,963 ($38,819 - $35,856) to the Company's updated claim.

INJURIES AND DAMAGES EXPENSE

Q. SUMMARIZE YOUR RECOMMENDATION IN DIRECT TESTIMONY FOR INJURIES AND DAMAGES EXPENSE.

A. I recommended an allowance of $108,946 or a reduction of $15,935 ($124,881 - $108,946) to the Company's claim which was meant to cover injuries and damages including automobile insurance.[40] My recommendation was based on the known and measurable $67,379 amount for injuries and damages and the $41,567 amount for automobile insurance. This recommendation was appropriate since the Company had just shopped to reduce its insurance cost after it was historically increasing from year to year.[41]

[40] I&E Statement No. 1, pp. 26-27.
[41] I&E Statement No. 1, pp. 27-28.

Q. DID ANY WITNESS RESPOND TO YOUR RECOMMENDATION?

A. Yes. Valley witness Jamie Beale responded to my recommendation.

Q. SUMMARIZE MS. BEALE'S RESPONSE.

A. Ms. Beale states that she finds my adjustment and a similar type of adjustment made by OCA witness Greg Meyer to be reasonable but for different reasons. She ultimately accepts the OCA adjustment of $30,981 to this account because the Company has shopped around to reduce the overall insurance cost and was therefore able to find comparable coverage at a lower premium.[42]

Q. DO YOU ACCEPT THE UPDATED CLAIM AMOUNT?

A. Yes. I find the larger reduction of $30,981 to the Company's claim reasonable and withdraw my original recommendation.

<u>CASH WORKING CAPITAL</u>

Q. SUMMARIZE YOUR RECOMMENDATION IN DIRECT TESTIMONY FOR CASH WORKING CAPITAL (CWC).

A. I recommended an allowance of $472,948 or reduction of $18,731 ($491,679 - $472,948) to the Company's claim based on all recommended adjustments to O&M expenses as discussed in my direct testimony.[43]

[42] Valley Statement No. 5R, pp. 2-3.
[43] I&E Statement No. 1, p. 29.

Q. DID ANY WITNESS RESPOND TO YOUR RECOMMENDATION?

A. Yes. Mr. Gorman addresses this issue by stating that I have accepted Valley's use of the one-eighth method, that the Company is using this method in its final revenue requirement calculation, and that he has updated the Company's claim based on the expense adjustments that affect the CWC calculation.[44]

Q. WHAT IS THE COMPANY'S UPDATED CLAIM FOR CWC?

A. The Company's updated CWC claim is $479,156.[45]

Q. DO YOU AGREE WITH THE COMPANY'S UPDATED CLAIM?

A. No. Due to our disagreement on a few remaining O&M issues, I also disagree with the Company's CWC claim. Thus, I am modifying my CWC recommendation to reflect the remaining O&M expense adjustments as discussed above.

Q. BASED ON THE ABOVE SURREBUTTAL TESTIMONY, WHAT IS YOUR UPDATED RECOMMENDED ALLOWANCE FOR CWC?

A. Reflecting all my recommended adjustments as discussed above, my updated recommendation for CWC is $478,062 or a reduction of $1,094 ($479,156 - $478,062) to the Company's claim.

[44] Valley Statement No. 1R, p. 5.
[45] Valley Exhibit HSG-1R, Schedule C1-5R, p. 1.

Q. HOW DID YOU CALCULATE YOUR UPDATED RECOMMENDATION?

A. The sum of all my recommended O&M adjustments shown in the "Summary of Recommended Adjustments" table above ($8,753) multiplied by 1/8th (or divided by 8) produces my recommended reduction of $1,094 ($8,753 ÷ 8) to CWC.

Q. IS YOUR RECOMMENDED CWC ALLOWANCE A FINAL RECOMMENDATION?

A. No. All adjustments to the Company's claims for revenues, expenses, taxes, and rate base must be continually brought together for each operating unit in the Administrative Law Judge's Recommended Decision and again in the Commission's Final Order. This process, known as iteration, effectively prevents the determination of a precise calculation until all adjustments have been made to the Company's claims.

Q. DOES THIS CONCLUDE YOUR SURREBUTTAL TESTIMONY?

A. Yes.

I&E Statement No. 2-SR
Witness: D. C. Patel

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

VALLEY ENERGY, INC.

Docket No. R-2025-3054393

Surrebuttal Testimony

of

D. C. Patel

Bureau of Investigation & Enforcement

Concerning:

Rate of Return

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INTRODUCTION OF WITNESS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is D. C. Patel and my business address is Pennsylvania Public Utility Commission, Commonwealth Keystone Building, 400 North Street, Harrisburg, PA 17120.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by the Pennsylvania Public Utility Commission (Commission) in the Bureau of Investigation & Enforcement (I&E) as a Fixed Utility Financial Analyst.

Q. ARE YOU THE SAME D. C. PATEL WHO SUBMITTED THE DIRECT TESTIMONY CONTAINED IN I&E STATEMENT NO. 2 AND I&E EXHIBIT NO. 2?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR SURREBUTTAL TESTIMONY?

A. The purpose of my surrebuttal testimony is to respond to the rebuttal testimony of by Valley Energy, Inc. (Valley or Company) witness Dylan W. D'Ascendis regarding rate of return topics including the cost of common equity and the overall

fair rate of return, which will be applied to the Company's rate base.[1] I will also address the Company's size adjustment and management performance claims discussed by Mr. D'Ascendis and Company witnesses Edward E. Rogers.[2] Additionally, I am addressing the rebuttal testimony of Pennsylvania Office of Consumer Advocate (OCA) witness Christopher C. Walters disputing my recommendation for Valley's return on equity (ROE), because it is based on the DCF results.[3]

The absence of any comments or responses to statements or topics addressed in Valley and the OCA's rebuttal testimony concerning the cost of common equity or ROE does not imply my acceptance or support of their positions in this proceeding.

Q. DOES YOUR SURREBUTTAL TESTIMONY INCLUDE AN EXHIBIT?

A. No. I refer to my direct testimony[4] and schedules contained in my exhibit[5] where necessary.

[1] Joint Statement No. 2R.
[2] Valley Statement No. 4R.
[3] OCA Statement No. 2-R.
[4] I&E Statement No. 2.
[5] I&E Exhibit No. 2.

Q. WHAT WAS YOUR ORIGINAL OVERALL RECOMMENDATION IN DIRECT TESTIMONY?

A. I recommended the following rate of return for the Company:[6]

I&E Recommendation Valley Energy, Inc. Summary of Cost of Capital			
Type of Capital	**Ratio**	**Cost Rate**	**Weighted Cost Rate**
Long-Term Debt	51.06%	5.03%	2.57%
Common Equity	48.94%	10.51%	5.14%
Total	**100.00%**		**7.71%**

SUMMARY OF MR. D'ASCENDIS'S REBUTTAL TESTIMONY

Q. SUMMARIZE MR. D'ASCENDIS'S RESPONSE TO YOUR RATE OF RETURN RECOMMENDATION.

A. Mr. D'Ascendis disputes my: (1) exclusive reliance on the Discounted Cash Flow (DCF) model for my ROE recommendation; (2) use and application of the Capital Asset Pricing Model (CAPM) and exclusion of the Empirical CAPM (ECAPM) analysis; (3) failure to reflect a size adjustment; and (4) my rejection of his use of the Risk Premium (RP) method.[7] Mr. D'Ascendis also takes issue with my dismissal of his Non-Price Regulated Proxy Group and his application of the cost

[6] I&E Statement No. 2, pp. 6-7 and I&E Exhibit No. 2, Schedule 1.
[7] Joint Statement No. 2R, pp. 7-12 and 14-26.

of equity analysis methods.[8] Finally, he disagrees with my recommended disallowance of additional basis points for management performance.[9]

MR. D'ASCENDIS'S UPDATED ANALYSIS

Q. DID THE COMPANY UPDATE ITS RATE OF RETURN CLAIM?

A. No. Mr. D'Ascendis provides updated cost of equity analysis results including his gas utility proxy group using market data as of July 18, 2025 because his original analysis was performed using market data as of February 28, 2025.[10] Based on the results produced by his updated analysis, his indicated common equity cost rate range (before adjustments) is 10.42% - 10.89%[11] in contrast to his originally indicated common equity cost rate range (before adjustments) of 10.29% - 11.92%.[12] Similarly, based on his updated analysis, his indicated common equity cost rate range (after adjustments) is 11.47% - 11.94%[13] in contrast to his originally indicated common equity cost rate range (after adjustments) of 10.34% - 12.97%.[14] However, Mr. D'Ascendis continues to support his original cost of equity recommendation of 11.65% and the overall rate of return of 8.27% as shown below:[15]

[8] Joint Statement No. 2R, pp. 27-30.
[9] Joint Statement No. 2R, p. 13.
[10] Joint Statement No. 2R, p. 4.
[11] Joint Statement No. 2R, p. 6 and Exhibit_(DWD-1R), Schedule DWD-1R, p. 2.
[12] Revised Joint Statement No. 2, p. 5, Table 4.
[13] Joint Statement No. 2R, p. 6 and Exhibit_(DWD-1R), Schedule DWD-1R, p. 2.
[14] Revised Joint Statement No. 2, p. 5, Table 4.
[15] Revised Joint Statement No. 2, p. 3, Table 1.

Valley Energy, Inc. Summary of Cost of Capital			
Type of Capital	**Ratio**	**Cost Rate**	**Weighted Cost Rate**
Long-Term Debt	51.06%	5.03%	2.57%
Common Equity	48.94%	11.65%	5.70%
Total	**100.00%**		**8.27%**

Q. DO YOU HAVE ANY UPDATES TO YOUR RATE OF RETURN ANALYSIS AND RECOMMENDATION?

A. No. My cost of equity analysis is based on the most recent market data at the time of my analysis; therefore, I have no changes.

DISCOUNTED CASH FLOW

Q. SUMMARIZE MR. D'ASCENDIS'S REBUTTAL TESTIMONY REGARDING YOUR DCF ANALYSIS.

A. Mr. D'Ascendis opines that I have inappropriately relied solely on the DCF model for my cost of equity recommendation. He states that using multiple models adds reliability to the estimation of the common equity cost rate and that using multiple cost of common equity models is supported in both the financial literature and regulatory precedent.[16] Relying on academic financial literature,[17] Mr. D'Ascendis asserts that using multiple models (the DCF, CAPM, and RP method)

[16] Joint Statement No. 2R, p. 14.
[17] Joint Statement No. 2R, pp. 14-16.

is appropriate in determining the cost of equity for Valley. He then cites Commission's orders[18] from 2013 for Columbia Water Company, 2014 for Emporium Water Company, and 2021 for Aqua Pennsylvania, Inc.'s base rate cases where the Commission relied on the DCF and CAPM results to determine the cost of equity for these utilities.

ALLEGED SOLE RELIANCE ON THE DCF

Q. PLEASE RESPOND TO MR. D'ASCENDIS'S ASSERTION THAT YOU RELIED SOLELY ON THE DCF.

A. As discussed at length in my direct testimony,[19] while my recommendation was based on the results of my DCF analysis, I also employed the CAPM as a comparison only, since the DCF method is the most reliable and accepted method for determining a forward-looking cost of equity estimation. The DCF model: (1) is based on the concept that the receipt of dividends plus expected appreciation is the total return requirement determined by the market; (2) uses the utilities' own stock prices and growth rates, which are directly employed in a formalistic calculation; (3) recognizes the time value of money and is forward-looking; and (4) has the most widespread regulatory acceptance.

I have considered the fact that no method can perfectly predict the ROE, which is why I also provided the CAPM as a comparison to the DCF. Although

[18] Joint Statement No. 2R, pp. 16-18.
[19] I&E Statement No. 2, pp. 21-24.

no one method can capture every factor that influences an investor, including the results of methods less reliable than the DCF, this does not make the end result of the DCF less reliable or less accurate. As a result, I stand by my method of using the DCF with a CAPM comparison, which is consistent with the methodology historically used by the Commission in base rate proceedings, even as recently as 2017, 2018, 2020, and 2021.[20]

Q. WHICH CASES DOES MR. D'ASCENDIS REFERENCE WHERE HE CLAIMS THE COMMISSION HAS CONSIDERED MULTIPLE COST OF EQUITY MODELS?

A. Mr. D'Ascendis references the 2013 Columbia Water Company,[21] the 2014 Emporium Water Company,[22] and the 2021 Aqua Pennsylvania, Inc.[23] cases to suggest the Commission has considered multiple cost of common equity models.

[20] *Pa. PUC v. City of DuBois – Bureau of Water*, Docket No. R-2016-2554150 (Order Entered March 28, 2017), *See generally* Disposition of Cost Rate Models, pp. 96-97. *Pa. PUC v. UGI Utilities, Inc. – Electric Division,* Docket No. R-2017-2640058 (Order Entered October 25, 2018), *See generally* Disposition of Cost of Common Equity, p. 119. *Pa. PUC v. Wellsboro Electric Company,* Docket No. R-2019-3008208 (Order Entered April 29, 2020), *See generally* Disposition of Primary Methodology to Determine ROE, pp. 80-81. *Pa. PUC v. Citizens Electric Company of Lewisburg, PA,* Docket No. R-2019-3008212 (Order Entered April 29, 2020). *See generally* Disposition of Cost of Common Equity, pp. 91-92. *Pa. PUC v. Columbia Gas of Pennsylvania, Inc.,* Docket No. R-2020-3018835 (Order Entered February 19, 2021), *See generally* Disposition of Cost of Common Equity, p. 131. *Pa. PUC v. PECO Energy Company – Gas Division*, Docket No. R-2020-3018929 (Order Entered June 22, 2021), *See generally* Disposition of Return of Rate on Common Equity, p. 171.

[21] *Pa. PUC v. The Columbia Water Company*, Docket No. R-2013-2360798 (Order Entered January 23, 2014).

[22] P*a. PUC v. Emporium Water Company*, Docket No. R-2014-2402324 (Order Entered January 28, 2015).

[23] *Pa. PUC v. Aqua Pennsylvania, Inc.,* Docket Nos. R-2021-3027385 and R-2021-3027386 (Order entered May 16, 2022).

Q. WHAT COMMENTS DO YOU HAVE REGARDING THE CASES MR. D'ASCENDIS REFERENCES?

A. First, within the citation Mr. D'Ascendis presents the Columbia Water Company case,[24] where the Commission states that,

> [T]he evidence in this case supports an ROE finding in the reasonable range of 9.25% to 10.25% using the *DCF method as the foundation* (emphasis added). Therefore, within our indicated range of reasonableness, we conclude that a ROE of 9.75% is appropriate for our ratemaking determinations herein.

The Commission order does not specifically mention its reliance on the results of other cost of equity methods in determining an appropriate ROE of 9.75%. Any adjustments to the cost of equity after the fact are at the Commission's discretion and independent of the result of any cost of equity model. In the Emporium Water case,[25] the Commission stated that "based on our review of the testimony, data, and cost models presented and considering our adoption of a 60% / 40% hypothetical capital structure, we believe that the range of returns provided in evidence supports an ROE finding of 10.0% for our ratemaking determinations herein."[26] The Commission simply summarized the recommendations presented by OCA, I&E, and the Company; it did not specifically comment on which model(s) it relied upon and any weighting assigned to each cost of equity models for determining a 10.0% ROE. Lastly, in the Aqua Pennsylvania case,[27] the

[24] Joint Statement No. 2R, pp. 16-17.
[25] Joint Statement No.2R p. 17.
[26] Joint Statement No, 2R, p. 17.
[27] Joint Statement No. 2R, pp.17-18.

Commission specifically noted that "we shall determine an appropriate ROE for Aqua using informed judgement based on I&E's DCF and CAPM methodologies."[28] As I stated in my direct testimony,[29] Aqua's return on equity of 10.00% is above the national average for water utility base rate cases, which demonstrates the problem associated with using the CAPM as a ceiling for determining a utility's return on equity.

CAPITAL ASSET PRICING MODEL

Q. SUMMARIZE MR. D'ASCENDIS'S RESPONSE TO YOUR CAPM ANALYSIS.

A. Mr. D'Ascendis disputes my use of the 10-year U.S. Treasury Note as a proxy to measure the risk-free rate that I use in my CAPM analysis.[30] He also disagrees with my exclusion of the ECAPM method in computing the Company's return on equity.[31]

RISK-FREE RATE

Q. WHAT IS MR. D'ASCENDIS'S RESPONSE TO YOUR USE OF THE YIELD ON THE 10-YEAR U.S. TREASURY NOTE?

A. Mr. D'Ascendis claims his use of the yield on a 30-year U.S. Treasury Bond is

[28] Joint Statement No. 2R, p. 18.
[29] I&E Statement No. 2, pp. 25-26.
[30] Joint Statement No. 2R, pp. 24-25.
[31] Joint Statement No. 2R, pp. 21-23.

more appropriate than my use of the yield on a 10-year Treasury Note because it better reflects the life of the underlying investment. He also claims 30-year U.S. Treasury Bonds do not have maturity risk as an investor will receive the stated coupon rate and principal when the bond has matured. Additionally, he asserts that since the cost of equity is a long-term concept, the investment horizon of an individual investor is irrelevant. He claims that equity securities represent a perpetual claim on cash flows, and 30-year Treasury bonds are the longest maturity securities available to match that perpetual claim. He then asserts that my use of a medium-term (10-year) Treasury Note does not match the life of the assets being valued.[32]

Q. IS THE LIFE OF THE INVESTMENT THE ONLY FACTOR THAT SHOULD BE CONSIDERED IN THE CHOICE OF A RISK-FREE RATE?

A. No. The risk-free rate is the return that can be earned without accepting any risk, and while the life of the investment can be considered in the choice of risk-free rates, the most important consideration is that the rate be as risk-free as possible. As explained in my direct testimony,[33] I chose the 10-year Treasury Note as it mitigates the shortcomings of the short-term Treasury Bill and the 30-year Treasury Bond. Although long-term Treasury Bonds have less risk of being influenced by federal policies, they have substantial maturity risk associated with

[32] Joint Statement No. 2R, pp. 24-25.
[33] I&E Statement No. 2, pp. 34-35.

market risk. In addition, long-term Treasury Bonds bear the risk of unexpected inflation. As such, my choice of a 10-year Treasury Note is appropriate. Further, as also pointed out in my direct testimony, the Commission recently agreed with I&E that the 10-year Treasury Note is the superior measure of the risk-free rate of return.[34] Finally, I disagree with Mr. D'Ascendis's statement that the cost of equity is a long-term concept and that the investment horizon of an individual investor is irrelevant. I believe an investor does not invest funds in perpetuity. Rather, an investor is interested in total return on investment over a certain period. If an investor finds another better investment opportunity or needs money for other purposes, they will switch or redeem their equity investment.

Q. DO YOU AGREE WITH MR. D'ASCENDIS THAT 30-YEAR TREASURY BONDS DO NOT HAVE MATURITY RISK?

A. No. Longer term bonds have maturity risk associated with them because long-term forecasts are less accurate in predicting inflation, interest rates, the market as a whole, changes in the tax code, and other unpredictable events that affect the value of a bond; therefore, their uncertainty, or risk, is increased. As a result, the 10-year U.S. Treasury Note is superior to the 30-year Treasury Bond in providing a measurement of the risk-free rate of return.

[34] *Pa. PUC v. UGI Utilities, Inc. - Electric Division,* Docket No. R-2017-2640058 (Order Entered October 25, 2018). *See generally* Disposition of Capital Asset Pricing Model (CAPM), p. 99.

MARKET RISK PREMIUM (MRP)

Q. SUMMARIZE MR. D'ASCENDIS'S RESPONSE TO YOUR DISAGREEMENT WITH HIS USE OF AN AVERAGE MARKET RISK PREMIUM OF 8.15% IN THE CAPM ANALYSIS.

A. Mr. D'Ascendis claims that his calculated market returns and MRPs are consistent with the actual realized returns and MRPs. Therefore, he dismisses my concern about his use of an 8.15% average of the historic risk premium and prospective risk premium used in his CAPM analysis.[35]

Q. WHAT IS YOUR RESPONSE TO MR. D'ASCENDIS REJECTING YOUR DISAGREEMENT WITH THE MRP USED IN HIS CAPM ANALYSIS?

A. In rebuttal testimony, Mr. D'Ascendis presents a revised MRP of 8.86%[36] in place of the 8.15% MRP used in his original CAPM analysis. As discussed in my direct testimony,[37] using a historic market risk premium skews the prospective market risk premium and the CAPM results. Kroll's latest forecast (as of April 15, 2025) for the MRP (equity risk premium) is 5.50%, which is significantly lower than Mr. D'Ascendis's calculated average MRP of 8.15% and the updated MRP of 8.86%.

[35] Joint Statement No. 2R, pp. 25-27.
[36] Joint Statement No. 2R, p. 25.
[37] I&E Statement No. 2, pp. 45-46.

EXCLUSION OF THE ECAPM

Q. PLEASE SUMMARIZE MR. D'ASCENDIS'S RESPONSE TO YOUR EXCLUSION OF THE ECAPM IN YOUR ANALYSIS.

A. Mr. D'Ascendis asserts that the empirical Security Market Line (SML) described by the traditional CAPM is not as steeply sloped as the CAPM model predicts and that tests of the CAPM have measured the extent to which security returns and betas are related as predicted by the CAPM that confirms its validity. Thus, he asserts ECAPM should be used in the CAPM analysis.[38]

Q. WHY IS THE ECAPM EXCLUDED FROM YOUR ANALYSIS?

A. The ECAPM is a modified version of the CAPM which attempts to address the belief that the actual risk vs. return correlation is flatter than what is predicted by the CAPM. The implication is that the CAPM underestimates returns with lower levels of risk and overestimates the returns associated with higher levels of risk. The model entails assigning a 25% weight to the market beta and a 75% weight to the individual company or proxy group.[39]

Additionally, the use of the ECAPM in estimating the cost of capital does not increase the validity of the result but merely adds another measure of subjectivity to the CAPM in an attempt to make the SML more accurate. The ECAPM reduces the purpose of the beta, which is the only company-specific

[38] Joint Statement No. 2R, pp. 21-23.
[39] David C. Parcell, "The Cost of Capital - A Practitioner's Guide," 2020 Edition, p. 106.

variable in the CAPM model. This additional layer of subjectivity provides an even stronger basis to rely on the DCF as the primary method to calculate a utility's cost of equity. In fact, as discussed in my direct testimony,[40] Mr. D'Ascendis inflated his traditional CAPM result of 10.96% by simply combining the ECAPM results to produce the indicated CAPM cost of equity rate of 11.12%.

Lastly, I am unaware of whether the Commission has specifically recognized or approved ECAPM results in a cost of equity determination.

Q. ARE YOU CHANGING YOUR CAPM RETURN ON EQUITY RECOMMENDATION AS A RESULT OF MR. D'ASCENDIS'S REBUTTAL TESTIMONY?

A. No. I continue to recommend using my traditional CAPM result of 10.51% and CAPM result using Kroll's ERP of 9.36% (with an average of both CAPM results of 9.94%)[41] only as a comparison to my DCF result of 10.51%.[42]

NON-PRICE REGULATED PROXY GROUP

Q. WHAT WAS YOUR RECOMMENDATION IN DIRECT TESTIMONY CONCERNING MR. D'ASCENDIS'S USE OF A NON-REGULATED PROXY GROUP?

A. I recommended that the Commission reject all analyses performed using the non-

[40] I&E Statement No. 2, pp. 47-48.
[41] I&E Exhibit No. 2, Schedule 11.
[42] I&E Exhibit No. 2, Schedule 6.

price regulated company proxy group as it is highly speculative and subjective. Mr. D'Ascendis's non-price regulated proxy group in effect blends the CE approach into the DCF, CAPM, and RP models.[43]

Q. SUMMARIZE MR. D'ASCENDIS'S RESPONSE REGARDING YOUR DISAGREEMENT WITH HIS USE OF A NON-PRICE REGULATED PROXY GROUP.

A. In rebuttal testimony,[44] Mr. D'Ascendis attempts to justify the use of the companies in his non-price regulated proxy group based on the unadjusted betas and standard errors of the regression being similar to that of the companies in his gas company proxy group. Therefore, he opines that they are comparable to Valley in the context of total risks (business risk and financial risk). He admits that business risk and financial risk may vary between companies and proxy groups. However, he claims that if the collective average betas and standard errors of the regression of the proxy group are similar, then the total non-diversifiable market risks and diversifiable risks are similar as noted in an academic article entitled, "Comparable Earnings - New Life for an Old Precept."[45] He then concludes that the non-price regulated companies are selected based on analyses of market data, and hence, they are comparable in total risk (even though

[43] I&E Statement No. 2, pp. 14-15.
[44] Joint Statement No. 2R, p. 27.
[45] Joint Statement No. 2R, p. 27.

individual risks may vary) to his gas utility proxy group.[46] Finally, he concludes that the results of market models applied to the non-price regulated proxy group are comparable in total risk to his gas utility proxy group, and therefore, should be accepted by the Commission.[47]

Q. HAS MR. D'ASCENDIS PROVEN THAT THE RISKS FACED BY HIS NON-PRICE REGULATED PROXY GROUP ARE SIMILAR TO THAT OF HIS GAS UTILITY PROXY GROUP?

A. No. The risks faced in each industry for the companies used in Mr. D'Ascendis's non-price regulated group differ from the risks faced by his gas utility group. Specifically, the level of competition between non-price regulated companies and monopolies, which utilities largely are, is too difficult a factor to control. Although beta is an indicator of a company's investment risk in relation to the entire stock market, beta is not a quantification of the total investment risk of a given company. Mr. D'Ascendis's unregulated proxy group may have a beta comparable to that of his gas proxy group, but that does not mean the companies face sufficiently similar risks and uncertainties to be used as a substitute for an industry's market. Both beta and the standard error of regression are measures of the past performance of a stock and as such do not necessarily reflect where an industry is going or what risks it is expected to face.

[46] Joint Statement No. 2R, p. 28.
[47] Joint Statement No. 2R, p. 30.

Additionally, the Commission made the following comments in the 2017 UGI Electric case regarding the CE method, specifically for the use of non-utility (unregulated) companies as comparable groups, and stated,[48]

> With respect to the CE method, as noted above, this cost of equity method utilizes data for non-regulated firms. Thus, by its very nature, determining which companies are comparable is entirely subjective. In addition, the record indicates that the companies UGI utilized in its CE group results in the selection of companies such as Coca-Cola Company, Kellogg Company, and Walmart Stores, Inc.…Each of these companies operate in industries that are very different from a utility company and have significantly more competition, which would require a higher return for the associated additional risk.

As discussed in my direct testimony,[49] I reiterate that non-price regulated or non-utility companies with unrelated or entirely dissimilar business segments are simply not comparable to gas distribution utilities in terms of business risk and financial risk profiles. Natural gas distribution utilities are monopolies that are subject to very little competition, if any at all. Due to this minimal competition, natural gas distribution utilities in general have very low business risk and can maintain higher financial risk profiles by employing more leverage. Conversely, since the companies in Mr. D'Ascendis's non-price regulated proxy group operate in an unregulated competitive environment with a higher level of business risks

[48] *Pa. PUC v. UGI Utilities, Inc. - Electric Division,* Docket No. R-2017-2640058 (Order Entered October 25, 2018), p. 105. The Commission has also ruled "[t]he use of nonregulated companies as a comparable group for regulated firms requires numerous unsupportable assumptions which results in a highly speculative finding." *Pennsylvania Public Utility Commission v. Philadelphia Electric Co.* 33 PUR 4th 319, 341 (Pa PUC 1980).

[49] I&E Statement No. 2, pp. 12-14.

and uncertainties, they must maintain lower financial risk profiles by employing a smaller amount of leverage.

Finally, I am advised by counsel that use of a non-price regulated proxy group defies the principle set forth in the *Hope* and *Bluefield cases*[50] that a utility is entitled to a return similar to that being earned by companies with similar risks and uncertainties, but not as high as those earned by highly profitable or speculative ventures.

SIZE ADJUSTMENT

Q. SUMMARIZE YOUR DIRECT TESTIMONY REGARDING MR. D'ASCENDIS'S CLAIM FOR THE COMPANY'S SIZE ADJUSTMENT.

A. In my direct testimony,[51] I discussed that Mr. D'Ascendis's 100-basis point (1.00%) adjustment is unnecessary because none of the technical literature cited in his direct testimony supporting an adjustment related to the size of a company is specific to the utility industry. Additionally, I presented an article by Dr. Annie Wong that demonstrated that there is no need to make an adjustment for the size of a company in utility rate regulation. Finally, I indicated that the Commission has recently rejected the application of a size adjustment to the cost of equity calculation.

[50] *See Bluefield Water Works & Improvements Co. v. Public Service Comm. of West Virginia,* 262 U.S. 679,692-93 (1923), and the *FPC v. Hope Natural Gas Co.,* 320 U.S. 591, 603 (1944).

[51] I&E Statement No. 2, pp. 49-53.

Q. DID ANY WITNESSES RESPOND TO YOUR RECOMMENDED REJECTION OF THE SIZE ADJUSTMENT?

A. Yes. Company witnesses D'Ascendis and Rogers disagree with my recommendation.

Q. SUMMARIZE MR. D'ASCENDIS'S RESPONSE IN REBUTTAL TESTIMONY REGARDING A SIZE RISK FACTOR ADJUSTMENT.

A. Mr. D'Ascendis opines that smaller companies are simply less able to cope with significant events that affect sales, revenues, and earnings. For example, smaller companies face more exposure to business cycles and economic conditions, both nationally and locally. Additionally, he claims that the loss of revenues from a few large customers would have a far greater effect on a small company than on a larger company with a more diverse customer base.[52] He supports these statements by pointing to a study from Fama and French relating the size of a company to its return on equity, which indicates that small capitalization firms are more risky than large capitalization firms.[53] Mr. D'Ascendis also attempts to discredit a study performed by Dr. Wong, that I relied upon in rejecting his size adjustment, by citing a review of her study authored by Thomas M. Zepp.[54] He presents two graphs showing: (1) the relationship between size (measured by capitalization of Value Line utility companies) and risk for the Value Line

[52] Joint Statement No. 2R, p. 8.
[53] Joint Statement No. 2R, pp. 8-9.
[54] Joint Statement No. 2R, p. 9.

universe of utility companies to demonstrate risk variance and (2) the relationship between size and safety ranking for the Value Line universe of utility companies.[55] Finally, Mr. D'Ascendis points to a 2019 Commission order in Citizens Electric case, where he claims that the Commission considered a size adjustment.[56]

Q. SUMMARIZE MR. ROGERS'S RESPONSE IN REBUTTAL TESTIMONY REGARDING A SIZE RISK FACTOR ADJUSTMENT.

A. Mr. Rogers states that Valley has real risk of losing one or more of the largest customers who have access to potential alternatives to natural gas service. Additionally, he states that the Commission has previously approved a size adjustment for small utilities, including Valley. He claims that in 2019 Citizens Electric and Valley cases, the Commission has specifically considered the size of the Company and approved an upward adjustment to the cost of equity by allowing for one standard deviation above the average of the mean and median proxy group ROE of the Company's DCF analysis. He then reiterates Mr. D'Ascendis's opinion that a general inverse relationship exists between size and risk, and the smaller companies like Valley face a greater risk. Therefore, he asserts that a higher return is required to provide the resources to handle significant events that affect revenues, costs, plant, and earnings.[57]

[55] Joint Statement No. 2R, p. 10-11.
[56] Joint Statement No. 2R, p. 12.
[57] Valley Statement No. 4R, pp. 4-6.

Q. ARE THE WITNESSES' ASSERTIONS REGARDING FIRMS OF SMALLER SIZE RELEVANT TO THE REGULATED UTILITY INDUSTRY?

A. No. The study performed by Dr. Wong provides empirical evidence that refutes Mr. D'Ascendis's claim, which I will further elaborate on below. Furthermore, regulated utility companies have the option to file base rate cases to address declining revenues and to recover the increasing cost of doing business in addition to emergency rate relief provisions for large unforeseen impacts. In contrast, non-utility businesses that may be significantly impacted by events of this nature due to small operating size do not have these opportunities. Further, while a smaller utility may pay higher prices for services and materials simply due to low volume buying power, the actual costs are part of the revenue requirement presented by that company. Thus, increasing the equity return to account for the potential size disadvantage would only further unfairly burden ratepayers who are already likely paying higher utility bills to recover the higher operating costs.

Regarding concerns raised related to a revenue deficiency due to potential loss of a few large customers and its consequential effect on financials of a small utility company, I refer to Valley's response to I&E-RR-21, where Valley states that there have been no "large customers" accounts lost or gained in 2022, 2023, and 2024. One Compressed Natural Gas (CNG) station closed in April 2025 and another CNG station is expected to close later this year. However, the April 2025 station closure only affected a small portion of Valley's total revenue with an

average revenue loss of $2,389, and the later station closure would result in an average revenue loss of $1,773.[58]

Q. PLEASE CONTINUE.

A. It is also important to note that the assertion that as a company's size decreases, risk increases, is speculative and not reliable because size measurement is based on the stock price volatility (risk) and market capitalization (size) relationship. Stock price volatility is not an appropriate risk measure as the stock prices are influenced by various factors such as economic conditions, financial and capital market conditions, regulatory changes, company-specific operational and financial risks and uncertainties, and a company's quarterly and annual financial results.

Q. WHAT ARE YOUR OBSERVATIONS REGARDING THE STUDIES MR. D'ASCENDIS RELIES ON TO SUPPORT HIS CLAIM OF A SIZE ADJUSTMENT?

A. The Fama and French study is not specific to the utility industry. While I relied upon the Fama and French study in this proceeding, as Mr. D'Ascendis correctly points out, the purpose for which I cited the study was to demonstrate empirically the shortcomings of the CAPM. The Fama and French study is irrelevant for the determination of the size risk factor because it is not specific to the utility industry.

[58] I&E Exhibit No. 2, Schedule 13.

Q. PLEASE COMMENT ON THE REVIEW OF DR. WONG'S STUDY PERFORMED BY DR. ZEPP.

A. The article Mr. D'Ascendis references from Dr. Zepp does not recreate Dr. Wong's study; it simply speculates on other possible reasons for Dr. Wong's results and references the results of two other studies. The first study, completed by the California Public Utilities Commission Staff in 1991, is not included in the article, and, therefore, Dr. Zepp's opinions cannot be properly evaluated. Dr. Zepp also draws his conclusions about an entire industry based on the second study, which examines the effects of size on only four water utility companies. This article does not contain enough credible evidence to refute Dr. Wong's findings.

Q. HAVE YOU FOUND FURTHER EVIDENCE TO SUPPORT YOUR RECOMMENDATION REGARDING SIZE ADJUSTMENTS?

A. Yes. The difficulty in predicting the risk effect of a company's size is demonstrated in the variance from year to year of the measurement of difference between the annual returns on the large and small-capitalization stocks of the NYSE/AMEX/NASDAQ in the Ibbotson *Stocks, Bonds, Bills & Inflation: 2015 Yearbook.* As stated on page 100,

> While the largest stocks actually declined in 2001, the smallest stocks rose more than 30%. A more extreme case occurred in the depression-recovery year of 1933, when the difference between the first and 10th decile returns was far more substantial. The divergence in the performance of small- and

large- cap stocks is evident. In 30 of the 89 years since 1926, the difference between the total returns of the largest stocks (decile 1) and the smallest stocks (decile 10) has been greater than 25 percentage points.

Page 109 states,

> In four of the last 10 years, large-capitalization stocks (deciles 1-2 of NYSE/AMEX/NASDAQ) have outperformed small-capitalization stocks (deciles 9-10). This has led some market observers to speculate that there is no size premium. But statistical evidence suggests that periods of underperformance should be expected.

Page 112 states,

> Because investors cannot predict when small-cap returns will be higher than large-cap returns, it has been argued that they do not expect higher rates of return for small stocks.

Aswath Damodaran notes in his study "Equity Risk Premiums (ERP):

Determinants, Estimation, and Implications" - The 2022 Edition on page 50 states,

> In the four decades since 1980, the small cap premium has been non-existent, raising questions about whether it still persists or whether it was an artifact of the twentieth century.

Page 51 states,

> Finally, a series of studies have argued that market capitalization, by itself, is not the reason for excess returns but that it is a proxy for other ignored risks such as illiquidity and poor information. The argument that there is, in fact, no small cap premium and that we have observed over time is just an artifact of history that should be given credence.

Page 53-54 states,

> Even if you believe that small cap companies are more exposed to market risk than large cap ones, this is a sloppy and lazy way of dealing with that risk, since risk ultimately has to come from something fundamental (and size is not a fundamental factor).

Q. WHAT IS YOUR RESPONSE TO MR. D'ASCENDIS'S REBUTTAL TESTIMONY REGARDING THE REFERENCED COMMISSION ORDER FOR CITIZENS' ELECTRIC COMPANY?

A. Mr. D'Ascendis admits that the Commission did not make an explicit size adjustment in the Citizens' Electric proceeding, however, he states that the Commission did acknowledge that size is a factor in assessing a company's ability to attract capital. He then claims that the Commission adjusted the DCF result by one standard deviation of the mean and median to account for size.[59] Although the Commission in the Citizens' Electric proceeding agreed that there is an inverse relationship between size and risk, the Commission concluded that there is no substantial evidence that size is specifically a risk for utilities as follows,

> At the same time, however, we echo the ALJs that the Parties have presented offsetting arguments such that there is not substantial evidence to determine whether size is specifically a risk for utilities. As I&E and the OCA both noted, the technical literature presented by Citizens' is not specific to the utility industry and also may not definitively support a size adjustment. Additionally, as I&E observed, the empirical study undertaken by the Company's witness Mr. D'Ascendis illustrates the difficulty in predicting the risk effect of a company's size. More specifically, while Mr. D'Ascendis used market information from the NYSE, the AMEX, and the NASDAQ, we find that I&E offered evidence indicating that for certain periods, large-capitalization stocks have outperformed small-capitalization stocks such that there is not sufficient correlation to prove that size is a specific risk for utilities. I&E St. 2-SR at 23-24. Therefore, we are not persuaded by the Company's argument that the ALJs erred by not awarding Citizens' a greater size adjustment. For this

[59] Joint Statement No. 2R, p. 12.

reason, we decline to award an explicit 100-basis point size adjustment, as advocated by Citizens.[60]

Similarly, in the 2019 Valley Energy case the Commission rejected 100-bassis point size adjustment.[61] The Commission has also rejected the application of a size adjustment to the CAPM cost of equity calculation where it agreed that the literature the company cites is not specific to the utility industry.[62]

Q. HAS YOUR RECOMMENDATION REGARDING MR. D'ASCENDIS AND MR. ROGERS'S SIZE ADJUSTMENT CHANGED SINCE YOUR DIRECT TESTIMONY?

A. No. I continue to recommend that any adjustments in consideration of the Company's size be disallowed for the reasons explained above and in my direct testimony.

MANAGEMENT PERFORMANCE POINTS

Q. SUMMARIZE MR. D'ASCENDIS AND MR. ROGERS'S REBUTTAL TESTIMONY REGARDING MANAGEMENT PERFORMANCE POINTS.

A. Mr. D'Ascendis simply states that the Company should be awarded a five-basis point (0.05%) upward adjustment to its indicated ROE based on Code 66 Pa. C.S.

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60 *Pa. PUC v. Citizens Electric Company of Lewisburg, PA,* Docket No. R-2019-3008212 (Order Entered April 29, 2020). *See generally* Disposition of Cost of Common Equity, pp. 103-104.

61 I&E Statement No. 2, p. 52-53. *Pa. PUC v. Valley Energy, Inc*., Docket No. R-2019-3008209 (Order Entered April 27, 2020), p. 114 (Disposition of Cost of Common Equity).

62 *Pa. PUC v. UGI Utilities, Inc. – Electric Division*, Docket No. R-2017-2640058 (Order Entered October 25, 2018), p. 100 (Disposition of Cost of Common Equity).

§ 523 regarding performance factor.[63] He further states, "Simply put, Code 66 Pa. C.S. § 523 is in existence to incentivize companies to 'do their job' at a high level. The Companies in this case fulfill the requirement of the statute and should receive the benefit of doing so."[64] He does not offer an explanation beyond what he argued in his direct testimony.

Mr. Rogers reiterates most of Mr. D'Ascendis's reasons from his direct testimony to support the Company's claim for a performance adjustment. These reasons include smart hub online account access to its customers, replacement of 100% of its cast iron and bare steel mains, replacement of leak prone Aldyl-A vintage plastic pipelines and service lines, reduced lost and unaccounted for gas, outstanding emergency response, low customer complaints, etc.[65] Finally he states that based on the above improvements and continued efficiencies, the Company has been able to provide overall cost savings in excess of $452,000 or $61 annually per customer. Therefore, he asserts that Valley has earned a performance adjustment based on the Company's achievements and initiatives as outlined above and in his direct testimony.[66]

[63] Joint Statement No. 2R, p. 13.
[64] Joint Statement No. 2R, p. 13.
[65] Joint Statement No. 4R, pp. 3-4.
[66] Joint Statement No. 4R, p. 4.

Q. WHAT IS YOUR RESPONSE TO MR. D'ASCENDIS AND MR. ROGERS'S REBUTTAL TESTIMONY REGARDING MANAGEMENT PERFORMANCE?

A. My position remains unchanged from the arguments made in my direct testimony.[67] Awarding the Company management effectiveness points would add an increased cost to ratepayers for service. Furthermore, any savings from effective operating and maintenance cost measures should flow through to ratepayers and investors. These claimed savings would likely be offset by the addition of basis points for management effectiveness as ratepayers would have to fund the additional costs. This defeats the purpose of implementing cost saving measures to benefit ratepayers.

Additionally, the Company should not be awarded management performance points in order to provide a sufficient return on equity or to affect investment decisions and planning for future financial activities, including the timing of rate cases. The purpose of base rate cases is to allow a utility to recover its costs and provide it the *opportunity* to earn a reasonable return on capital investments where additional basis points for management performance would not be necessary if management was as effective as they claim.

[67] I&E Statement No. 2, pp. 54-59.

Finally, as discussed in my direct testimony, true management effectiveness is earning a higher return through efficient use of resources and cost cutting measures. The greater net income resulting from cost savings and true efficiency in management and operations is available to be passed on to shareholders. Many of the topics presented by the Company fall within the categories of safe and reliable customer service and satisfaction required of every public utility under 66 Pa C.S.A. §1501. There is no basis or support for the addition of five basis points (0.05%) for superior or exemplary management performance. Valley, or any utility, should not be awarded additional basis points for doing what they are required to do to provide adequate, efficient, safe, and reasonable service under 66 Pa C.S.A. §1501.

SUMMARY OF MR. WALTERS' REBUTTAL TESTIMONY

Q. SUMMARIZE MR. WALTERS' RESPONSE TO YOUR ROE RECOMMENDATION.

A. Mr. Walters raises concerns for my: (1) recommended ROE of 10.51% because he claims that this ROE is the highest allowed for natural gas utility since at least 2017; (2) use of constant growth DCF model, which he claims based on excessive growth rates; and (3) recommended ROE which he opines is subject to significant biases and lacks thoroughness because it is based on a single model.[68]

[68] OCA Statement No. 2-R, pp. 3-4.

BENCHMARKING ROE

Q. SUMMARIZE MR. WALTERS'S RESPONSE TO YOUR RECOMMENDED ROE CHARACTERIZING IT AS INCONSISTENT WITH HIS BENCHMARK.

A. Mr. Walters states that my recommended ROE of 10.51% is inconsistent with and a deviation from all relevant benchmarks. He relies on the S&P Global research data point and points to the 2024 annual average authorized ROE of 9.70% for natural gas utilities and states that only in 2010 did an industry-wide average ROE briefly exceed 10%. Further, he adds that since 2017, Atlanta Gas Light Company has been awarded a 10.55% ROE.[69] Considering this, he concludes that my recommended 10.51% places Valley at the upper end of the spectrum and is inconsistent with industry norms or benchmarks for a regulated gas distribution utility and recommends that my recommended ROE be rejected.[70]

Q. WHAT IS YOUR RESPONSE TO MR. WALTERS'S BENCHMARKING YOUR RECOMMENDED ROE WITH THE NATIONAL AVERAGE ROE FOR NATURAL GAS UTILITIES?

A. As discussed at length in my direct testimony concerning use of appropriate cost of equity methods,[71] I performed the cost of equity analysis (DCF and CAPM) using the latest available market data of the gas utility proxy group at the time of

[69] OCA Statement No. 2-R, p. 4.
[70] OCA Statement No. 2-R, p. 5.
[71] I&E Statement No. 2, pp. 19-27.

my analysis. The DCF and CAPM analysis are traditionally used, industry-wide and Commission accepted, and the trusted formula-based method. I have not maneuvered or altered market data that I used in my analysis. Historically, the Commission has accepted and approved I&E analysis results based on the DCF and CAPM methodologies as presented in base rate cases. I&E has not deviated from these traditional DCF and CAPM analysis methods. Therefore, it is inappropriate to compare I&E's market-driven data analysis results with other state jurisdictional utilities' ROE analysis methods and results.

USE OF GROWTH RATES

Q. SUMMARIZE MR. WALTERS'S RESPONSE TO YOUR GROWTH RATES USED IN YOUR CONSTANT GROWTH DCF MODEL.

A. Mr. Walters disputes the analysts' forecasted growth rate of 6.87% used in my DCF analysis because this rate exceeds the consensus for a long-term 4.09% GDP growth rate of the United States by 278 basis points.[72] He asserts that the United States GDP growth projection is a reasonable upper limit, or proxy, for the maximum sustainable long-term growth rate in the DCF model because public utilities cannot indefinitely sustain a growth rate that exceeds the growth rate of the economy in which they sell services.[73] Therefore, he asserts that my constant growth DCF analysis is flawed and suggests consideration of a widely used multi-

[72] OCA Statement No. 2-R, p. 7.
[73] OCA Statement No. 2-R, p. 7.

stage DCF model to balance my result.[74] Finally, he concludes that assuming a multi-stage DCF result of 8.62%, the average of my constant growth DCF and multi-stage DCF analyses would be 9.57% [(10.51% + 8.62%) ÷ 2], which is consistent with his recommended ROE of 9.50% for Valley.[75]

Q. WHAT IS YOUR RESPONSE TO MR. WALTERS'S COMMENT ON USE OF ANALYSTS' FORECASTED GROWTH RATES IN THE CONSTANT GROWTH DCF MODEL AND HIS SUGGESTION TO USE MULTI-STAGE DCF MODEL IN DETERMINING THE ROE FOR VALLEY?

A. As discussed in my direct testimony and data presented in my exhibit,[76] I used a five-year earnings growth forecast estimate of S&P Global, Zacks, and Value Line for my proxy group companies, which results in an average growth rate of 6.87%. Notably, S&P Global, Zacks, and Value Line forecasted earnings growth rates are based on in-depth data research and consider company and industry specific data points and growth potentials as well as external factors such as capital market, inflation, investor sentiments, and the economy in forecasting a utility's earnings growth forecast. Thus, the analyst forecasted growth rates are widely used and accepted by the industry, investors, utility regulators, and the capital market. Analysts' forecasted earnings growth rates reflect a true representation of proxy group companies' growth rates rather than the U.S. Gross Domestic Product

[74] OCA Statement No. 2-R, p. 8.
[75] OCA Statement No. 2-R, p. 9.
[76] I&E Statement No. 2, p. 21 and I&E Exhibit No. 2, Schedule 5.

(GDP) growth rates. The DCF method has the most wide-spread regulatory acceptance, and the Commission has historically relied mostly upon the constant growth DCF results with analysts' forecasted growth rates in base rate proceedings as recently as 2017, 2018, 2020, and 2021.[77]

The U.S. GDP growth rate is not a market measure, rather it is a measure of the value of the total output of goods and services excluding inflation in an economy. GDP is the sum of all private industry and government output in the United States, and its growth rate is simply an average of the value of those industries. The GDP growth rate is measured using a basket of a variety of goods and services produced in the country, which does not truly represent or is not comparable with industry specific or gas utilities' growth rates. Some industries grow faster than other industries, while some industries grow slowly or do not grow or remain on a steady growth trajectory, so the specific industry's growth rate should not be measured or compared with the overall GDP growth rate. Therefore, it is inappropriate and speculative to assume that the gas utility growth rates cannot exceed the GDP growth rate. Ironically, Mr. Walters did use a

[77] *Pa. PUC v. City of DuBois - Bureau of Water*, Docket No. R-2016-2554150 (Order Entered March 28, 2017). *See generally* Disposition of Cost Rate Models, pp. 96-97; *Pa. PUC v. UGI Utilities, Inc. - Electric Division,* Docket No. R-2017-2640058 (Order Entered October 25, 2018). *See generally* Disposition of Cost of Common Equity, p. 119; *Pa. PUC v. Wellsboro Electric Company,* Docket No. R-2019-3008208 (Order Entered April 29, 2020). *See generally* Disposition of Primary Methodology to Determine ROE, pp. 80-81; *Pa. PUC v. Citizens Electric Company of Lewisburg, PA,* Docket No. R-2019-3008212 (Order Entered April 29, 2020). *See generally* Disposition of Cost of Common Equity, pp. 91-92; *Pa. PUC v. Columbia Gas of Pennsylvania, Inc.,* Docket No. R-2020-3018835 (Order Entered February 19, 2021). *See generally* Disposition of Cost of Common Equity, p. 131; , Docket No. R-2020-3018929 (Order Entered June 22, 2021). See generally Disposition of Return of Rate on Common Equity, p. 171.

consensus analysts' (Zacks, S&P, and I/B/E/S) average growth rate of 6.87% in his constant growth DCF model.[78]

It is important to note that my DCF analysis uses the proxy group companies' spot dividend yield, a 52-week dividend yield, and five-year earnings growth forecasts, which provides a forward-looking estimation for the cost of equity that would be more appropriate and consistent with FPFTY ratemaking.

Considering the above, I disagree with Mr. Walters' characterization that my constant growth DCF analysis result is flawed and his suggestion to consider a multi-stage DCF model in my DCF analysis. I also disagree with Mr. Walters's calculated average of my constant growth DCF and his multi-stage DCF analyses result of 9.57% [(10.51% + 8.62%) ÷ 2].

EXCLUSIVE RELIANCE ON THE DCF

Q. SUMMARIZE MR. WALTERS'S RESPONSE TO YOUR EXCLUSIVE RELIANCE ON THE CONSTANT-GROWTH DCF MODEL.

A. Mr. Walters states that no single model can be relied upon exclusively to estimate a fair and reasonable cost of equity because each model has its own strengths, limitations, and sensitivities to input assumptions. He claims that my exclusive use of a constant growth DCF model fails to capture the full range of investor expectations because it is highly sensitive to the assumed growth rate and exceeds

[78] OCA Exhibit CCW-3.

the projected growth rate of the U.S. economy by a significant margin. Therefore, he advocates for the use of a multi-model approach, such as including a multi-stage DCF, CAPM, and RP method.[79]

Q. WHAT IS YOUR RESPONSE TO MR. WALTERS'S COMMENT ON YOUR EXCLUSIVE RELIANCE ON A CONSTANT-GROWTH DCF MODEL AND HIS SUGGESTION TO USE MULTI-MODEL APPROACH?

A. For the reasons discussed in the "Sole Reliance on DCF" section above in response to Mr. D'Ascendis's comment concerning my exclusive use of the DCF model in determining the cost of equity for Valley, I disagree with Mr. Walters's assertions that the DCF model fails to capture the full range of investor expectations and that the use of analysts' growth rates in the DCF model is inappropriate because it is higher than the GDP growth rate. Additionally, the Commission has accepted and relied on I&E's DCF methodology (using analysts' forecasted growth rates) and DCF results in several rate cases cited above in determining the appropriate and reasonable ROE for utilities.

[79] OCA Statement No. 2-R, pp. 9-10.

OVERALL RATE OF RETURN

Q. HAS YOUR OVERALL RATE OF RETURN RECOMMENDATION CHANGED FROM YOUR DIRECT TESTIMONY?

A. No. I continue to support each recommendation made in my direct testimony.[80]

Q. PLEASE RESTATE YOUR RATE OF RETURN RECOMMENDATION?

A. I continue to recommend the following rate of return for the Company:[81]

I&E Recommendation
Valley Energy, Inc.
Summary of Cost of Capital

Type of Capital	Ratio	Cost Rate	Weighted Cost Rate
Long-Term Debt	51.06%	5.03%	2.57%
Common Equity	48.94%	10.51%	5.14%
Total	**100.00%**		**7.71%**

Q. DOES THIS CONCLUDE YOUR SURREBUTTAL TESTIMONY?

A. Yes.

[80] I&E Statement No. 2.
[81] I&E Statement No. 2, pp. 6-7.

I&E Statement No. 3-SR
Witness: Esyan A. Sakaya

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

VALLEY ENERGY, INC.

Docket No. R-2025-3054393

Surrebuttal Testimony

of

Esyan A. Sakaya

Bureau of Investigation and Enforcement

Concerning:

Revenue Requirement
Reporting Requirements
Scale Back of Rates

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INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Esyan A. Sakaya. My business address is Pennsylvania Public Utility Commission, Commonwealth Keystone Building, 400 North Street, Harrisburg, Pennsylvania 17120.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by the Pennsylvania Public Utility Commission (Commission) in the Bureau of Investigation & Enforcement (I&E) as a Fixed Utility Valuation Engineer.

Q. ARE YOU THE SAME ESYAN A. SAKAYA WHO IS RESPONSIBLE FOR THE DIRECT TESTIMONY CONTAINED IN I&E STATEMENT NO. 3?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR SURREBUTTAL TESTIMONY?

A. The purpose of my surrebuttal testimony is to respond to the rebuttal testimony submitted on behalf of Valley Energy, Inc. (Valley or Company) by Howard Gorman (Valley Statement No. 1-R) and Jamie Beale (Valley Statement No. 5-R). My surrebuttal testimony specifically addresses the issues of reporting requirements and the scale back of rates.

Q. DOES YOUR SURREBUTTAL TESTIMONY INCLUDE AN EXHIBIT?

A. No.

REVENUE REQUIREMENT

Q. WHAT WAS THE COMPANY'S INITIAL REQUESTED INCREASE?

A. The Company's initial revenue requirement claim was $1,626,099.[1]

Q. HAS THE COMPANY REVISED ITS REQUESTED INCREASE?

A. Yes. The Company revised its requested increase claim from $1,626,099 to $1,285,942.[2]

Q. WHY DID THE COMPANY REVISE ITS REQUESTED INCREASE?

A. Valley accepted recommended adjustments related to the state income tax expense rate, regulatory commission expense, depreciation expense, the gas cost rate, insurance, and advertising.[3]

[1] Valley Exhibit HSG-1, Sch. C1.
[2] Valley Statement No. 1-R, p. 2.
[3] Valley Statement 1-R, p. 2.

REPORTING REQUIREMENTS

Q. WHAT DID YOU RECOMMEND REGARDING PLANT ADDITIONS THAT THE COMPANY PROJECTS TO BE IN SERVICE DURING THE FTY ENDING DECEMBER 31, 2025 AND THE FPFTY ENDING DECEMBER 31, 2026?

A. In my direct testimony I recommended that the Company be required to provide the I&E and the Office of Consumer Advocate with an update to Valley Exhibit HSG-1, Schedule C3 no later than April 1, 2026, under this docket number, which should include actual capital expenditures, plant additions, and retirements by month for the year ending December 31, 2025. I also recommended that the Company be required to provide an additional update for actuals through December 31, 2026, no later than April 1, 2027.[4]

Q. DID THE COMPANY RESPOND TO YOUR PLANT ADDITIONS AND REPORTING REQUIREMENT RECOMMENDATIONS?

A. Yes. The Company accepted my recommendation.[5]

[4] I&E Statement No. 3, pp. 8-9.
[5] Valley Statement No. 5-R, p. 5.

SCALE BACK OF RATES

Q. WHAT IS THE IMPACT OF VALLEY REDUCING ITS REQUESTED REVENUE INCREASE FROM $1,626,099 TO $1,285,942?

A. By virtue of Valley revising its requested increase from $1,626,099 to $1,285,942, the revised increases by customer class range between 22% and 25%, which is lower than Valley's initial 29% to 32% as shown below in Table 1.

Table 1

AS FILED Source: Valley Exhibit HSG-1, Schedule B4, p. 1			REVISED Source: Valley Exhibit HSG-1R, Schedule B4 (R), p. 1		
Rate Class	Proposed Increase Revenue	Proposed Increase Percentage	Rate Class	Proposed Increase Revenue	Proposed Increase Percentage
Residential:			**Residential:**		
Rate-R	$933,998	29.56%	Rate-R	$738,632	23.38%
Subtotal Residential	**$933,998**		**Subtotal Residential**	**$738,632**	
Commercial:			**Commercial:**		
Rate C - Commercial	$270,382	29.73%	Rate C - Commercial	$215,250	22.88%
Rate IS - Interruptible Service	$5,926	29.28%	Rate IS - Interruptible Service	$4,720	23.33%
Rate SI - Small Industrial	$4,184	27.80%	Rate SI - Small Industrial	$3,468	23.05%
Subtotal Commercial	**$280,491**	28.73%	**Subtotal Commercial**	**$223,439**	22.89%
Transportation:			**Transportation:**		
Firm	$107,445	29.64%	Firm	$84,805	23.39%
Firm-Fixed	$0	0.00%	Firm-Fixed	$0	0.00%
Firm-Volumetric	$0	0.00%	Firm-Volumetric	$0	0.00%
Firm-DDQ	$90,410	32.35%	Firm-DDQ	$70,048	25.06%
Large Industrial	$106,434	29.56%	Large Industrial	$84,176	23.38%
Interrruptible	$107,333	28.58%	Interrruptible	$84,856	23.38%
Subtotal Transportation	**$411,623**	17.54%	**Subtotal Transportation**	**$323,885**	13.80%
Total	**$1,626,112**	**25.08%**	**Total**	**$1,285,956**	**19.84%**

Q. DID VALLEY CHANGE ITS PROPOSED CUSTOMER CHARGES?

A. No. While Valley's revision to its revenue requirement reduced the percentage increases per rate class, the Company is still proposing the same monthly customer

charges. The proposed customer charges and usage rates are shown on Valley Exhibit HSG-1, Schedule B4-R, p. 1.

Q. WHAT DID YOU RECOMMEND IF THE COMMISSION GRANTS LESS THAN THE FULL INCREASE?

A. I recommended that if the Commission grants less than Valley's full requested increase, the percentage increase for each class be adjusted so each class, other than the Contract classes, receive the same percentage increase. I also recommended that the customer charges be included in the scale back to limit the increase in the customer charge that is applicable to zero and low usage customers.[6]

Q. WHY DID YOU RECOMMEND THAT EACH CLASS BESIDES THE CONTRACT CLASSES RECEIVE THE SAME PERCENTAGE INCREASE?

A. Valley did not provide a cost of service study to compare the revenue received to the expenses incurred to provide service to each class. Thus, there is no justification for proposing different percentage increases for the classes receiving an increase. Therefore, scaling back the rates so each class receives the same percentage increase is the most reasonable approach to establish rates if the Commission grants less than the full increase.

[6] I&E Statement No. 3, pp. 8-9.

Q. DID THE COMPANY RESPOND TO YOUR SCALE BACK RECOMMENDATION?

A. Yes. The Company agreed with my scale back recommendation with respect to the percentage increases, but it did not agree with my recommendation to include the customer charge in the scale back.[7]

Q. DO YOU AGREE THAT THE CUSTOMER CHARGE NOT BE INCLUDED IN THE SCALE BACK?

A. No, I continue to recommend that the customer charge be included in any scale back.

Q. PLEASE EXPLAIN.

A. As stated in my direct testimony, I recommended that any scale back include the customer charges for the following reasons. First, zero and low usage customers should be included in the scale back in order to limit the increase in the customer charge. Second, including the customer charge in the scale back promotes conservation because it causes a larger portion of the customer's bill to be recovered in volumetric rates, thus giving customers more of an incentive to reduce usage. Finally, adjustments resulting in a reduced revenue requirement

[7] Valley Statement No-1-R, pp. 6-7.

would also affect those items that are included in the customer costs, so any scale back related to a lower revenue allowance should also apply to customer charges.[8]

Q. DOES THIS CONCLUDE YOUR SURREBUTTAL TESTIMONY?

A. Yes.

[8] I&E Statement No. 3, p. 9.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No.: R-2025-3054393
	:	
Valley Energy, Inc.	:	
Base Rate Case	:	

WITNESS VERIFICATION
THE BUREAU OF INVESTIGATION AND ENFORCEMENT

I, Christine S. Wilson, on behalf of the Bureau of Investigation and Enforcement, hereby verify that the documents preliminarily identified as:

- I&E Statement No. 1;
- I&E Exhibit No. 1;
- I&E Statement No. 1-SR.

were prepared by me or under my direct supervision and control. Furthermore, the facts contained therein are true and correct to the best of my knowledge, information and belief and I expect to be able to prove the same at an Evidentiary Hearing in this matter. This Verification is made subject to the penalties of 18 Pa. C.S. § 4904 relating to unsworn falsification to authorities.

Christine S. Wilson

Christine S. Wilson
Pennsylvania Public Utility Commission
Bureau of Investigation and Enforcement

Dated: September 3, 2025

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No.: R-2025-3054393
	:	
Valley Energy, Inc.	:	
Base Rate Case	:	

WITNESS VERIFICATION
THE BUREAU OF INVESTIGATION AND ENFORCEMENT

I, D. C. Patel, on behalf of the Bureau of Investigation and Enforcement, hereby verify that the documents preliminarily identified as:

- I&E Statement No. 2;
- I&E Exhibit No. 2; and
- I&E Statement No. 2-SR.

were prepared by me or under my direct supervision and control. Furthermore, the facts contained therein are true and correct to the best of my knowledge, information and belief and I expect to be able to prove the same at an Evidentiary Hearing in this matter. This Verification is made subject to the penalties of 18 Pa. C.S. § 4904 relating to unsworn falsification to authorities.

/s/ DCPatel
D. C. Patel
Pennsylvania Public Utility Commission
Bureau of Investigation and Enforcement

Dated: September 2, 2025

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No.: R-2025-3054393
	:	
Valley Energy, Inc.	:	
Base Rate Case	:	

WITNESS VERIFICATION
THE BUREAU OF INVESTIGATION AND ENFORCEMENT

I, Esyan A. Sakaya, on behalf of the Bureau of Investigation and Enforcement, hereby verify that the documents preliminarily identified as:

- I&E Statement No. 3; and
- I&E Statement No. 3-SR.

were prepared by me or under my direct supervision and control. Furthermore, the facts contained therein are true and correct to the best of my knowledge, information and belief and I expect to be able to prove the same at an Evidentiary Hearing in this matter. This Verification is made subject to the penalties of 18 Pa. C.S. § 4904 relating to unsworn falsification to authorities.

/s/ Esyan A. Sakaya
Esyan A. Sakaya
Pennsylvania Public Utility Commission
Bureau of Investigation and Enforcement

Dated: September 3, 2025

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	**:**		
	:		
v.	**:**	**Docket Nos.**	**R-2025-**
	:		**R-2025-**
Citizens' Electric Company of Lewisburg, PA,	**:**		
Valley Energy, Inc., and Wellsboro	**:**		
Electric Company	**:**		

DIRECT TESTIMONY

AND EXHIBIT

OF

DYLAN W. D'ASCENDIS

ON BEHALF OF

CITIZENS' ELECTRIC COMPANY OF LEWISBURG, PA,
VALLEY ENERGY, INC., AND
WELLSBORO ELECTRIC COMPANY

APRIL 30, 2025

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I. INTRODUCTION

Q. WOULD YOU PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Dylan W. D'Ascendis. My business address is 1820 Chapel Ave., W., Suite 300, Cherry Hill, N.J. 08003.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am a Partner at ScottMadden, Inc.

Q. PLEASE SUMMARIZE YOUR PROFESSIONAL EXPERIENCE AND EDUCATIONAL BACKGROUND.

A. I have offered expert testimony on behalf of investor-owned utilities before over 40 state regulatory commissions in the United States, the Federal Energy Regulatory Commission, the Alberta Utility Commission, the Canadian Energy Regulator, an American Arbitration Association panel, and the Superior Court of Rhode Island on issues including, but not limited to, common equity cost rate, rate of return, valuation, capital structure, class cost of service, and rate design.

On behalf of the American Gas Association ("AGA"), I calculate the AGA Gas Index, which serves as the benchmark against which the performance of the American Gas Index Fund ("AGIF") is measured on a monthly basis. The AGA Gas Index and AGIF are a market capitalization weighted index and mutual fund, respectively, comprised of the common stocks of the publicly traded corporate members of the AGA.

I am a member of the Society of Utility and Regulatory Financial Analysts ("SURFA"). In 2011, I was awarded the professional designation "Certified Rate

of Return Analyst" by SURFA, which is based on education, experience, and the successful completion of a comprehensive written examination.

I am also a member of the National Association of Certified Valuation Analysts ("NACVA") and was awarded the professional designation "Certified Valuation Analyst" by the NACVA in 2015.

I am a graduate of the University of Pennsylvania, where I received a Bachelor of Arts degree in Economic History. I have also received a Master of Business Administration with high honors and concentrations in Finance and International Business from Rutgers University.

The details of my educational background and expert witness appearances are included in Appendix A.

II. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is to present evidence on behalf of Valley Energy, Inc. ("Valley"), Citizens' Electric Company of Lewisburg, PA ("Citizens'"), and Wellsboro Electric Company ("Wellsboro") (collectively, "the Companies") supporting the appropriate return on common equity ("ROE") for each company's jurisdictional rate base.

Q. HAVE YOU PREPARED AN EXHIBIT IN SUPPORT OF YOUR RECOMMENDATION?

A. Yes. I have prepared Exhibit __ (DWD-1), which consists of Schedules DWD-1 through DWD-8.

III. SUMMARY

Q. WHAT ARE YOUR RECOMMENDED ROES FOR THE COMPANIES?

A. I recommend that the Pennsylvania Public Utility Commission (the "Commission") authorize Valley, Citizens', and Wellsboro opportunities to earn an ROE of 11.65% on their jurisdictional rate bases. These ROEs, as applied to the Companies' ratemaking capital structures and long-term debt cost rates, result in recommended weighted average costs of capital ("WACC") of 8.27%, 8.49% and 8.18% for Valley, Citizens', and Wellsboro, respectively. The Companies' ratemaking capital structures and costs of long-term debt are supported by Company Witness Ryan M. Kucan. The summary of the Companies' requested WACCs are shown on Tables 1, 2, and 3 below.

Table 1: Summary of Recommended Weighted Average Cost of Capital for Valley

Type of Capital	Ratios	Cost Rate	Weighted Cost Rate
Long-Term Debt	51.06%	5.03%	2.57%
Common Equity	48.94%	11.65%	5.70%
Total	100.00%		8.27%

Table 2: Summary of Recommended Weighted Average Cost of Capital for Citizens'

Type of Capital	Ratios	Cost Rate	Weighted Cost Rate
Long-Term Debt	51.06%	5.47%	2.79%
Common Equity	48.94%	11.65%	5.70%
Total	100.00%		8.49%

Table 3: Summary of Recommended Weighted Average Cost of Capital for Wellsboro

Type of Capital	Ratios	Cost Rate	Weighted Cost Rate
Long-Term Debt	51.06%	4.85%	2.48%
Common Equity	48.94%	11.65%	5.70%
Total	100.00%		8.18%

Q. PLEASE SUMMARIZE YOUR RECOMMENDED COMMON EQUITY COST RATES.

A. My recommended common equity cost rates of 11.65% applicable to Valley, Citizens', and Wellsboro are summarized on page 1 of Schedule DWD-1. I have assessed the market-based common equity cost rates of companies of relatively similar, but not necessarily identical, risk to the Companies. Using companies of relatively comparable risk as proxies is consistent with the principles of fair rate of return established in the *Hope*[1] and *Bluefield*[2] decisions. No proxy group can be identical in risk to any single company. Consequently, there must be an evaluation of relative risk between the Companies and the proxy group to determine if it is appropriate to adjust the proxy group's indicated rate of return.

My recommendation results from applying several cost of common equity models, specifically the Discounted Cash Flow ("DCF") model, the Risk Premium Model ("RPM"), and the Capital Asset Pricing Model ("CAPM"), to the market data of a Gas Utility Proxy Group and an Electric Utility Proxy Group (collectively, the "Utility Proxy Groups") whose selection criteria will be discussed below. In

[1] *Federal Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591 (1944*)("Hope").*
[2] *Bluefield Water Works Improvement Co. v. Public Serv. Comm'n*, 262 U.S. 679 (1922).

addition, I applied the DCF model, RPM, and CAPM to proxy groups of domestic, non-price regulated companies comparable in total risk to the Gas and Electric Utility Proxy Groups (collectively, the "Non-Price Regulated Proxy Groups"). The results derived from each are as follows:

Table 4: Summary of Common Equity Cost Rates

	Gas Proxy Group	Electric Proxy Group
Discounted Cash Flow Model	10.29%	10.32%
Risk Premium Model	10.86%	10.79%
Capital Asset Pricing Model	11.12%	10.75%
Cost of Equity Models Applied to Comparable Risk, Non-Price Regulated Companies	11.92%	11.84%
Indicated Range of Common Equity Cost Rates Before Adjustments	10.29% - 11.92%	10.32% - 11.84%
Size Adjustment	1.00%	0.85%
Performance Factor Adjustment	0.05%	0.05%
Indicated Range of Common Equity Cost Rates After Adjustments	11.34% - 12.97%	11.22% - 12.74%
Recommended Cost of Common Equity After Adjustments	11.65%	11.65%

The indicated ranges of common equity cost rates were 10.29% to 11.92% and 10.32% to 11.84% for the Gas and Electric Utility Proxy Groups, respectively, before any company-specific adjustments. I then adjusted the indicated ranges of common equity cost rates upward by 1.00% to reflect Valley's smaller relative size, as compared to the Gas Utility Proxy Group, and by 0.85% to reflect Citizens' and Wellsboro's smaller relative size, as compared to the Electric Utility Proxy Group. I also adjusted the Companies' indicated ranges of common equity cost rates

upward by 0.05% to reflect a performance factor adjustment, based on guidance from Section 523 of the Pennsylvania Public Utility Code, 66 Pa.C.S. § 523, and the Commission Order in the Companies' last litigated rate case.[3] These adjustments resulted in company-specific ranges of common equity cost rates of 11.34% to 12.97% for Valley and 11.22% to 12.74% for Citizens' and Wellsboro. Given the indicated ranges of common equity cost rates for the Companies, I recommend the Commission to approve a common equity cost rate of 11.65% for Valley, Citizens', and Wellsboro.

IV. GENERAL PRINCIPLES

Q. WHAT GENERAL PRINCIPLES HAVE YOU CONSIDERED IN ARRIVING AT YOUR RECOMMENDED COMMON EQUITY COST RATES?

A. In unregulated industries, marketplace competition is the principal determinant of the price of products or services. For regulated public utilities, regulation must act as a substitute for marketplace competition. Assuring that the utility can fulfill its obligations to the public, while providing safe and reliable service at all times, requires a level of earnings sufficient to maintain the integrity of presently invested capital. Sufficient earnings also permit the attraction of needed new capital at a reasonable cost, for which the utility must compete with other firms of comparable risk, consistent with the fair rate of return standards established by the U.S. Supreme Court in the previously cited *Hope* and *Bluefield* cases. The U.S. Supreme Court affirmed the fair rate of return standards in *Hope*, when it stated:

[3] Docket No. R-2019-3008209 (Valley), at 118-120 and R-2019-3008212 (Citizens'), at 108-110.

> The rate-making process under the Act, *i.e.*, the fixing of 'just and reasonable' rates, involves a balancing of the investor and the consumer interests. Thus we stated in the Natural Gas Pipeline Co. case that 'regulation does not insure that the business shall produce net revenues.' 315 U.S. at page 590, 62 S.Ct. at page 745. But such considerations aside, the investor interest has a legitimate concern with the financial integrity of the company whose rates are being regulated. From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock. Cf. Chicago & Grand Trunk R. Co. v. Wellman, 143 U.S. 339, 345, 346 12 S.Ct. 400,402. By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital.[4]

In summary, the U.S. Supreme Court has found a return that is adequate to attract capital at reasonable terms enables the utility to provide service while maintaining its financial integrity. As discussed above, and in keeping with established regulatory standards, that return should be commensurate with the returns expected elsewhere for investments of equivalent risk. Therefore, the Commission's decision in this proceeding should provide the Companies with the opportunity to earn a return that is: (1) adequate to attract capital at reasonable cost and terms; (2) sufficient to ensure their financial integrity; and (3) commensurate with returns on investments in enterprises having corresponding risks.

Lastly, the required return for a regulated public utility is established on a stand-alone basis, i.e., for the utility operating company at issue in a rate case. Parent entities, like other investors, have capital constraints and must look at the attractiveness of the expected risk-adjusted return of each investment alternative in

[4] *Hope*, 320 U.S. 591 (1944), at 603.

their capital budgeting process. That is, utility holding companies that own many utility operating companies have choices as to where they will invest their capital within the holding company family. Therefore, the opportunity cost concept applies regardless of the source of the funding, whether it be public funding or corporate funding.

When funding is provided by a parent entity, the return still must be sufficient to provide an incentive to allocate equity capital to the subsidiary or business unit rather than other internal or external investment opportunities. That is, the regulated subsidiary must compete for capital with all the parent company's affiliates, and with other, similarly situated companies. In that regard, investors value corporate entities on a sum-of-the-parts basis and expect each division within the parent company to provide an appropriate risk-adjusted return.

It therefore is important that the authorized ROE reflects the risks and prospects of the utility's operations and supports the utility's financial integrity from a stand-alone perspective, as measured by its combined business and financial risks. Consequently, the ROE authorized in this proceeding should be sufficient to support the operational (i.e., business risk) and financing (i.e., financial risk) of the Companies on a stand-alone basis.

Q. WITHIN THAT BROAD FRAMEWORK, HOW IS THE COST OF CAPITAL ESTIMATED IN REGULATORY PROCEEDINGS?

A. Regulated utilities primarily use common stock and long-term debt to finance their permanent property, plant, and equipment (i.e., rate base). The fair rate of return for a regulated utility is based on its weighted average cost of capital, in which, as

noted earlier, the costs of the individual sources of capital are weighted by their respective book values with appropriate adjustments.

The cost of capital is the return investors require to make an investment in a firm. Investors will provide funds to a firm only if the return that they *expect* is equal to, or greater than, the return that they *require* to accept the risk of providing funds to the firm.

The cost of capital (that is, the combination of the costs of debt and equity) is based on the economic principle of "opportunity costs." Investing in any asset (whether debt or equity securities) represents a forgone opportunity to invest in alternative assets. For any investment to be sensible, its expected return must be at least equal to the return expected on alternative, comparable risk investment opportunities. Because investments with like risks should offer similar returns, the opportunity cost of an investment should equal the return available on an investment of comparable risk.

Whereas the cost of debt is contractually defined and can be directly observed as the interest rate or yield on debt securities, the cost of common equity must be estimated based on market data and various financial models. Because the cost of common equity is premised on opportunity costs, the models used to determine it are typically applied to a group of "comparable" or "proxy" companies. In the end, the estimated cost of capital should reflect the return that investors require in light of the subject company's business and financial risks, and the returns available on comparable investments.

Q. IS THE AUTHORIZED RETURN SET IN REGULATORY PROCEEDINGS GUARANTEED?

A. No, it is not. Consistent with the *Hope* and *Bluefield* standards, the ratemaking process should provide the utility a reasonable opportunity to recover its return of, and return on, its reasonably incurred investments, but it does not guarantee that return. While a utility may have control over some factors that affect the ability to earn its authorized return (e.g., management performance, operating and maintenance expenses, etc.), there are several factors beyond a utility's control that affect its ability to earn its authorized return. Those may include factors such as weather, the economy, and the prevalence and magnitude of regulatory lag.

A. <u>Business Risk</u>

Q. PLEASE DEFINE BUSINESS RISK AND EXPLAIN WHY IT IS IMPORTANT FOR DETERMINING A FAIR RATE OF RETURN.

A. The investor-required return on common equity reflects investors' assessment of the total investment risk of the subject firm. Total investment risk is often discussed in the context of business and financial risk.

Business risk reflects the uncertainty associated with owning a company's common stock without the company's use of debt and/or preferred stock financing. One way of considering the distinction between business and financial risk is to view the former as the uncertainty of the expected earned return on common equity, assuming the firm is financed with no debt.

Examples of business risks <u>generally</u> faced by utilities include, but are not limited to, the regulatory environment, mandatory environmental compliance

requirements, customer mix and concentration of customers, service territory economic conditions, market demand, risks and uncertainties of supply, operations, capital intensity, size, the degree of operating leverage, emerging technologies including distributed energy resources, and the vagaries of weather.

Although analysts, including rating agencies, may categorize business risks individually, as a practical matter, such risks are interrelated and not wholly distinct from one another. When determining an appropriate return on common equity, the relevant issue is where investors see the subject company in relation to other similarly situated utility companies (i.e., the Utility Proxy Groups). To the extent investors view a company as being exposed to higher risk, the required return will increase, and vice versa.

For regulated utilities, business risks are both long-term and near-term in nature. Whereas near-term business risks are reflected in year-to-year variability in earnings and cash flow brought about by economic or regulatory factors, long-term business risks reflect the prospect of an impaired ability of investors to obtain both a fair rate of return on, and return of, their capital. Moreover, because utilities accept the obligation to provide safe, adequate and reliable service at all times (in exchange for the opportunity to earn a fair return on their investment), they generally do not have the option to delay, defer, or reject capital investments. Because those investments are capital-intensive, utilities generally do not have the option to avoid raising external funds during periods of capital market distress, if necessary.

Because utilities invest in long-lived assets, long-term business risks are of paramount concern to equity investors. That is, the risk of not recovering the return on their investment extends far into the future. The timing and nature of events that may lead to losses, however, also are uncertain and, consequently, those risks and their implications for the required return on equity tend to be difficult to quantify. Regulatory commissions (like investors who commit their capital) must review a variety of quantitative and qualitative data and apply their reasoned judgment to determine how long-term risks weigh in their assessment of the market-required return on common equity.

B. Financial Risk

Q. PLEASE DEFINE FINANCIAL RISK AND EXPLAIN WHY IT IS IMPORTANT IN DETERMINING A FAIR RATE OF RETURN.

A. Financial risk is the additional risk created by the introduction of debt and preferred stock into the capital structure. The higher the proportion of debt and preferred stock in the capital structure, the higher the financial risk to common equity owners (i.e., failure to receive dividends due to default or other covenants). Therefore, consistent with the basic financial principle of risk and return, common equity investors demand higher returns as compensation for bearing higher financial risk.

Q. CAN BOND AND CREDIT RATINGS BE A PROXY FOR A FIRM'S COMBINED BUSINESS AND FINANCIAL RISKS TO EQUITY OWNERS (I.E., INVESTMENT RISK)?

A. Yes, similar bond ratings/issuer credit ratings reflect, and are representative of, similar combined business and financial risks (i.e., total risk) faced by bond

investors.[5] Although specific business or financial risks may differ between companies, the same bond/credit rating indicates that the combined risks are roughly similar from a debtholder perspective. The caveat is that these debtholder risk measures do not translate directly to risks for common equity.

V. VALLEY, CITIZENS', WELLSBORO, AND THE UTILITY PROXY GROUPS

Q. PLEASE SUMMARIZE YOUR KNOWLEDGE OF THE COMPANIES.

A. Valley is an investor-owned natural gas distribution utility that provides natural gas service to customers in Sayre and surrounding communities in Bradford County, which is in the northern tier of Pennsylvania and is predominantly rural. Valley's Pennsylvania operations serve approximately 7,500 customers.

Citizens' is a Pennsylvania corporation with its principal office located in Lewisburg, Union County, Pennsylvania. Citizens' is an investor-owned, for-profit electric distribution utility. Citizens' service territory is a 55-square-mile territory in and around Lewisburg, Pennsylvania. As of February 16, 2023, Citizens' served 7,118 customers, of which 5,913 were residential and 1,205 were commercial, industrial or lighting.[6]

Wellsboro is a small investor-owned electric distribution utility providing service in the Borough of Wellsboro, Pennsylvania and surrounding areas in Tioga County. Wellsboro's approximate 200-square-mile service territory is

[5] Risk distinctions within S&P's bond rating categories are recognized by a plus or minus, e.g., within the A category, an S&P rating can by at A+, A, or A-. Similarly, risk distinction for Moody's ratings are distinguished by numerical rating gradations, e.g., within the A category, a Moody's rating can be A1, A2 and A3.

[6] Source: https://citizenselectric.com/about-us/

predominantly rural. Wellsboro serves 6,478 customers, of which 5,159 were residential and 1,319 were commercial and industrial.[7]

The Companies are wholly-owned by C&T Enterprises, Inc., and are not publicly-traded.

Q. PLEASE EXPLAIN HOW YOU CHOSE THE COMPANIES IN THE GAS UTILITY PROXY GROUP.

A. The companies selected for the Gas Utility Proxy Group met the following criteria:

(i) They were included in the Natural Gas Utility Group of *Value Line Investment Survey's Standard Edition* ("*Value Line*") (February 21, 2025);

(ii) They have 60% or greater of fiscal year 2023 total operating income derived from, or 60% or greater of fiscal year 2023 total assets attributable to, regulated gas distribution operations;

(iii) At the time of preparation of this testimony, they had not publicly announced that they were involved in any major merger or acquisition activity (i.e., one publicly-traded utility merging with or acquiring another) or any other major development;

(iv) They have not cut or omitted their common dividends during the five years ended 2023 or through the time of preparation of this testimony;

(v) They have *Value Line* and Bloomberg Professional Services ("Bloomberg") adjusted beta coefficients ("beta");

(vi) They have positive *Value Line* five-year dividends per share ("DPS") growth rate projections; and

[7] Source: https://wellsboroelectric.com/about-us/

(vii) They have *Value Line*, Zacks, or S&P Capital IQ consensus five-year earnings per share ("EPS") growth rate projections.

The following seven companies met these criteria: Atmos Energy Corporation, New Jersey Resources Corporation, NiSource Inc., Northwest Natural Holding Company, ONE Gas, Inc., Southwest Gas Holdings, Inc., and Spire Inc.

Q. PLEASE EXPLAIN HOW YOU CHOSE THE COMPANIES IN THE ELECTRIC UTILITY PROXY GROUP.

A. The companies selected for the Electric Utility Proxy Group met the following criteria:

(i) They were included in the Eastern, Central, or Western Electric Utility Group of *Value Line*;

(ii) They have 70% or greater of fiscal year 2023 total operating income derived from, and 70% or greater of fiscal year 2023 total assets attributable to, regulated electric operations;

(iii) At the time of preparation of this testimony, they had not publicly announced that they were involved in any major merger or acquisition activity (i.e., one publicly-traded utility merging with or acquiring another) or any other major development;

(iv) They have not cut or omitted their common dividends during the five years ended 2023 or through the time of preparation of this testimony;

(v) They have *Value Line* and Bloomberg adjusted betas;

(vi) They have positive *Value Line* five-year DPS growth rate projections; and

(vii) They have *Value Line*, Zacks, or S&P Capital IQ consensus five-year EPS growth rate projections.

The following 15 companies met these criteria: Alliant Energy Corporation, Ameren Corporation, American Electric Power Company, Inc., Duke Energy Corporation, Edison International, Entergy Corporation, Evergy, Inc., Energy, IDACORP, Inc., NorthWestern Corporation, OGE Energy Corporation, Pinnacle West Capital Corporation, Portland General Electric Company, The Southern Company, TXNM Energy Inc., and Xcel Energy Inc.

Q. PLEASE DESCRIBE PAGES 1 AND 2 OF SCHEDULE DWD-2.

A. Pages 1 and 2 of Schedule DWD-2 contain comparative capitalization and financial statistics for the Gas and Electric Utility Proxy Groups identified above for the years 2019 to 2023.

During the five-year period ending 2023, the historically achieved average earnings rate on book common equity for the Gas and Electric Utility Proxy Groups averaged 8.41% and 9.29%, respectively. Total debt to earnings before interest, taxes, depreciation, and amortization for the years 2019 to 2023 ranged between 4.81 and 5.72, with an average of 5.34 for the Gas Utility Proxy Group, and ranged between 4.73 and 5.98, with an average of 5.41 for the Electric Utility Proxy Group. Funds from operations to total debt ranged from 9.24% to 27.32%, with an average of 15.50% for the Gas Utility Proxy Group, and 6.06% to 13.34% with an average of 10.99% for the Electric Utility Proxy Group.

VI. COMMON EQUITY COST RATE MODELS

Q. IS IT IMPORTANT THAT COST OF COMMON EQUITY MODELS BE MARKET-BASED?

A. Yes. As discussed previously, regulated public utilities, like the Companies, must compete for equity in capital markets along with all other companies with commensurate risk, including non-utilities. The cost of common equity is thus determined based on equity market expectations for the returns of those companies. If an individual investor is choosing to invest their capital among companies with comparable risk, they will choose the company providing a higher return over a company providing a lower return.

Q. ARE YOUR COST OF COMMON EQUITY MODELS MARKET-BASED?

A. Yes. The DCF model uses market prices in developing the model's dividend yield component. The RPM uses bond ratings and expected bond yields that reflect the market's assessment of bond/credit risk. In addition, betas (β), which reflect the market/systematic risk component of equity risk premium, are derived from regression analyses of market prices. The CAPM is market-based for many of the same reasons that the RPM is market-based (i.e., the use of expected bond yields and betas). Selection criteria for comparable risk non-price regulated companies are based on regression analyses of market prices and reflect the market's assessment of total risk.

Q. WHAT ANALYTICAL APPROACHES DID YOU USE TO DETERMINE THE COMPANIES' ROE?

A. As discussed earlier, I have relied on the DCF model, the RPM, and the CAPM,

which I apply to the Utility Proxy Groups described above. I also applied these same models to a Non-Price Regulated Proxy Group described later in this section.

I rely on these models because reasonable investors use a variety of tools and do not rely exclusively on a single source of information or single model. Moreover, the models on which I rely focus on different aspects of return requirements and provide different insights to investors' views of risk and return. The DCF model, for example, estimates the investor-required return assuming a constant expected dividend yield and growth rate in perpetuity, while risk premium-based methods (i.e., the RPM and CAPM approaches) provide the ability to reflect investors' views of risk, future market returns, and the relationship between interest rates and the cost of common equity. Just as the use of market data for the Utility Proxy Groups adds the reliability necessary to inform expert judgment in arriving at a recommended common equity cost rate, the use of multiple generally accepted common equity cost rate models also adds reliability and accuracy when arriving at a recommended common equity cost rate.

The use of multiple models also makes intuitive sense considering that market prices are set by the buying and selling behavior of multiple investors, whose circumstances, objectives, and constraints vary over time and across market conditions. One cannot assume a single method is the best measure of the factors motivating those decisions for all investors at all times. Giving undue weight to a single method runs the very real risk of ignoring important information provided by other methods.

In other words, no single model is more reliable than all others under all market conditions. Intuition suggests it is more appropriate to use as many methods as one reasonably can and to reflect the many factors motivating investment decisions as best one can. In this instance, intuition, financial theory,[8] and financial practice reach a common conclusion: one should apply and reasonably consider multiple methods when estimating the ROE.

A. Discounted Cash Flow Model

Q. WHAT IS THE THEORETICAL BASIS OF THE DCF MODEL?

A. The theory underlying the DCF model is that the present value of an expected future stream of net cash flows during the investment holding period can be determined by discounting those cash flows at the cost of capital, or the investors' capitalization rate. DCF theory indicates that an investor buys a stock for an expected total return rate, which is derived from the cash flows received from dividends and market price appreciation. Mathematically, the dividend yield on market price plus a growth rate equals the capitalization rate; i.e., the total common equity return rate expected by investors.

Q. WHICH VERSION OF THE DCF MODEL DID YOU USE?

A. I used the single-stage constant growth DCF model.

[8] As Brigham explains: "Whereas debt and preferred stocks are contractual obligations which have easily determined costs, it is not at all easy to estimate [the ROE]. However, three methods can be used: (1) the Capital Asset Pricing Model (CAPM), (2) the discounted cash flow (DCF) model, and (3) the bond-yield-plus-risk-premium approach. These methods should not be regarded as mutually exclusive – no one dominates the others, and all are subject to error when used in practice. Therefore, when faced with the task of estimating a company's cost of equity, we generally use all three methods and then choose among them on the basis of our confidence in the data used for each in the specific case at hand." Eugene F. Brigham, Louis C. Gapenski, Financial Management, Theory and Practice, 7th ed., The Dryden Press, 1994, at 341.

Q. PLEASE DESCRIBE THE DIVIDEND YIELD YOU USED IN APPLYING THE CONSTANT GROWTH DCF MODEL.

A. The unadjusted dividend yields are based on the proxy companies' dividends as of February 28, 2025, divided by the average closing market price for the 60 trading days ended February 28, 2025.[9]

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO THE DIVIDEND YIELD.

A. Because dividends are paid periodically (e.g. quarterly), as opposed to continuously (daily), an adjustment must be made to the dividend yield. This is often referred to as the discrete, or the "Gordon Periodic," version of the DCF model.

DCF theory calls for using the full growth rate, or D_1, in calculating the model's dividend yield component. Because the companies in the Gas and Electric Utility Proxy Groups increase their quarterly dividends at various times during the year, a reasonable assumption is to reflect one-half the annual dividend growth rate in the dividend yield component, or $D_{1/2}$. Because the dividend should be representative of the next 12-month period, this adjustment is a conservative approach that does not overstate the dividend yield. Therefore, the actual average dividend yields in Column 1, page 1 of Schedule DWD-3 have been adjusted upward to reflect one-half the average projected growth rate shown in Column 5.

Q. PLEASE EXPLAIN THE BASIS FOR THE GROWTH RATES YOU APPLIED TO THE UTILITY PROXY GROUPS IN YOUR CONSTANT GROWTH DCF MODEL.

A. Investors with more limited resources than institutional investors are likely to rely

[9] *See*, Column 1, page 1 of Schedule DWD-3.

on widely available financial information services, such as *Value Line*, Zacks, and S&P Capital IQ. Investors realize that analysts have significant insight into the dynamics of the industries and individual companies they analyze, as well as companies' abilities to effectively manage the effects of changing laws and regulations, and ever-changing economic and market conditions. For these reasons, I used analysts' five-year forecasts of EPS growth in my DCF analysis.

Over the long run, there can be no growth in DPS without growth in EPS. Security analysts' earnings expectations have a more significant influence on market prices than dividend expectations. Thus, using earnings growth rates in a DCF analysis provides a better match between investors' market price appreciation expectations and the growth rate component of the DCF.

Q. PLEASE SUMMARIZE THE CONSTANT GROWTH DCF MODEL RESULTS.

A. As shown on page 1 of Schedule DWD-3, for the Gas Utility Proxy Group, the mean result of applying the single-stage DCF model is 10.27%, the median result is 10.31%, and the average of the two is 10.29%. For the Electric Utility Proxy Group, the mean DCF result is 10.33%, the median result is 10.30%, and the average of the two is 10.32%. In arriving at a conclusion for the constant growth DCF-indicated common equity cost rate for the Gas and Electric Utility Proxy Groups, I relied on an average of the mean and the median results of the DCF, or 10.29% (gas) and 10.32% (electric). This approach considers all the proxy utilities' results, while mitigating the high and low outliers of those individual results.

B. The Risk Premium Model

Q. PLEASE DESCRIBE THE THEORETICAL BASIS OF THE RPM.

A. The RPM is based on the fundamental financial principle of risk and return; namely, that investors require greater returns for bearing greater risk. The RPM recognizes that common equity capital has greater investment risk than debt capital, as common equity shareholders are behind debt holders in any claim on a company's assets and earnings. As a result, investors require higher returns from common stocks than from bonds to compensate them for bearing the additional risk.

While it is possible to directly observe bond returns and yields, investors' required common equity returns cannot be directly determined or observed. According to RPM theory, one can estimate a common equity risk premium over bonds (either historically or prospectively) and use that premium to derive a cost rate of common equity. The cost of common equity equals the expected cost rate for long-term debt capital, plus a risk premium over that cost rate, to compensate common shareholders for the added risk of being unsecured and last-in-line for any claim on the corporation's assets and earnings upon liquidation.

Q. PLEASE EXPLAIN THE TOTAL MARKET APPROACH RPM.

A. The total market approach RPM adds a prospective public utility bond yield to an average of: 1) an equity risk premium that is derived from a beta-adjusted total market equity risk premium, 2) an equity risk premium based on the S&P Utilities Index, and 3) an equity risk premium based on authorized ROEs for gas and electric utilities, respectively.

Q. PLEASE EXPLAIN THE BASIS OF THE EXPECTED BOND YIELD OF 5.80% APPLICABLE TO THE GAS UTILITY PROXY GROUP AND THE 5.86% EXPECTED BOND YIELD APPLICABLE TO THE ELECTRIC UTILITY PROXY GROUP.

A. The first step in the total market approach RPM analysis is to determine the expected bond yield. Because both ratemaking and the cost of capital, including common equity cost rate, are prospective in nature, a prospective yield on similarly-rated long-term debt is essential. I relied on a consensus forecast of about 50 economists of the expected yield on Aaa-rated corporate bonds for the six calendar quarters ending with the second quarter of 2026, and *Blue Chip Financial Forecasts'("Blue Chip")* long-term projections for 2026 to 2030, and 2031 to 2035. As shown on line 1, page 1 of Schedule DWD-4, the average expected yield on Moody's Aaa-rated corporate bonds is 5.35%. To derive an expected yield on Moody's A2-rated public utility bonds, I made an upward adjustment of 0.38%, which represents a recent spread between Aaa-rated corporate bonds and A2-rated public utility bonds, in order to adjust the expected Aaa-rated corporate bond yield to an equivalent A2-rated public utility bond yield.[10] Adding that recent 0.38% spread to the expected Aaa-rated corporate bond yield of 5.35% results in an expected A2-rated public utility bond yield of 5.73%.

I then reviewed the average credit rating for the Utility Proxy Groups from Moody's to determine if an adjustment to the estimated A2-rated public utility bond was necessary. Since the Gas Utility Proxy Group's average Moody's long-term

[10] As shown on line 2 and explained in note 2, page 1 of Schedule DWD-4.

issuer rating is A3, and the Electric Utility Proxy Group's average Moody's long-term issuer rating is Baa1, additional adjustments to the expected Moody's A2 public utility bond yields are needed to reflect the difference in bond ratings for each group. Upward adjustments of 0.07% and 0.13%, which are one-third and two-thirds the recent spread between A2 and Baa2 public utility bond yields, respectively, result in 5.80% and 5.86% expected bond yields for the Gas Utility Proxy Group and Electric Utility Proxy Group, respectively.

Table 5: Summary of the Calculation of the Gas and Electric Utility Proxy Groups' Projected Bond Yields[11]

	Gas	**Electric**
Prospective Yield on Moody's Aaa-Rated Corporate Bonds (*Blue Chip)*	5.35%	5.35%
Adjustment to Reflect Yield Spread Between Moody's Aaa-Rated Corporate Bonds and Moody's A2-Rated Utility Bonds	0.38%	0.38%
Adjustment to Reflect the Gas Utility Proxy Group's Average Moody's Bond Rating of A3	0.07%	
Adjustment to Reflect the Electric Utility Proxy Group's Average Moody's Bond Rating of Baa1		0.13%
Prospective Bond Yield Applicable to the Utility Proxy Group	5.80%	5.86%

Q. PLEASE EXPLAIN HOW THE BETA-DERIVED EQUITY RISK PREMIUM IS DETERMINED.

A. The components of the beta-derived risk premium model are: 1) an expected market equity risk premium over corporate bonds, and 2) the beta. The derivation of the beta-derived equity risk premium that I applied to the Gas and Electric Utility Proxy

[11] As shown on page 1 of Schedule DWD-4.

Groups are shown on lines 1 through 8, page 6 of Schedule DWD-4. The total beta-derived equity risk premium I applied is based on an average of three historical market data-based equity risk premiums, a *Value Line*-based equity risk premium, and a combined *Value Line,* Bloomberg, and S&P Capital IQ-based equity risk premium. Each of these is described below.

Q. HOW DID YOU DERIVE A MARKET EQUITY RISK PREMIUM BASED ON LONG-TERM HISTORICAL DATA?

A. To derive a historical market equity risk premium, I used the most recent holding period returns for the large company common stocks less the average historical yield on Moody's Investors Service ("Moody's") Aaa/Aa2-rated corporate bonds for the period 1928 to 2024. Using holding period returns over a very long time is appropriate because it is consistent with the long-term investment horizon presumed by investing in a going concern, i.e., a company expected to operate in perpetuity.

The long-term arithmetic mean monthly total return rate on large company common stocks was 12.05% and the long-term arithmetic mean monthly yield on Moody's Aaa/Aa2-rated corporate bonds was 5.95% from 1928-2024. As shown on line 1, page 6 of Schedule DWD-4, subtracting the mean monthly bond yield from the total return on large company stocks results in a long-term historical equity risk premium of 6.10%.

I used the arithmetic mean monthly total return rates for the large company stocks and yields (income returns) for the Moody's Aaa/Aa-rated corporate bonds, because they are appropriate for the purpose of estimating the cost of capital as

noted in Kroll's Stocks, Bonds, Bills, and Inflation ("SBBI") Yearbook 2023 ("SBBI – 2023").[12] Using the arithmetic mean return rates and yields is appropriate because historical total returns and equity risk premiums provide insight into the variance and standard deviation of returns needed by investors in estimating future risk when making a current investment. If investors relied on the geometric mean of historical equity risk premiums, they would have no insight into the potential variance of future returns, because the geometric mean relates the change over many periods to a constant rate of change, thereby obviating the year-to-year fluctuations, or variance, which is critical to risk analysis.

Q. PLEASE EXPLAIN THE DERIVATION OF THE REGRESSION-BASED MARKET EQUITY RISK PREMIUM.

A. To derive the regression-based market equity risk premium of 6.82% shown on line 2, page 6 of Schedule DWD-4, I used the same monthly annualized total returns on large company common stocks relative to the monthly annualized yields on Moody's Aaa/Aa-rated corporate bonds as mentioned above. I modeled the relationship between interest rates and the market equity risk premium using the observed monthly market equity risk premium as the dependent variable, and the monthly yield on Moody's Aaa/Aa-rated corporate bonds as the independent variable. I then used a linear Ordinary Least Squares ("OLS") regression, in which the market equity risk premium is expressed as a function of the Moody's Aaa/Aa-rated corporate bonds yield:

$$RP = \alpha + \beta\ (R_{Aaa/Aa})$$

[12] *See*, SBBI - 2023, at 194.

Q. PLEASE EXPLAIN THE DERIVATION OF THE PREDICTIVE RISK PREMIUM MODEL ("PRPM") EQUITY RISK PREMIUM.

A. The PRPM, published in the *Journal of Regulatory Economics* and *The Electricity Journal,*[13] was developed from the work of Robert F. Engle, who shared the Nobel Prize in Economics in 2003 "for methods of analyzing economic time series with time-varying volatility ("ARCH")".[14] Engle found that volatility changes over time and is related from one period to the next, especially in financial markets. Engle discovered that the volatility in prices and returns clusters over time, and is therefore highly predictable, and can be used to predict future levels of risk and risk premiums.

The PRPM estimates the risk / return relationship directly, as the predicted equity risk premium is generated by the prediction of volatility or risk. The PRPM is not based on an estimate of investor behavior, but rather on the evaluation of the results of that behavior (i.e., the variance of historical equity risk premiums).

The inputs to the model are the historical returns on large company stocks minus the historical monthly yield on Moody's Aaa/Aa-rated corporate bonds from January 1928 through February 2025. Using a generalized form of ARCH, known as GARCH, I calculated each of the projected equity risk premiums using Eviews© statistical software. When the GARCH model is applied to the historical return

[13] Autoregressive conditional heteroscedasticity. *See*, "A New Approach for Estimating the Equity Risk Premium for Public Utilities", Pauline M. Ahern, Frank J. Hanley and Richard A. Michelfelder, *The Journal of Regulatory Economics* (December 2011), 40:261-278 and "Comparative Evaluation of the Predictive Risk Premium Model, the Discounted Cash Flow Model and the Capital Asset Pricing Model for Estimating the Cost of Common Equity", Richard A. Michelfelder, Pauline M. Ahern, Dylan W. D'Ascendis, and Frank J. Hanley, *The Electricity Journal* (May 2013), 84-89.

[14] www.nobelprize.org.

data, it produces a predicted GARCH variance series and a GARCH coefficient. Multiplying the predicted monthly variance by the GARCH coefficient and then annualizing it, produces the predicted annual equity risk premium. The resulting PRPM predicted a market equity risk premium of 7.32%.[15]

Q. PLEASE EXPLAIN THE DERIVATION OF A PROJECTED EQUITY RISK PREMIUM BASED ON *VALUE LINE* DATA FOR YOUR RPM ANALYSIS.

A. As noted above, because both ratemaking and the cost of capital are prospective, a prospective market equity risk premium is needed. The derivation of the forecasted or prospective market equity risk premium can be found in note 4, page 6 of Schedule DWD-4. Consistent with my calculation of the dividend yield component in my DCF analysis, this prospective market equity risk premium is derived from an average of the three- to five-year median market price appreciation potential by *Value Line* for the 13 weeks ended February 28, 2025, plus an average of the median estimated dividend yield for the common stocks of the 1,700 firms covered in *Value Line*'s Standard Edition.[16]

The average median expected price appreciation is 42%, which translates to a 9.16% annual appreciation, and, when added to the average of *Value Line's* median expected dividend yields of 2.04%, equates to a forecasted annual total return rate on the market of 11.20%. The forecasted Moody's Aaa-rated corporate bond yield of 5.35% is deducted from the total market return of 11.20%, resulting in an equity risk premium of 5.85%, as shown on line 4, page 6 of Schedule DWD-4.

[15] Shown on line 3, page 6 of Schedule DWD-4.
[16] As explained in detail in note 1, page 2 of Schedule DWD-5.

Q. PLEASE EXPLAIN THE DERIVATION OF AN EQUITY RISK PREMIUM BASED ON BLOOMBERG DATA.

A. Using data from *Value Line*, Bloomberg, and S&P Capital IQ, I calculated an expected total return on the S&P 500 companies using expected dividend yields and long-term growth estimates as a proxy for capital appreciation. The expected total return for the S&P 500 is 15.23%. Subtracting the prospective yield on Moody's Aaa-rated corporate bonds of 5.35% results in a 9.88% projected equity risk premium as shown on page 6, line 5 of Schedule DWD-4.

Q. WHAT WAS YOUR CONCLUSION OF A BETA-DERIVED EQUITY RISK PREMIUM FOR USE IN YOUR RPM ANALYSIS?

A. I gave equal weight to all five equity risk premiums based on each source - historical, *Value Line*, and combined *Value Line*, Bloomberg, and S&P Capital IQ - in arriving at a 7.19% equity risk premium.

Table 6: Summary of the Calculation of the Equity Risk Premium Using Total Market Returns[17]

Historical Spread Between Total Returns of Large Stocks and Aaa and Aa2-Rated Corporate Bond Yields (1928 – 2024)	6.10%
Regression Analysis on Historical Data	6.82%
PRPM Analysis on Historical Data	7.32%
Prospective Equity Risk Premium using Total Market Returns from *Value Line* Summary & Index less Projected Aaa Corporate Bond Yields	5.85%
Prospective Equity Risk Premium using Measures of Capital Appreciation and Income Returns for the S&P 500 less Projected Aaa Corporate Bond Yields	9.88%
Average	7.19%

[17] As shown on page 6 of Schedule DWD-4.

After calculating the average market equity risk premium of 7.19%, I adjusted it by beta to account for the risk of the Gas and Electric Utility Proxy Groups. As discussed below, beta is a meaningful measure of prospective relative risk to the market as a whole, and is a logical way to allocate a company's, or proxy group's, share of the market's total equity risk premium relative to corporate bond yields. As shown on page 1 of Schedule DWD-5, the average of the mean and median betas for the Gas and Electric Utility Proxy Groups are 0.79 and 0.73, respectively. Multiplying the average betas for each group by the market equity risk premium of 7.19% results in beta-adjusted equity risk premiums for the Gas and Electric Utility Proxy Groups of 5.68% and 5.25%, respectively.

Q. HOW DID YOU DERIVE THE EQUITY RISK PREMIUM BASED ON THE S&P UTILITY INDEX AND MOODY'S A-RATED PUBLIC UTILITY BONDS?

A. I estimated three equity risk premiums based on S&P Utility Index holding period returns and one equity risk premium based on the expected returns of the S&P Utilities Index, using *Value Line,* Bloomberg, and S&P Capital IQ data. Turning first to the S&P Utility Index holding period returns, I derived a long-term monthly arithmetic mean equity risk premium between the S&P Utility Index total returns of 10.59% and monthly Moody's A2-rated public utility bond yields of 6.42% from 1928 to 2024 to arrive at an equity risk premium of 4.16%.[18] I then used the same historical data to derive an equity risk premium of 4.80% based on a regression of the monthly equity risk premiums. The final S&P Utility Index holding period

[18] As shown on line 1, page 9 of Schedule DWD-4.

equity risk premium involved applying the PRPM using the historical monthly equity risk premiums from January 1928 to February 2025 to arrive at a PRPM-derived equity risk premium of 5.07% for the S&P Utility Index.

I then derived expected total returns on the S&P Utilities Index of 10.73% using data from *Value Line*, Bloomberg, and S&P Capital IQ and subtracted the prospective Moody's A2-rated public utility bond yield of 5.73%,[19] which resulted in an equity risk premium of 5.00%. As with the market equity risk premiums, I averaged the four risk premiums to arrive at my utility-specific equity risk premium of 4.76%.

Table 7: Summary of the Calculation of the Equity Risk Premium Using S&P Utility Index Holding Returns[20]

Historical Spread Between Total Returns of the S&P Utilities Index and A2-Rated Utility Bond Yields (1928 – 2024)	4.16%
Regression Analysis on Historical Data	4.80%
PRPM Analysis on Historical Data	5.07%
Prospective Equity Risk Premium using Measures of Capital Appreciation and Income Returns for the S&P Utilities Index less Projected A2 Utility Bond Yields	5.00%
Average	4.76%

Q. HOW DID YOU DERIVE AN EQUITY RISK PREMIUM OF 4.73% BASED ON AUTHORIZED ROES FOR GAS DISTRIBUTION UTILITIES?

A. The equity risk premium of 4.73% shown on line 3, page 5 of Schedule DWD-4 is the result of a regression analysis based on regulatory awarded gas distribution

[19] Derived on line 3, page 1 of Schedule DWD-4.
[20] As shown on page 9 of Schedule DWD-4.

ROEs related to the yields on Moody's A2-rated public utility bonds. That analysis is shown on page 10 of Schedule DWD-4. Page 10 of Schedule DWD-4 contains the graphical results of a regression analysis of 848 rate cases for gas distribution utilities which were fully litigated during the period from January 1, 1980 through February 28, 2025. It shows the implicit equity risk premium relative to the yields on A2-rated public utility bonds immediately prior to the issuance of each regulatory decision. It is readily discernible that there is an inverse relationship between the yield on A2-rated public utility bonds and equity risk premiums. In other words, as interest rates decline, the equity risk premium rises and vice versa, a result consistent with financial literature on the subject.[21] I used the regression results to estimate the equity risk premium applicable to the projected yield on Moody's A2-rated public utility bonds of 5.73%. Given the expected A2-rated utility bond yield of 5.73%, it can be calculated that the indicated equity risk premium applicable to that bond yield is 4.73%, which is shown on line 3, page 5 of Schedule DWD-4.

Q. HOW DID YOU DERIVE AN EQUITY RISK PREMIUM OF 4.77% BASED ON AUTHORIZED ROES FOR ELECTRIC UTILITIES?

A. The equity risk premium of 4.77% shown on line 4, page 7 of Schedule DWD-4 is the result of a regression analysis based on regulatory awarded electric utility ROEs related to the yields on Moody's A2-rated public utility bonds. That analysis is shown on page 11 of Schedule DWD-4. Page 11 of Schedule DWD-4 contains the

[21] *See, e.g.*, Robert S. Harris and Felicia C. Marston, *The Market Risk Premium: Expectational Estimates Using Analysts' Forecasts*, Journal of Applied Finance, Vol. 11, No. 1, 2001, at 11-12; Eugene F. Brigham, Dilip K. Shome, and Steve R. Vinson, *The Risk Premium Approach to Measuring a Utility's Cost of Equity*, Financial Management, Spring 1985, at pp. 33-45.

graphical results of a regression analysis of 1,257 rate cases for electric utilities which were fully litigated during the period from January 1, 1980 through February 28, 2025. It shows the implicit equity risk premium relative to the yields on A2-rated public utility bonds immediately prior to the issuance of each regulatory decision. Similar to the analysis using gas distribution utilities, it is readily discernible that there is also an inverse relationship between the yield on A2-rated public utility bonds and equity risk premiums for electric utilities. I therefore used the regression results to estimate the equity risk premium applicable to the projected yield on Moody's A2-rated public utility bonds of 5.73%. Given the expected A2-rated utility bond yield of 5.73%, it can be calculated that the indicated equity risk premium applicable to that bond yield is 4.77%, which is shown on line 4, page 5 of Schedule DWD-4.

Q. WHAT IS YOUR CONCLUSION OF AN EQUITY RISK PREMIUM FOR USE IN YOUR TOTAL MARKET APPROACH RPM ANALYSIS?

A. The equity risk premiums I applied to the Gas and Electric Utility Proxy Groups were 5.06% and 4.93%, respectively, which gave equal weight to the beta-adjusted equity risk premium for the Gas and Electric Utility Proxy Groups, the S&P Utilities Index, and the authorized return utility equity risk premiums as shown on page 5 of Schedule DWD-4.

Table 8: Summary of Conclusions for the Equity Risk Premium for Use in the Total Market Approach for the Utility Proxy Groups[22]

	Gas Proxy Group	Electric Proxy Group
Beta-Adjusted Equity Risk Premium	5.68%	5.25%
S&P Utilities Index Equity Risk Premium	4.76%	4.76%
Authorized ROE Equity Risk Premium	4.73%	4.77%
Average	5.06%	4.93%

Q. WHAT IS THE INDICATED RPM COMMON EQUITY COST RATE BASED ON THE TOTAL MARKET APPROACH?

A. As shown on line 7, page 1 of Schedule DWD-4, I calculated common equity cost rates of 10.86% and 10.79% for the Gas and Electric Utility Proxy Groups, respectively, based on the total market approach RPM.

Table 9: Summary of the Total Market Return Risk Premium Model[23]

	Gas Proxy Group	Electric Proxy Group
Prospective Moody's Utility Bond Yield Applicable to the Utility Proxy Group	5.80%	5.86%
Prospective Equity Risk Premium	5.06%	4.93%
Indicated Cost of Common Equity	10.86%	10.79%

C. The Capital Asset Pricing Model

Q. PLEASE EXPLAIN THE THEORETICAL BASIS OF THE CAPM.

A. CAPM theory defines risk as the co-variability of a security's returns with the market's returns as measured by the beta (β). A beta less than 1.0 indicates lower

[22] As shown on page 5 of Schedule DWD-4.
[23] As shown on page 1 of Schedule DWD-4.

variability than the market as a whole, while a beta greater than 1.0 indicates greater variability than the market.

The CAPM assumes that all non-market or unsystematic risk can be eliminated through diversification. The risk that cannot be eliminated through diversification is called market, or systematic, risk. In addition, the CAPM presumes that investors only require compensation for systematic risk, which is the result of macroeconomic and other events that affect the returns on all assets. The model is applied by adding a risk-free rate of return to a market risk premium, which is adjusted proportionately to reflect the systematic risk of the individual security relative to the total market as measured by beta. The traditional CAPM model is expressed as:

$$R_s = R_f + \beta (R_m - R_f)$$

Where:
- R_s = Return rate on the common stock
- R_f = Risk-free rate of return
- R_m = Return rate on the market as a whole
- β = Adjusted beta (volatility of the security relative to the market as a whole)

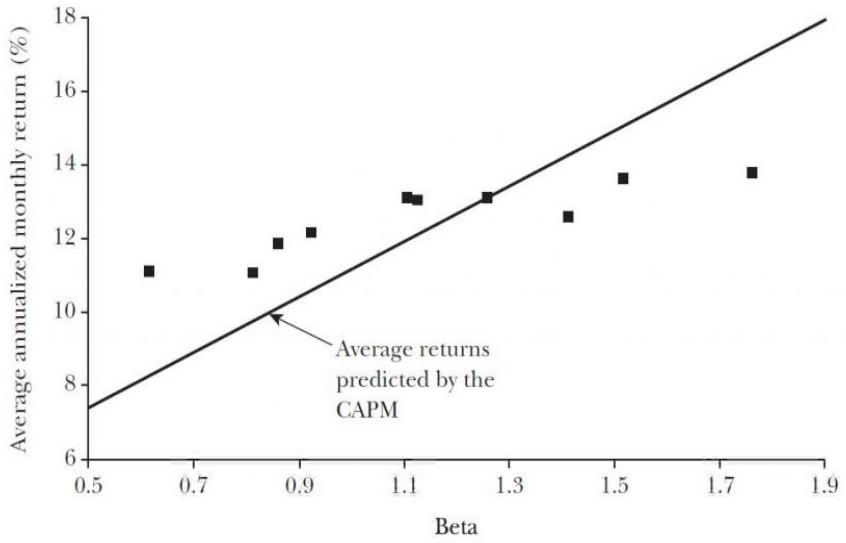
Numerous tests of the CAPM have measured the extent to which security returns and beta are related as predicted by the CAPM, confirming its validity. The empirical CAPM ("ECAPM") reflects the reality that while the results of these tests support the notion that the beta is related to security returns, the empirical Security

Market Line ("SML") described by the CAPM formula is not as steeply sloped as the predicted SML.[24]

The ECAPM reflects this empirical reality. Fama and French clearly state regarding their Figure 2, below, that "[t]he returns on the low beta portfolios are too high, and the returns on the high beta portfolios are too low."[25]

Figure 2 http://pubs.aeaweb.org/doi/pdfplus/10.1257/0895330042162430

Average Annualized Monthly Return versus Beta for Value Weight Portfolios Formed on Prior Beta, 1928–2003



Morin also states that:

> With few exceptions, the empirical studies agree that … low-beta securities earn returns somewhat higher than the CAPM would predict, and high-beta securities earn less than predicted.[26]

* * *

[24] Roger A. Morin, Modern Regulatory Finance (Public Utility Reports, Inc., 2021), at 223. ("Morin")

[25] Eugene F. Fama and Kenneth R. French, *The Capital Asset Pricing Model: Theory and Evidence*, Journal of Economic Perspectives, Vol. 18, No. 3, Summer 2004 at p. 33 ("Fama & French").

[26] Morin, at 207.

Therefore, the empirical evidence suggests that the expected return on a security is related to its risk by the following approximation:

$$K = R_F + x (R_M - R_F) + (1-x) \beta(R_M - R_F)$$

where x is a fraction to be determined empirically. The value of x that best explains the observed relationship [is] Return = 0.0829 + 0.0520 β is between 0.25 and 0.30. If x = 0.25, the equation becomes:

$$K = R_F + 0.25(R_M - R_F) + 0.75 \beta(R_M - R_F)$$[27]

Fama and French provide similar support for the ECAPM when they state:

> The early tests firmly reject the Sharpe-Lintner version of the CAPM. There is a positive relation between beta and average return, but it is too "flat."… The regressions consistently find that the intercept is greater than the average risk-free rate… and the coefficient on beta is less than the average excess market return… This is true in the early tests… as well as in more recent cross-section regressions tests, like Fama and French (1992).[28]

Finally, Fama and French further note:

> Confirming earlier evidence, the relation between beta and average return for the ten portfolios is much flatter than the Sharpe-Linter CAPM predicts. The returns on low beta portfolios are too high, and the returns on the high beta portfolios are too low. For example, the predicted return on the portfolio with the lowest beta is 8.3 percent per year; the actual return as 11.1 percent. The predicted return on the portfolio with the t beta is 16.8 percent per year; the actual is 13.7 percent.[29]

Clearly, the justification from Morin, and Fama and French, along with their reviews of other academic research on the CAPM, validate the use of the ECAPM. In view of theory and practical research, I have applied both the traditional CAPM and the ECAPM to the companies in the Gas and Electric Utility Proxy Groups and averaged the results.

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[27] Morin, at 221.
[28] Fama & French, at 32.
[29] Fama & French, at 33.

Q. WHAT BETA DID YOU USE IN YOUR CAPM ANALYSIS?

A. For the beta in my CAPM analysis, I considered two sources: *Value Line* and Bloomberg. While both of those services adjust their calculated (or "raw") betas to reflect the tendency of beta to regress to the market mean of 1.00, *Value Line* calculates beta over a five-year period, while Bloomberg calculates it over a two-year period.

Q. PLEASE DESCRIBE YOUR SELECTION OF A RISK-FREE RATE OF RETURN.

A. As shown in Column 5, page 1 of Schedule DWD-5, the risk-free rate adopted for applications of the CAPM is 4.55%. This risk-free rate is based on the average of the *Blue Chip* consensus forecast of the expected yields on 30-year U.S. Treasury bonds for the six quarters ending with the second calendar quarter of 2026, and long-term projections for the years 2026 to 2030 and 2031 to 2035.

Q. WHY DO YOU USE THE PROJECTED 30-YEAR TREASURY YIELD IN YOUR ANALYSES?

A. The yield on long-term U.S. Treasury bonds is almost risk-free and its term is consistent with the long-term cost of capital to public utilities measured by the yields on Moody's A2-rated public utility bonds; the long-term investment horizon inherent in utilities' common stocks; and the long-term life of the jurisdictional rate base to which the allowed fair rate of return (i.e., cost of capital) will be applied. In contrast, short-term U.S. Treasury yields are more volatile and largely a function of Federal Reserve monetary policy.

Q. PLEASE EXPLAIN THE ESTIMATION OF THE EXPECTED RISK PREMIUM FOR THE MARKET RISK PREMIUM USED IN YOUR CAPM ANALYSES.

A. The basis of the market risk premium is explained in detail in note 1 on Schedule DWD-5. As discussed above, the market risk premium is derived from an average of three historical data-based market risk premiums, one *Value Line* data-based market risk premiums, and one *Value Line*, Bloomberg, and S&P Capital IQ data-based market risk premium.

The long-term income return on U.S. Government securities of 4.99% was deducted from the monthly historical total market return of 12.29%, which results in a historical market equity risk premium of 7.31%. A linear OLS regression was applied to the monthly annualized historical returns on the S&P 500 relative to historical yields on long-term U.S. Government securities, which yielded a market equity risk premium of 7.94%. The PRPM market equity risk premium is 8.18% and is derived using the PRPM relative to the yields on long-term U.S. Treasury securities from January 1926 through February 2025.

The *Value Line*-derived forecasted total market equity risk premium is derived by deducting the forecasted risk-free rate of 4.55%, discussed above, from the *Value Line* projected total annual market return of 11.20%, resulting in a forecasted total market equity risk premium of 6.65%.

The S&P 500 projected market equity risk premium using *Value Line,* Bloomberg and S&P Capital IQ data is derived by subtracting the projected risk-

free rate of 4.55% from the projected total return of the S&P 500 of 15.23%. The resulting market equity risk premium is 10.68%.

These five measures, when averaged, result in an average total market equity risk premium of 8.15%

Table 10: Summary of the Calculation of the Market Risk Premium for Use in the CAPM[30]

Historical Spread Between Total Returns of Large Stocks and Long-Term Government Bond Yields (1926 – 2024)	7.31%
Regression Analysis on Historical Data	7.94%
PRPM Analysis on Historical Data	8.18%
Prospective Equity Risk Premium using Total Market Returns from *Value Line* Summary & Index less Projected 30-Year Treasury Bond Yields	6.65%
Prospective Equity Risk Premium using Measures of Capital Appreciation and Income Returns for the S&P 500 less Projected 30-Year Treasury Bond Yields	10.68%
Average	8.15%

Q. WHAT ARE THE RESULTS OF YOUR APPLICATION OF THE TRADITIONAL AND EMPIRICAL CAPM TO THE GAS AND ELECTRIC UTILITY PROXY GROUPS?

A. As shown on page 1 of Schedule DWD-5, the mean result of my CAPM/ECAPM analyses for the Gas Utility Proxy Group is 11.10%, the median is 11.13%, and the average of the two is 11.12%. For the Electric Utility Proxy Group, the mean CAPM/ECAPM result is 10.79%, the median is 10.70%, and the average of the two is 10.75%. Consistent with my reliance on the average of mean and median DCF

[30] As shown on page 2 of Schedule DWD-5.

results discussed above, the indicated common equity cost rates for the Gas and Electric Utility Proxy Group using the CAPM/ECAPM are 11.12% and 10.75%, respectively.

D. Common Equity Cost Rates for Proxy Group of Domestic, Non-Price Regulated Companies Based on the DCF, RPM, and CAPM

Q. WHY DID YOU ALSO CONSIDER PROXY GROUPS OF DOMESTIC, NON-PRICE REGULATED COMPANIES?

A. In the *Hope* and *Bluefield* cases, the U.S. Supreme Court did not specify that comparable risk companies had to be utilities. Because the purpose of rate regulation is to be a substitute for marketplace competition, non-price regulated firms operating in the competitive marketplace make an excellent proxy if they are comparable in total risk to the Gas and Electric Utility Proxy Groups being used to estimate the cost of common equity. The selection of such domestic, non-price regulated competitive firms theoretically and empirically results in a proxy group that is comparable in total risk to the Gas and Electric Utility Proxy Groups, because all of these companies compete for capital in the exact same markets.

Q. HOW DID YOU SELECT NON-PRICE REGULATED COMPANIES THAT ARE COMPARABLE IN TOTAL RISK TO THE REGULATED GAS AND ELECTRIC UTILITY PROXY GROUPS?

A. In order to select proxy groups of domestic, non-price regulated companies similar in total risk to the Gas and Electric Utility Proxy Groups, I relied on beta and related statistics derived from *Value Line* regression analyses of weekly market prices over the most recent 260 weeks (i.e., five years) for each group. These selection criteria resulted in a proxy group of 49 domestic, non-price regulated firms comparable in

total risk to the Gas Utility Proxy Group and 47 non-price regulated firms comparable in total risk to the Electric Utility Proxy Group. Total risk is the sum of non-diversifiable market risk and diversifiable company-specific risk. The criteria used in selecting the domestic, non-price regulated firms were:

(i) They must be covered by *Value Line* (Standard Edition);

(ii) They must be domestic, non-price regulated companies, i.e., not utilities;

(iii) Their betas must lie within plus or minus two standard deviations of the average unadjusted betas of the Gas and Electric Utility Proxy Groups, respectively; and

(iv) The residual standard errors of the *Value Line* regressions which gave rise to the unadjusted betas must lie within plus or minus two standard deviations of the average residual standard errors of the Gas and Electric Utility Proxy Groups, respectively.

Betas measure market, or systematic, risk, which is not diversifiable. The residual standard errors of the regressions measure each firm's company-specific, diversifiable risk. Companies that have similar betas and similar residual standard errors resulting from the same regression analyses have similar total investment risk.

Q. HAVE YOU PREPARED A SCHEDULE WHICH SHOWS THE DATA FROM WHICH YOU SELECTED THE DOMESTIC, NON-PRICE REGULATED COMPANIES THAT ARE COMPARABLE IN TOTAL RISK TO THE GAS AND ELECTRIC UTILITY PROXY GROUPS?

A. Yes, the basis of my selection and both proxy groups' regression statistics are shown in Schedule DWD-6.

Q. DID YOU CALCULATE COMMON EQUITY COST RATES USING THE DCF MODEL, RPM, AND CAPM FOR THE NON-PRICE REGULATED PROXY GROUPS?

A. Yes. Because the DCF model, RPM, and CAPM have been applied in an identical manner as described above, I will not repeat the details of the rationale and application of each model. One exception is in the application of the RPM, where I did not use public utility-specific equity risk premiums.

Pages 2 and 3 of Schedule DWD-7 derives the constant growth DCF model common equity cost rate. As shown, the indicated common equity cost rate, using the constant growth DCF for the Non-Price Regulated Proxy Groups comparable in total risk to the Gas and Electric Utility Proxy Groups, are 11.87% and 11.17%, respectively.

Pages 4 through 7 of Schedule DWD-7 contain the data and calculations that support the 12.27% and 12.29% RPM common equity cost rates applicable to the Non-Price Regulated Proxy Groups comparable in total risk to the Gas and Electric Utility Proxy Groups, respectively. As shown on line 1, page 4 of Schedule DWD-7, the consensus prospective yield on Moody's Baa2-rated corporate bonds

for the six quarters ending in the second quarter of 2026, and for the years 2026 to 2030 and 2031 to 2035, is 6.14%.[31] Since the Non-Price Regulated Proxy Group relative to the Gas Utility Proxy Group has an average Moody's long-term issuer rating of A3/Baa1, a downward adjustment of 0.14% to the projected Baa2-rated corporate bond yield is necessary to reflect the difference in ratings.[32] Similarly, as the Non-Price Regulated Proxy Group relative to the Electric Utility Proxy Group has an average Moody's long-term issuer rating of A3, a downward adjustment of 0.18% to the projected Baa2-rated corporate bond yield is necessary to reflect the difference in ratings.[33]

This results in a projected A3/Baa1-rated corporate bond yield of 6.01% applicable to the Non-Price Regulated Proxy Group comparable in total risk to the Gas Utility Proxy Group, and a projected A3-rated corporate bond yield of 5.96% applicable to the Non-Price Regulated Proxy Group comparable in total risk to the Electric Utility Proxy Group

When the beta-adjusted risk premiums of 6.26% and 6.33%[34] relative to the Non-Price Regulated Proxy Groups comparable in total risk to the Gas and Electric Utility Proxy Groups, respectively, are added to the prospective A3/Baa1-rated and A3-rated corporate bond yields of 6.01% and 5.96%, the indicated RPM common equity cost rates are 12.27% and 12.29%, respectively.

Pages 8 and 9 of Schedule DWD-7 contain the inputs and calculations that support my indicated CAPM/ECAPM common equity cost rates of 11.75% and

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31 *Blue Chip Financial Forecasts*, February 28, 2025, at 2 and November 27, 2024 at 14.
32 As demonstrated in line 2 and described in note 2, page 4 of Schedule DWD-7.
33 As demonstrated in line 2 and described in note 2, page 4 of Schedule DWD-7.
34 Derived on page 7 of Schedule DWD-7.

11.89% for the Non-Price Regulated Proxy Groups comparable in total risk to the Gas and Electric Utility Proxy Groups, respectively.

Q. WHAT IS THE COST RATE OF COMMON EQUITY BASED ON THE NON-PRICE REGULATED PROXY GROUPS COMPARABLE IN TOTAL RISK TO THE GAS AND ELECTRIC UTILITY PROXY GROUPS?

A. As shown on page 1 of Schedule DWD-7, the results of the common equity models applied to the Non-Price Regulated Proxy Groups that are comparable in total risk to the Gas and Electric Utility Proxy Groups are as follows:

Table 11: Summary of Common Equity Cost Rates for the Non-Price Regulated Proxy Groups

	Non-Utility Group Based on Gas Utility Group	Non-Utility Group Based on Electric Utility Group
Discounted Cash Flow Model	11.87%	11.17%
Risk Premium Model	12.27%	12.29%
Capital Asset Pricing Model	11.75%	11.89%
Mean	11.96%	11.78%
Median	11.87%	11.89%
Average of Mean and Median	11.92%	11.84%

The average of the mean and median of these models for the Non-Price Regulated Proxy Groups comparable in total risk to the Gas and Electric Utility Proxy Groups are 11.92% and 11.84%, respectively, which I used as the indicated common equity cost rates for the Non-Price Regulated Proxy Groups.

VII. CONCLUSION OF COMMON EQUITY COST RATES BEFORE ADJUSTMENTS

Q. WHAT ARE THE INDICATED COMMON EQUITY COST RATES FOR THE GAS AND ELECTRIC UTILITY PROXY GROUPS BEFORE ADJUSTMENTS?

A. By applying multiple cost of common equity models to the Gas and Electric Utility Proxy Groups and the Non-Price Regulated Proxy Group, the indicated cost of common equity before any relative risk adjustments is 10.29% - 11.92% for the Gas Utility Proxy Group and 10.32% - 11.84% for the Electric Utility Proxy Group. I used multiple cost of common equity models as primary tools in arriving at my recommended range of common equity cost rates, because no single model is so inherently precise that it can be relied on to the exclusion of other theoretically sound models. Using multiple models adds reliability to the estimated common equity cost rate, with the prudence of using multiple cost of common equity models supported in both the financial literature and regulatory precedent.

As will be discussed below, the Companies have greater risk than their respective Utility Proxy Groups. Because of this, the indicated range of model results based on the Utility Proxy Groups must be adjusted to reflect the Companies' greater relative risk.

VIII. ADJUSTMENTS TO THE COMMON EQUITY COST RATES

A. Size Adjustment

Q. DOES THE COMPANIES' SMALLER SIZE RELATIVE TO THE GAS AND ELECTRIC UTILITY PROXY GROUPS INCREASE THEIR BUSINESS RISK?

A. Yes. The Companies' smaller size relative to the Gas and Electric Utility Proxy Groups indicates greater relative business risk for the Companies because, all else being equal, size has a material bearing on risk.

Size affects business risk because smaller companies generally are less able to cope with significant events that affect sales, revenues and earnings. For example, smaller companies face more risk exposure to business cycles and economic conditions, both nationally and locally. Additionally, the loss of revenues from a few larger customers would have a greater effect on a small company than on a bigger company with a larger, more diverse, customer base.

As further evidence that smaller firms are riskier, investors generally demand greater returns from smaller firms to compensate for less marketability and liquidity of their securities. Kroll's Cost of Capital Navigator: U.S. Cost of Capital Module ("Kroll") discusses the nature of the small-size phenomenon, providing an indication of the magnitude of the size premium based on several measures of size. In discussing "Size as a Predictor of Equity Premiums," Kroll states:

> The size effect is based on the empirical observation that companies of smaller size are associated with greater risk and, therefore, have greater cost of capital [sic]. The "size" of a company is one of the most important risk elements to consider when developing cost of equity capital estimates for use in valuing a business simply because size has been shown to be a *predictor* of equity returns. In other

> words, there is a significant (negative) relationship between size and historical equity returns - as size *decreases*, returns tend to *increase*, and vice versa. (footnote omitted) (emphasis in original)[35]

Furthermore, in "The Capital Asset Pricing Model: Theory and Evidence," Fama and French note size is indeed a risk factor which must be reflected when estimating the cost of common equity. On page 38, they note:

> . . . the higher average returns on small stocks and high book-to-market stocks reflect unidentified state variables that produce undiversifiable risks (covariances) in returns not captured in the market return and are priced separately from market betas.[36]

Based on this evidence, Fama and French proposed their three-factor model which includes a size variable in recognition of the effect size has on the cost of common equity.

Also, it is a basic financial principle that the use of funds invested, and not the source of funds, is what gives rise to the risk of any investment.[37] Eugene Brigham, a well-known authority, states:

> A number of researchers have observed that portfolios of small-firms (sic) have earned consistently higher average returns than those of large-firm stocks; this is called the "small-firm effect." On the surface, it would seem to be advantageous to the small firms to provide average returns in a stock market that are higher than those of larger firms. In reality, it is bad news for the small firm; **what the small-firm effect means is that the capital market demands higher returns on stocks of small firms than on otherwise similar stocks of the large firms**. (emphasis added)[38]

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35 Kroll, Cost of Capital Navigator: U.S. Cost of Capital Module, Size as a Predictor of Equity Returns, at 1.

36 Fama & French, at 25-43.

37 Richard A. Brealey and Stewart C. Myers, Principles of Corporate Finance (McGraw-Hill Book Company, 1996), at 204-205, 229.

38 Eugene F. Brigham, Fundamentals of Financial Management, Fifth Edition (The Dryden Press, 1989), at 623.

Consistent with the financial principle of risk and return discussed above, increased relative risk due to small size must be considered in the allowed rate of return on common equity. Therefore, the Commission's authorization of a cost rate of common equity in this proceeding must appropriately reflect the Companies' unique risks, including their small size, which is justified and supported above by evidence in the financial literature.

Q. IS THERE A WAY TO QUANTIFY A RELATIVE RISK ADJUSTMENT DUE TO THE COMPANIES' SMALL SIZE RELATIVE TO THE GAS AND ELECTRIC UTILITY PROXY GROUPS?

A. Yes. The Companies have greater relative risk than the average utility in the Gas and Electric Utility Proxy Groups because of their smaller size compared with the utilities in those groups, as measured by an estimated market capitalization of common equity for the jurisdictional operations of each company.

Table 12: Size as Measured by Market Capitalization for Valley, Citizens', and Wellsboro, and the Gas and Electric Utility Proxy Groups

	Market Cap (in Millions)*	Times Greater than The Company
Valley Energy, Inc.	$18.603	
Gas Utility Proxy Group	$4,721.136	253.8x
Citizens' Electric Company	$18.097	
Electric Utility Proxy Group	$16,525.930	913.2x
Wellsboro Electric Company	$24.787	
Electric Utility Proxy Group	$16,525.930	666.7x

*From page 1 of Schedule DWD-8.

Valley's, Citizens', and Wellsboro's estimated market capitalizations were $18.603 million, $18.097 million, and $24.787 million respectively, as of February 28, 2025, compared with the market capitalization of the average company in the Gas and Electric Utility Proxy Groups of $4.721 billion and $16.526 billion, respectively, as of February 28, 2025. The average companies in the Gas and Electric Utility Proxy Groups have a market capitalization 253.8 times, 913.2 times and 666.7 times Valley, Citizens', and Wellsboro, respectively.

As a result, it is necessary to adjust the indicated common equity cost rates attributable to the Gas and Electric Utility Proxy Groups upward to reflect the Companies' greater risk due to their smaller relative size. The determination is based on the size premiums for portfolios of New York Stock Exchange, American Stock Exchange, and NASDAQ listed companies ranked by deciles for the 1926 to 2024 period. The average size premium for the Gas and Electric Utility Proxy Groups with market capitalizations of $4.721 and $16.526 billion fall in the 5th and 3rd deciles, respectively, while Valley's, Citizens', and Wellsboro's estimated market capitalizations of $18.603 million, $18.097 million, and $24.787 million respectively, place them in the 10th decile. The size premium spread between the 5th decile and the 10th decile is 3.73%, while the size premium between the 3rd decile and the 10th decile is 3.98%.

Q. HAS THIS COMMISSION CONSIDERED SIZE IN DETERMINING THE AUTHORIZED ROE?

A. Yes, it has. In Docket No. R-2019-3008212, the Commission stated:

> Based on the evidence of record, we agree with the recommendation of the ALJs that the Company be awarded a DCF cost of common

> equity which is one standard deviation about the average of the mean and median proxy group ROE from the Company's DCF analysis. In so doing, we recognize that the Company's size is a factor in assessing its ability to attract capital. Accordingly, we shall reject Citizens' Exception No. 10, I&E's Exception No. 4, and the OCA's Exception No. 7, consistent with the following discussion.
>
> We are not convinced by the arguments of I&E and the OCA that the ALJs erred in awarding a size adjustment to Citizens'. Rather, we are of the same position as the ALJs that the Company's witness Mr. D'Ascendis offered persuasive record evidence that there is a general inverse relationship between size and risk, such that smaller utilities like Citizens' face greater risk.[39]

Q. WHAT WOULD BE THE ROE RESULT USING THE COMMISSION'S METHOD IN THIS CASE?

A. The average of the mean and median DCF model results are 10.29% and 10.32% for the Gas and Electric Utility Proxy Groups, respectively, as shown on page 1 of Schedule DWD-3. The standard deviation of those results is 1.53% and 0.85%, respectively. In view of the indicated size premiums of 3.73% and 3.98% and DCF model size premiums of 1.53% and 0.85%, I recommend size premiums of 1.00% for Valley and 0.85% for Citizens' and Wellsboro.

B. <u>Performance Factor Adjustment</u>

Q. HAVE YOU REFLECTED THE COMPANIES' REQUESTED RATE OF RETURN PREMIUM BASED ON CODE 66 Pa.C.S. § 523 REGARDING PERFORMANCE FACTOR?

A. Yes. The adjustment is shown on line 7 of page 2 of Schedule DWD-1. The testimonies for including the performance factor adjustment in the ROE for the Companies are sponsored by Valley's Witness Mr. Rogers, Citizens' Witness Mr.

[39] Pennsylvania Public Utility Commission, Docket No. R-2019-3008212, Opinion and Order, at 103.

Johnson, and Wellsboro's Witness Mr. Farnsworth. The rate of return premium associated with the performance factor is 0.05%.

Q. HAS THE COMMISSION AWARDED THE COMPANIES A PERFORMANCE FACTOR ADJUSTMENT?

A. Yes, it has. In Docket Nos. R-2019-3008209 (Valley) and R-2019-3008212 (Citizens'), the Commission awarded the Companies performance factor adjustments of 0.05%.[40] As discussed by Valley's Witness Mr. Rogers, Citizens' Witness Mr. Johnson, and Wellsboro's Witness Mr. Farnsworth, it is their belief that the performance factor adjustment still applies.

Q. WHAT IS THE INDICATED COST OF COMMON EQUITY AFTER YOUR COMPANY-SPECIFIC ADJUSTMENTS?

A. Applying the 1.00% and 0.85% size adjustments, and the 0.05% performance factor adjustment to the indicated costs of common equity of 10.29% - 11.92% and 10.32% - 11.84%, applicable to the Gas and Electric Utility Proxy Groups, respectively, results in a range of common equity cost rates of 11.34% - 12.97% for Valley, and 11.22% - 12.74% for Citizens' and Wellsboro.

IX. CONCLUSION

Q. WHAT ARE YOUR RECOMMENDED ROES FOR THE COMPANIES?

A. Given the adjusted ranges of ROEs from 10.29% to 11.92% for the Gas Utility Proxy Group and 11.22% to 12.74% for the Electric Proxy Group, I recommend a

[40] Docket No. R-2019-3008209 (Valley), at 118-120, and Docket No. R-2019-3008212 (Citizens'), at 108-110. Wellsboro did not file a rate case in 2019.

cost of common equity rate of 11.65% for the Companies, which is reasonable and conservative.

Q. IN YOUR OPINION, ARE YOUR PROPOSED ROES FAIR AND REASONABLE TO THE COMPANIES AND THEIR CUSTOMERS?

A. Yes, they are.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

Appendix A:

Dylan W. D'Ascendis, CRRA, CVA
Partner

Summary

Dylan is an experienced consultant and a Certified Rate of Return Analyst (CRRA) and Certified Valuation Analyst (CVA). Dylan joined ScottMadden in 2016 and is a leading expert witness with respect to cost of capital, capital structure, and valuation. He has served as a consultant for investor-owned and municipal utilities and authorities for 17 years. Dylan has testified as an expert witness on over 150 occasions regarding rate of return, cost of service, rate design, and valuation before more than 40 regulatory jurisdictions in the United States and Canada, an American Arbitration Association panel, and the Superior Court of Rhode Island. He also maintains the benchmark index against which the Hennessy Gas Utility Mutual Fund performance is measured. Dylan holds a B.A. in economic history from the University of Pennsylvania and an M.B.A. with concentrations in finance and international business from Rutgers University.

Areas of Specialization

- Expert Witness Testimony
- Rates and Regulation
- Return on Equity
- Valuation
- Utility Regulations
- Rate Case Planning, Management, and Support
- Utility Benchmarking

Recent Articles and Speeches

- "Decoupling, Risk Impacts, and the Cost of Capital." Co-authored with Richard A. Michelfelder, Ph.D., Rutgers University and Pauline M. Ahern. The Electricity Journal. March 2020
- "Decoupling Impact and Public Utility Conservation Investment." Co-authored with Richard A. Michelfelder, Ph.D., Rutgers University and Pauline M. Ahern. Energy Policy Journal. 130 (2019), 311-319
- "Establishing Alternative Proxy Groups." Presentation before the Society of Utility and Regulatory Financial Analysts: 51st Financial Forum. April 4, 2019. New Orleans, LA
- "Past Is Prologue: Future Test Year." Presentation before the National Association of Water Companies 2017 Southeast Water Infrastructure Summit. May 2, 2017. Savannah, GA
- "Comparative Evaluation of the Predictive Risk Premium Model™, the Discounted Cash Flow Model and the Capital Asset Pricing Model." Co-authored with Richard A. Michelfelder, Ph.D., Rutgers University, Pauline M. Ahern, and Frank J. Hanley. The Electricity Journal. May 2013
- "Decoupling: Impact on the Risk and Cost of Common Equity of Public Utility Stocks." Presentation before the Society of Utility and Regulatory Financial Analysts: 45th Financial Forum. April 17-18, 2013. Indianapolis, IN

Recent Assignments

- Provided expert testimony on the cost of capital for ratemaking purposes before numerous state utility regulatory agencies
- Maintains the benchmark index against which the Hennessy Gas Utility Mutual Fund performance is measured
- Sponsored valuation testimony for a large municipal water company in front of an American Arbitration Association Board to justify the reasonability of their lease payments to the city
- Co-authored a valuation report on behalf of a large investor-owned utility in response to a new state regulation which allowed the appraised value of acquired assets into rate base

Sponsor	Date	Case/Applicant	Docket No.	Subject
Regulatory Commission of Alaska				
Goat Lake Hydro, Inc.	12/24	Goat Lake Hydro, Inc.	Docket No. TA7-521	Rate of Return
Alaska Power Company	08/23	Alaska Power Company	Docket No. TA 909-2 / U-23-054	Capital Structure
ENSTAR Natural Gas Company	08/22	ENSTAR Natural Gas Company	Docket No. TA334-4	Rate of Return
Cook Inlet Natural Gas Storage Alaska, LLC	07/21	Cook Inlet Natural Gas Storage Alaska, LLC	Docket No. TA45-733	Capital Structure
Alaska Power Company	09/20	Alaska Power Company; Goat Lake Hydro, Inc.; BBL Hydro, Inc.	Tariff Nos. TA886-2; TA6-521; TA4-573	Capital Structure
Alaska Power Company	07/16	Alaska Power Company	Docket No. TA857-2	Rate of Return
Alberta Utilities Commission				
AltaLink, L.P., and EPCOR Distribution & Transmission, Inc.	02/23	AltaLink, L.P., and EPCOR Distribution & Transmission, Inc.	Proceeding ID. 27084	Determination of Cost-of-Capital Parameters
AltaLink, L.P., and EPCOR Distribution & Transmission, Inc.	01/20	AltaLink, L.P., and EPCOR Distribution & Transmission, Inc.	2021 Generic Cost of Capital, Proceeding ID. 24110	Rate of Return
Arizona Corporation Commission				
EPCOR Water Arizona, Inc.	06/24	EPCOR Water Arizona, Inc.	Docket No. WS-01303A-24-0130	Rate of Return
Arizona Water Company	05/24	Arizona Water Company – Northern Group	Docket No. W-01445A-24-0117	Rate of Return
Foothills Water & Sewer, LLC	10/23	Foothills Water & Sewer, LLC	Docket No. WS-21182A-23-0292	Rate of Return and Fair Value Rate Base
Arizona Water Company	12/22	Arizona Water Company – Eastern Group	Docket No. W-01445A-22-0286	Rate of Return
EPCOR Water Arizona, Inc.	08/22	EPCOR Water Arizona, Inc.	Docket No. WS-01303A-22-0236	Rate of Return
EPCOR Water Arizona, Inc.	06/20	EPCOR Water Arizona, Inc.	Docket No. WS-01303A-20-0177	Rate of Return
Arizona Water Company	12/19	Arizona Water Company – Western Group	Docket No. W-01445A-19-0278	Rate of Return
Arizona Water Company	08/18	Arizona Water Company – Northern Group	Docket No. W-01445A-18-0164	Rate of Return
Arkansas Public Service Commission				
Summit Utilities Arkansas, Inc.	01/24	Summit Utilities Arkansas, Inc.	Docket No. 23-079-U	Rate of Return
Southwestern Electric Power Co.	07/21	Southwestern Electric Power Co.	Docket No. 21-070-U	Return on Equity
CenterPoint Energy Resources Corp.	05/21	CenterPoint Arkansas Gas	Docket No. 21-004-U	Return on Equity
California Public Utilities Commission				
Southwest Gas Corporation	07/24	Southwest Gas Corporation	Docket No. A24-09-001	Return on Equity
San Gabriel Valley Water Company	05/23	San Gabriel Valley Water Company	Docket No. A23-05-001	Return on Equity
City of Edmonton, Canada				
EPCOR Water Services, Inc.	05/24	EPCOR Water Services, Inc.	Performance Based Regulation Application	Cost of Capital
Colorado Public Utilities Commission				
Atmos Energy Corporation	08/22	Atmos Energy Corporation	Docket No. 22AL-0348G	Rate of Return
Summit Utilities, Inc.	04/18	Colorado Natural Gas Company	Docket No. 18AL-0305G	Rate of Return
Atmos Energy Corporation	06/17	Atmos Energy Corporation	Docket No. 17AL-0429G	Rate of Return

Sponsor	Date	Case/Applicant	Docket No.	Subject
Commission of the Canada Energy Regulator				
Trans-Northern Pipelines Inc.	11/22	Trans-Northern Pipelines Inc.	Docket No. C-22197	Cost of Capital
Delaware Public Service Commission				
Delmarva Power & Light Co.	09/24	Delmarva Power & Light Co.	Docket No. 24-1044 (Gas)	Return on Equity
Tidewater Utilities, Inc.	08/24	Tidewater Utilities, Inc.	Docket No. 24-0991	Rate of Return
Delmarva Power & Light Co.	07/24	Delmarva Power & Light Co.	Docket No. 24-0868	Alternative Forms of Rate Regulation
Artesian Water Company, Inc.	04/23	Artesian Water Company, Inc.	Docket No. 23-0601	Rate of Return
Delmarva Power & Light Co.	12/22	Delmarva Power & Light Co.	Docket No. 22-0897 (Electric)	Return on Equity
Delmarva Power & Light Co.	01/22	Delmarva Power & Light Co.	Docket No. 22-002 (Gas)	Return on Equity
Delmarva Power & Light Co.	11/20	Delmarva Power & Light Co.	Docket No. 20-0149 (Electric)	Return on Equity
Delmarva Power & Light Co.	10/20	Delmarva Power & Light Co.	Docket No. 20-0150 (Gas)	Return on Equity
Tidewater Utilities, Inc.	11/13	Tidewater Utilities, Inc.	Docket No. 13-466	Capital Structure
Public Service Commission of the District of Columbia				
Washington Gas Light Company	08/24	Washington Gas Light Company	Formal Case No. 1180	Rate of Return
Washington Gas Light Company	04/22	Washington Gas Light Company	Formal Case No. 1169	Rate of Return
Washington Gas Light Company	09/20	Washington Gas Light Company	Formal Case No. 1162	Rate of Return
Federal Energy Regulatory Commission				
LS Power Grid California, LLC	10/20	LS Power Grid California, LLC	Docket No. ER21-195-000	Rate of Return
Florida Public Service Commission				
Peoples Gas System, Inc.	03/25	Peoples Gas System, Inc.	Docket No. 20250029-GU	Return on Equity
Tampa Electric Company	04/24	Tampa Electric Company	Docket No. 20240025-EI	Return on Equity
Peoples Gas System, Inc.	04/23	Peoples Gas System, Inc.	Docket No. 20230023-GU	Rate of Return
Tampa Electric Company	04/21	Tampa Electric Company	Docket No. 20210034-EI	Return on Equity
Peoples Gas System, Inc.	09/20	Peoples Gas System, Inc.	Docket No. 20200051-GU	Rate of Return
Utilities, Inc. of Florida	06/20	Utilities, Inc. of Florida	Docket No. 20200139-WS	Rate of Return
Hawaii Public Utilities Commission				
Kaupulehu Waste Water Company	02/25	Kaupulehu Waste Water Company	Docket No. 2023-0456	Rate of Return
Launiupoko Irrigation Company, Inc.	12/20	Launiupoko Irrigation Company, Inc.	Docket No. 2020-0217 / Transferred to 2020-0089	Capital Structure
Lanai Water Company, Inc.	12/19	Lanai Water Company, Inc.	Docket No. 2019-0386	Cost of Service / Rate Design
Manele Water Resources, LLC	08/19	Manele Water Resources, LLC	Docket No. 2019-0311	Cost of Service / Rate Design
Kaupulehu Water Company	02/18	Kaupulehu Water Company	Docket No. 2016-0363	Rate of Return
Aqua Engineers, LLC	05/17	Puhi Sewer & Water Company	Docket No. 2017-0118	Cost of Service / Rate Design
Hawaii Resources, Inc.	09/16	Laie Water Company	Docket No. 2016-0229	Cost of Service / Rate Design
Illinois Commerce Commission				
Ameren Illinois Company d/b/a Ameren Illinois	01/25	Ameren Illinois Company d/b/a Ameren Illinois	Docket No. 25-0084 (Gas)	Return on Equity
Aqua Illinois, Inc.	01/24	Aqua Illinois, Inc.	Docket No. 24-0044	Rate of Return
Ameren Illinois Company d/b/a Ameren Illinois	01/23	Ameren Illinois Company d/b/a Ameren Illinois	Docket No. 23-0082 (Electric)	Return on Equity

Sponsor	Date	Case/Applicant	Docket No.	Subject
Ameren Illinois Company d/b/a Ameren Illinois	01/23	Ameren Illinois Company d/b/a Ameren Illinois	Docket No. 23-0067 (Gas)	Return on Equity
Utility Services of Illinois, Inc.	02/21	Utility Services of Illinois, Inc.	Docket No. 21-0198	Rate of Return
Ameren Illinois Company d/b/a Ameren Illinois	07/20	Ameren Illinois Company d/b/a Ameren Illinois	Docket No. 20-0308	Return on Equity
Utility Services of Illinois, Inc.	11/17	Utility Services of Illinois, Inc.	Docket No. 17-1106	Cost of Service / Rate Design
Aqua Illinois, Inc.	04/17	Aqua Illinois, Inc.	Docket No. 17-0259	Rate of Return
Utility Services of Illinois, Inc.	04/15	Utility Services of Illinois, Inc.	Docket No. 14-0741	Rate of Return
Indiana Utility Regulatory Commission				
Aqua Indiana, Inc.	03/16	Aqua Indiana, Inc. Aboite Wastewater Division	Docket No. 44752	Rate of Return
Twin Lakes, Utilities, Inc.	08/13	Twin Lakes, Utilities, Inc.	Docket No. 44388	Rate of Return
Kansas Corporation Commission				
Atmos Energy Corporation	07/19	Atmos Energy Corporation	19-ATMG-525-RTS	Rate of Return
Kentucky Public Service Commission				
PPL Corporation	05/25	Kentucky Utilities Company / Louisville Gas & Electric Company	2025-00113 / 00114	Rate of Return
Atmos Energy Corporation	09/24	Atmos Energy Corporation	2024-00276	Rate of Return
Bluegrass Water Utility Operating Company	02/23	Bluegrass Water Utility Operating Company	2022-00432	Return on Equity
Atmos Energy Corporation	07/22	Atmos Energy Corporation	2022-00222	PRP Rider Rate
Water Service Corporation of KY	06/22	Water Service Corporation of KY	2022-00147	Rate of Return
Atmos Energy Corporation	07/21	Atmos Energy Corporation	2021-00304	PRP Rider Rate
Atmos Energy Corporation	06/21	Atmos Energy Corporation	2021-00214	Rate of Return
Duke Energy Kentucky, Inc.	06/21	Duke Energy Kentucky, Inc.	2021-00190	Return on Equity
Bluegrass Water Utility Operating Company	10/20	Bluegrass Water Utility Operating Company	2020-00290	Return on Equity
Louisiana Public Service Commission				
Utilities, Inc. of Louisiana	05/21	Utilities, Inc. of Louisiana	Docket No. U-36003	Rate of Return
Southwestern Electric Power Company	12/20	Southwestern Electric Power Company	Docket No. U-35441	Return on Equity
Atmos Energy Corporation	04/20	Atmos Energy Corporation	Docket No. U-35535	Rate of Return
Louisiana Water Service, Inc.	06/13	Louisiana Water Service, Inc.	Docket No. U-32848	Rate of Return
Maine Public Utilities Commission				
Northern Utilities, Inc. d/b/a Unitil	05/23	Northern Utilities, Inc. d/b/a Unitil	Docket No. 2023-00051	Return on Equity
Summit Natural Gas of Maine, Inc.	03/22	Summit Natural Gas of Maine, Inc.	Docket No. 2022-00025	Rate of Return
The Maine Water Company	09/21	The Maine Water Company	Docket No. 2021-00053	Rate of Return
Maryland Public Service Commission				
Washington Gas Light Company	05/23	Washington Gas Light Company	Case No. 9704	Rate of Return
FirstEnergy Service Company	03/23	Potomac Edison Company	Case No. 9695	Rate of Return
Washington Gas Light Company	08/20	Washington Gas Light Company	Case No. 9651	Rate of Return
FirstEnergy Corporation	08/18	Potomac Edison Company	Case No. 9490	Rate of Return
Massachusetts Department of Public Utilities				
Unitil Corporation	09/23	Fitchburg Gas & Electric Co. (Elec.)	D.P.U. 23-80	Rate of Return
Unitil Corporation	09/23	Fitchburg Gas & Electric Co. (Gas)	D.P.U. 23-81	Rate of Return

Sponsor	Date	Case/Applicant	Docket No.	Subject
Unitil Corporation	12/19	Fitchburg Gas & Electric Co. (Elec.)	D.P.U. 19-130	Rate of Return
Unitil Corporation	12/19	Fitchburg Gas & Electric Co. (Gas)	D.P.U. 19-131	Rate of Return
Liberty Utilities	07/15	Liberty Utilities d/b/a New England Natural Gas Company	D.P.U. 15-75	Rate of Return
Minnesota Public Utilities Commission				
Northern States Power Company	11/01	Northern States Power Company	Docket No. G002/GR-21-678	Return on Equity
Northern States Power Company	10/21	Northern States Power Company	Docket No. E002/GR-21-630	Return on Equity
Northern States Power Company	11/20	Northern States Power Company	Docket No. E002/GR-20-723	Return on Equity
Mississippi Public Service Commission				
Atmos Energy Corporation	06/25	Atmos Energy Corporation	Docket No. 2025-UN-59	Rate of Return
Great River Utility Operating Co.	07/22	Great River Utility Operating Co.	Docket No. 2022-UN-86	Rate of Return
Atmos Energy Corporation	03/19	Atmos Energy Corporation	Docket No. 2015-UN-049	Capital Structure
Atmos Energy Corporation	07/18	Atmos Energy Corporation	Docket No. 2015-UN-049	Capital Structure
Missouri Public Service Commission				
Confluence Rivers Utility Operating Company, Inc.	01/23	Confluence Rivers Utility Operating Company, Inc.	Case No. WR-2023-0006/SR-2023-0007	Rate of Return
Spire Missouri, Inc.	12/20	Spire Missouri, Inc.	Case No. GR-2021-0108	Return on Equity
Indian Hills Utility Operating Company, Inc.	10/17	Indian Hills Utility Operating Company, Inc.	Case No. SR-2017-0259	Rate of Return
Raccoon Creek Utility Operating Company, Inc.	09/16	Raccoon Creek Utility Operating Company, Inc.	Case No. SR-2016-0202	Rate of Return
Public Utilities Commission of Nevada				
Southwest Gas Corporation	09/23	Southwest Gas Corporation	Docket No. 23-09012	Return on Equity
Southwest Gas Corporation	09/21	Southwest Gas Corporation	Docket No. 21-09001	Return on Equity
Southwest Gas Corporation	08/20	Southwest Gas Corporation	Docket No. 20-02023	Return on Equity
New Hampshire Public Utilities Commission				
Unitil Energy Systems, Inc.	5/25	Unitil Corporation	Docket No. DE 25-025	Return on Equity
Aquarion Water Company of New Hampshire, Inc.	12/20	Aquarion Water Company of New Hampshire, Inc.	Docket No. DW 20-184	Rate of Return
New Jersey Board of Public Utilities				
Atlantic City Electric Company	11/24	Atlantic City Electric Company	Docket No. ER24110854	Rate of Return
New Jersey Natural Gas Company	01/24	New Jersey Natural Gas Company	Docket No. GR24010071	Rate of Return
Middlesex Water Company	05/23	Middlesex Water Company	Docket No. WR23050292	Rate of Return
FirstEnergy Service Company	03/23	Jersey Central Power & Light Co.	Docket No. ER23030144	Rate of Return
Atlantic City Electric Company	02/23	Atlantic City Electric Company	Docket No. ER23020091	Return on Equity
Middlesex Water Company	05/21	Middlesex Water Company	Docket No. WR21050813	Rate of Return
Atlantic City Electric Company	12/20	Atlantic City Electric Company	Docket No. ER20120746	Return on Equity
FirstEnergy Service Company	02/20	Jersey Central Power & Light Co.	Docket No. ER20020146	Rate of Return
Aqua New Jersey, Inc.	12/18	Aqua New Jersey, Inc.	Docket No. WR18121351	Rate of Return
Middlesex Water Company	10/17	Middlesex Water Company	Docket No. WR17101049	Rate of Return
Middlesex Water Company	03/15	Middlesex Water Company	Docket No. WR15030391	Rate of Return
The Atlantic City Sewerage Company	10/14	The Atlantic City Sewerage Company	Docket No. WR14101263	Cost of Service / Rate Design
Middlesex Water Company	11/13	Middlesex Water Company	Docket No. WR1311059	Capital Structure
New Mexico Public Regulation Commission				
New Mexico Gas Company	09/23	New Mexico Gas Company	Case No. 23-00255-UT	Return on Equity

Sponsor	Date	Case/Applicant	Docket No.	Subject
Southwestern Public Service Co.	11/22	Southwestern Public Service Co.	Case No. 22-00286-UT	Return on Equity
Southwestern Public Service Co.	01/21	Southwestern Public Service Co.	Case No. 20-00238-UT	Return on Equity
North Carolina Utilities Commission				
Pluris Hampstead, LLC	09/24	Pluris Hampstead, LLC	Docket No. W-1305, Sub 38	Rate of Return
Old North State Water Co., Inc.	06/24	Old North State Water Co., Inc.	Docket No. W-1300, Sub 100	Rate of Return
Carolina Water Service, Inc.	07/22	Carolina Water Service, Inc.	Docket No. W-354 Sub 400	Rate of Return
Aqua North Carolina, Inc.	06/22	Aqua North Carolina, Inc.	Docket No. W-218 Sub 573	Rate of Return
Carolina Water Service, Inc.	07/21	Carolina Water Service, Inc.	Docket No. W-354 Sub 384	Rate of Return
Piedmont Natural Gas Co., Inc.	03/21	Piedmont Natural Gas Co., Inc.	Docket No. G-9, Sub 781	Return on Equity
Duke Energy Carolinas, LLC	07/20	Duke Energy Carolinas, LLC	Docket No. E-7, Sub 1214	Return on Equity
Duke Energy Progress, LLC	07/20	Duke Energy Progress, LLC	Docket No. E-2, Sub 1219	Return on Equity
Aqua North Carolina, Inc.	12/19	Aqua North Carolina, Inc.	Docket No. W-218 Sub 526	Rate of Return
Carolina Water Service, Inc.	06/19	Carolina Water Service, Inc.	Docket No. W-354 Sub 364	Rate of Return
Carolina Water Service, Inc.	09/18	Carolina Water Service, Inc.	Docket No. W-354 Sub 360	Rate of Return
Aqua North Carolina, Inc.	07/18	Aqua North Carolina, Inc.	Docket No. W-218 Sub 497	Rate of Return
North Dakota Public Service Commission				
Northern States Power Company	09/21	Northern States Power Company	Case No. PU-21-381	Rate of Return
Northern States Power Company	11/20	Northern States Power Company	Case No. PU-20-441	Rate of Return
Public Utilities Commission of Ohio				
FirstEnergy	06/24	Ohio Edison Co., Cleveland Electric Illuminating Co., Toledo Edison Co.	Case No. 24-0468-EL-AIR	Rate of Return
Aqua Ohio, Inc.	11/22	Aqua Ohio, Inc.	Case No. 22-1094-WW-AIR	Rate of Return
Duke Energy Ohio, Inc.	10/21	Duke Energy Ohio, Inc.	Case No. 21-887-EL-AIR	Return on Equity
Aqua Ohio, Inc.	07/21	Aqua Ohio, Inc.	Case No. 21-0595-WW-AIR	Rate of Return
Aqua Ohio, Inc.	05/16	Aqua Ohio, Inc.	Case No. 16-0907-WW-AIR	Rate of Return
Pennsylvania Public Utility Commission				
Valley Energy, Inc.	04/25	C&T Enterprises	Docket No. R-2025-3054393	Rate of Return
Wellsboro Electric Company	04/25	C&T Enterprises	Docket No. R-2025-3054392	Rate of Return
Citizens' Electric Company of Lewisburg	04/25	C&T Enterprises	Docket No. R-2025-3054394	Rate of Return
FirstEnergy	04/24	Pennsylvania Electric Company	Docket No. R-2024-3047068	Rate of Return
Columbia Water Company	05/23	Columbia Water Company	Docket No. R-2023-3040258	Rate of Return
Borough of Ambler	06/22	Borough of Ambler – Bureau of Water	Docket No. R-2022-3031704	Rate of Return
Citizens' Electric Company of Lewisburg	05/22	C&T Enterprises	Docket No. R-2022-3032369	Rate of Return
Valley Energy Company	05/22	C&T Enterprises	Docket No. R-2022-3032300	Rate of Return
Community Utilities of Pennsylvania, Inc.	04/21	Community Utilities of Pennsylvania, Inc.	Docket No. R-2021-3025207	Rate of Return
Vicinity Energy Philadelphia, Inc.	04/21	Vicinity Energy Philadelphia, Inc.	Docket No. R-2021-3024060	Rate of Return
Delaware County Regional Water Control Authority	02/20	Delaware County Regional Water Control Authority	Docket No. A-2019-3015173	Valuation
Valley Energy, Inc.	07/19	C&T Enterprises	Docket No. R-2019-3008209	Rate of Return
Wellsboro Electric Company	07/19	C&T Enterprises	Docket No. R-2019-3008208	Rate of Return

Sponsor	Date	Case/Applicant	Docket No.	Subject
Citizens' Electric Company of Lewisburg	07/19	C&T Enterprises	Docket No. R-2019-3008212	Rate of Return
Steelton Borough Authority	01/19	Steelton Borough Authority	Docket No. A-2019-3006880	Valuation
Mahoning Township, PA	08/18	Mahoning Township, PA	Docket No. A-2018-3003519	Valuation
SUEZ Water Pennsylvania Inc.	04/18	SUEZ Water Pennsylvania Inc.	Docket No. R-2018-000834	Rate of Return
Columbia Water Company	09/17	Columbia Water Company	Docket No. R-2017-2598203	Rate of Return
Veolia Energy Philadelphia, Inc.	06/17	Veolia Energy Philadelphia, Inc.	Docket No. R-2017-2593142	Rate of Return
Emporium Water Company	07/14	Emporium Water Company	Docket No. R-2014-2402324	Rate of Return
Columbia Water Company	07/13	Columbia Water Company	Docket No. R-2013-2360798	Rate of Return
Penn Estates Utilities, Inc.	12/11	Penn Estates, Utilities, Inc.	Docket No. R-2011-2255159	Capital Structure / Long-Term Debt Cost Rate
South Carolina Public Service Commission				
Blue Granite Water Co.	12/19	Blue Granite Water Company	Docket No. 2019-292-WS	Rate of Return
Carolina Water Service, Inc.	02/18	Carolina Water Service, Inc.	Docket No. 2017-292-WS	Rate of Return
Carolina Water Service, Inc.	06/15	Carolina Water Service, Inc.	Docket No. 2015-199-WS	Rate of Return
Carolina Water Service, Inc.	11/13	Carolina Water Service, Inc.	Docket No. 2013-275-WS	Rate of Return
United Utility Companies, Inc.	09/13	United Utility Companies, Inc.	Docket No. 2013-199-WS	Rate of Return
Utility Services of South Carolina, Inc.	09/13	Utility Services of South Carolina, Inc.	Docket No. 2013-201-WS	Rate of Return
Tega Cay Water Services, Inc.	11/12	Tega Cay Water Services, Inc.	Docket No. 2012-177-WS	Capital Structure
South Dakota Public Service Commission				
Northern States Power Company	06/22	Northern States Power Company	Docket No. EL22-017	Rate of Return
Tennessee Public Utility Commission				
CSWR – Limestone Water Utility Operating Company	07/24	CSWR – Limestone Water Utility Operating Company	Docket No. 24-00044	Capital Structure, Cost of Debt, Return on Equity
Piedmont Natural Gas Company	07/20	Piedmont Natural Gas Company	Docket No. 20-00086	Return on Equity
Public Utility Commission of Texas				
CSWR TX Utility Operating Co, LLC	12/24	CSWR TX Utility Operating Co, LLC	Docket No. 57386	Rate of Return
BVRT Utility Holding Co., LLC	07/24	Texas Water Utilities, LP	Docket No. 56664	Rate of Return
Texas Water Utilities, LP	06/24	Texas Water Utilities, LP	Docket No. 56665	Rate of Return
Southwestern Public Service Co.	02/23	Southwestern Public Service Co.	Docket No. 54634	Return on Equity
CSWR – Texas Utility Operating Company, LLC	02/23	CSWR – Texas Utility Operating Company, LLC	Docket No. 54565	Rate of Return
Oncor Electric Delivery Co. LLC	05/22	Oncor Electric Delivery Co. LLC	Docket No. 53601	Return on Equity
Southwestern Public Service Co.	02/21	Southwestern Public Service Co.	Docket No. 51802	Return on Equity
Southwestern Electric Power Co.	10/20	Southwestern Electric Power Co.	Docket No. 51415	Rate of Return
Texas Railroad Commission				
Atmos Energy Corporation – Mid-Texas Division	11/24	Atmos Energy Corporation – Mid-Texas Division	Docket No. OS-24-00019196	Return on Equity
Atmos Energy Corporation – West Texas Division	10/24	Atmos Energy Corporation – West Texas Division	Docket No. OS-24-00018879	Return on Equity
Atmos Pipeline – Texas, a Division of Atmos Energy Corporation	05/23	Atmos Pipeline – Texas, a Division of Atmos Energy Corporation	Docket No. OS-23-00013758	Return on Equity
Virginia State Corporation Commission				

Sponsor	Date	Case/Applicant	Docket No.	Subject
Aqua Virginia, Inc.	07/23	Aqua Virginia, Inc.	PUR-2023-00073	Rate of Return
Washington Gas Light Company	06/22	Washington Gas Light Company	PUR-2022-00054	Return on Equity
Virginia Natural Gas, Inc.	04/21	Virginia Natural Gas, Inc.	PUR-2020-00095	Return on Equity
Massanutten Public Service Corporation	12/20	Massanutten Public Service Corporation	PUE-2020-00039	Return on Equity
Aqua Virginia, Inc.	07/20	Aqua Virginia, Inc.	PUR-2020-00106	Rate of Return
WGL Holdings, Inc.	07/18	Washington Gas Light Company	PUR-2018-00080	Rate of Return
Atmos Energy Corporation	05/18	Atmos Energy Corporation	PUR-2018-00014	Rate of Return
Aqua Virginia, Inc.	07/17	Aqua Virginia, Inc.	PUR-2017-00082	Rate of Return
Massanutten Public Service Corp.	08/14	Massanutten Public Service Corp.	PUE-2014-00035	Rate of Return / Rate Design
Public Service Commission of West Virginia				
FirstEnergy Service Company	05/23	Monongahela Power Company and The Potomac Edison Company	Case No. 23-0460-E-42T	Return on Equity
FirstEnergy Service Company	12/21	Monongahela Power Company and The Potomac Edison Company	Case No. 21-0857-E-CN (ELG)	Return on Equity
FirstEnergy Service Company	11/21	Monongahela Power Company and The Potomac Edison Company	Case No. 21-0813-E-P (Solar)	Return on Equity

Valley Energy, Inc. / Citizens' Electric Company of Lewisburg, PA / Wellsboro Electric Company

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of Dylan W. D'Ascendis

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Valley Energy, Inc. / Citizens' Electric Company of Lewisburg, PA / Wellsboro Electric Company
Brief Summary of Common Equity Cost Rate

Line No.	Principal Methods	Proxy Group of Seven Natural Gas Distribution Companies	Proxy Group of Fifteen Electric Companies
1.	Discounted Cash Flow Model (DCF) (1)	10.29%	10.32%
2.	Risk Premium Model (RPM) (2)	10.86%	10.79%
3.	Capital Asset Pricing Model (CAPM) (3)	11.12%	10.75%
4.	Market Models Applied to Comparable Risk, Non-Price Regulated Companies (4)	11.92%	11.84%
5.	Indicated Common Equity Cost Rate before Adjustment for Unique Risk	10.29% - 11.92%	10.32% - 11.84%
6.	Size Risk Adjustment (5)	1.00%	0.85%
7.	Performance Factor Adjustment (6)	0.05%	0.05%
8.	Indicated Common Equity Cost Rate after Adjustment	11.34% - 12.97%	11.22% - 12.74%
9.	Recommended Common Equity Cost Rate	11.65%	11.65%

Notes:
(1) From page 1 of Schedule DWD-3.
(2) From page 1 of Schedule DWD-4.
(3) From page 1 of Schedule DWD-5.
(4) From page 1 of Schedule DWD-7.
(5) Adjustment to reflect Valley Energy, Inc.'s, Citizens' Electric Company, and Wellsboro Electric Company's greater business risk due to their smaller sizes relative to the Utility Proxy Groups as detailed in the Direct Testimony of Mr. D'Ascendis.
(6) Performance factor adjustment as explained in the Companies' Direct Testimony.

Proxy Group of Seven Natural Gas Distribution Companies
Capitalization and Financial Statistics (1)
2019 - 2023, Inclusive

	2023	2022	2021	2020	2019	5 YEAR AVERAGE
			(MILLIONS OF DOLLARS)			
Capitalization Statistics						
Amount of Capital Employed						
Total Permanent Capital	$9,183.685	$8,210.117	$7,442.590	$6,654.657	$5,863.473	
Short-Term Debt	$745.215	$823.046	$628.829	$300.871	$554.766	
Total Capital Employed	$9,928.900	$9,033.163	$8,071.419	$6,955.528	$6,418.239	
Indicated Average Capital Cost Rates (2)						
Total Debt	4.10 %	3.17 %	2.90 %	3.39 %	3.74 %	
Preferred Stock	5.22 %	4.84 %	5.33 %	6.19 %	4.60 %	
Capital Structure Ratios						
Based on Total Permanent Capital:						
Long-Term Debt	52.23 %	51.17 %	51.57 %	50.16 %	46.87 %	50.40 %
Preferred Stock	0.87	1.84	1.98	1.53	1.65	1.57
Common Equity	46.90	46.99	46.45	48.31	51.48	48.03
Total	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %
Based on Total Capital:						
Total Debt, Including Short-Term Debt	54.91 %	55.90 %	56.24 %	53.27 %	51.14 %	54.24 %
Preferred Stock	0.75	1.64	1.87	1.43	1.45	1.42
Common Equity	44.34	42.46	41.89	45.30	47.41	44.34
Total	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %
Financial Statistics						
Financial Ratios - Market Based						
Earnings / Price Ratio	5.42 %	4.18 %	5.24 %	3.85 %	3.97 %	4.53 %
Market / Average Book Ratio	156.78	180.83	170.62	184.68	219.63	182.51
Dividend Yield	3.79	3.29	3.46	3.14	2.60	3.26
Dividend Payout Ratio	70.31	58.56	61.19	78.10	67.01	67.03
Rate of Return on Average Book Common Equity	8.63 %	8.06 %	9.49 %	7.11 %	8.74 %	8.41 %
Total Debt / EBITDA (3)	5.18 x	5.39 x	5.59 x	5.72 x	4.81 x	5.34 x
Funds from Operations / Total Debt (4)	27.32 %	11.51 %	9.24 %	14.20 %	15.23 %	15.50 %
Total Debt / Total Capital	54.91 %	55.90 %	56.24 %	53.27 %	51.14 %	54.29 %

Notes:
(1) All capitalization and financial statistics for the group are the arithmetic average of the achieved results for each individual company in the group, and are based upon financial statements as originally reported in each year.

(2) Computed by relating actual total debt interest or preferred stock dividends booked to average of beginning and ending total debt or preferred stock reported to be outstanding.

(3) Total debt relative to EBITDA (Earnings before Interest, Income Taxes, Depreciation and Amortization).

(4) Funds from operations (sum of net income, depreciation, amortization, net deferred income tax and investment tax credits, less total AFUDC) plus interest charges as a percentage of total debt.

Source of Information: Company Annual Forms 10-K.

Proxy Group of Fifteen Electric Companies
Capitalization and Financial Statistics (1)
2019 - 2023, Inclusive

	2023	2022	2021	2020	2019	
			(MILLIONS OF DOLLARS)			
Capitalization Statistics						
Amount of Capital Employed						
Total Permanent Capital	$35,135.635	$33,005.151	$30,958.714	$28,756.784	$26,766.057	
Short-Term Debt	$1,060.785	$1,196.389	$998.605	$820.719	$880.673	
Total Capital Employed	$36,196.420	$34,201.540	$31,957.319	$29,577.503	$27,646.730	
Indicated Average Capital Cost Rates (2)						
Total Debt	4.33 %	3.78 %	3.65 %	4.09 %	4.13 %	
Preferred Stock	5.13 %	5.86 %	7.09 %	5.58 %	5.34 %	
Capital Structure Ratios						5 YEAR AVERAGE
Based on Total Permanent Capital:						
Long-Term Debt	58.19 %	57.43 %	56.89 %	55.65 %	54.09 %	56.45 %
Preferred Stock	0.53	0.49	0.54	0.71	0.83	0.62
Common Equity	41.28	42.08	42.57	43.64	45.08	42.93
Total	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %
Based on Total Capital:						
Total Debt, Including Short-Term Debt	59.30 %	58.56 %	58.04 %	56.67 %	55.17 %	57.55 %
Preferred Stock	0.53	0.47	0.51	0.68	0.81	0.60
Common Equity	40.17	40.97	41.45	42.65	44.02	41.85
Total	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %
Financial Statistics						
Financial Ratios - Market Based						
Earnings / Price Ratio	5.41 %	4.95 %	5.43 %	4.30 %	5.31 %	5.08 %
Market / Average Book Ratio	177.32	194.85	194.85	184.99	193.03	189.01
Dividend Yield	3.93	3.79	3.77	3.68	3.40	3.71
Dividend Payout Ratio	79.39	79.13	69.93	64.92	66.11	71.89
Rate of Return on Average Book Common Equity	9.19 %	9.21 %	10.12 %	8.03 %	9.91 %	9.29 %
Total Debt / EBITDA (3)	5.53 x	5.51 x	5.31 x	5.98 x	4.73 x	5.41 x
Funds from Operations / Total Debt (4)	12.87 %	10.48 %	6.06 %	12.20 %	13.34 %	10.99 %
Total Debt / Total Capital	59.30 %	58.56 %	58.04 %	56.67 %	55.17 %	57.55 %

Notes:

(1) All capitalization and financial statistics for the group are the arithmetic average of the achieved results for each individual company in the group, and are based upon financial statements as originally reported in each year.

(2) Computed by relating actual total debt interest or preferred stock dividends booked to average of beginning and ending total debt or preferred stock reported to be outstanding.

(3) Total debt relative to EBITDA (Earnings before Interest, Income Taxes, Depreciation and Amortization).

(4) Funds from operations (sum of net income, depreciation, amortization, net deferred income tax and investment tax credits, less total AFUDC) plus interest charges as a percentage of total debt.

Source of Information: Company Annual Forms 10-K.

Valley Energy, Inc. / Citizens' Electric Company of Lewisburg, PA / Wellsboro Electric Company
Indicated Common Equity Cost Rate Using the Discounted Cash Flow Model for the
Proxy Group of Seven Natural Gas Distribution Companies and Proxy Group of Fifteen Electric Companies

Proxy Group of Seven Natural Gas Distribution Companies	[1] Average Dividend Yield (1)	[2] Value Line Projected Five Year Growth in EPS (2)	[3] Zack's Five Year Projected Growth Rate in EPS	[4] S&P Capital IQ Projected Five Year Growth in EPS	[5] Average Projected Five Year Growth in EPS (3)	[6] Adjusted Dividend Yield (4)	[7] Indicated Common Equity Cost Rate (5)
Atmos Energy Corporation	2.44 %	6.00 %	7.10 %	7.44 %	6.85 %	2.52 %	9.37 %
New Jersey Resources Corporation	3.82	5.00	NA	5.90	5.45	3.92	9.37
NiSource Inc.	2.98	9.50	8.20	7.93	8.54	3.11	11.65
Northwest Natural Holding Company	4.84	6.50	NA	5.50	6.00	4.99	10.99
ONE Gas, Inc.	3.77	4.00	4.70	2.63	3.78	3.84	7.62
Southwest Gas Holdings, Inc.	3.37	10.00	6.60	10.55	9.05	3.52	12.57
Spire Inc.	4.47	4.50	5.80	6.82	5.71	4.60	10.31
						Average	10.27 %
		NA= Not Available				Median	10.31 %
						Average of Mean and Median	10.29 %

Proxy Group of Fifteen Electric Companies	[1] Average Dividend Yield (1)	[2] Value Line Projected Five Year Growth in EPS (2)	[3] Zack's Five Year Projected Growth Rate in EPS	[4] S&P Capital IQ Projected Five Year Growth in EPS	[5] Average Projected Five Year Growth in EPS (3)	[6] Adjusted Dividend Yield (4)	[7] Indicated Common Equity Cost Rate (5)	
Alliant Energy Corporation	3.38 %	6.00 %	6.40 %	6.73 %	6.38 %	3.49 %	9.87 %	
Ameren Corporation	3.05	6.50	6.70	6.79	6.66	3.15	9.81	
American Electric Power Corporation	3.82	6.50	6.00	6.59	6.36	3.94	10.30	
Duke Energy Corporation	3.77	6.00	6.30	6.33	6.21	3.89	10.10	
Edison International	5.01	6.50	8.50	8.25	7.75	5.20	12.95	
Entergy Corporation	3.03	0.50	9.50	8.40	6.13	3.12	9.25	
Evergy, Inc.	4.19	7.50	5.90	5.68	6.36	4.32	10.68	
IDACORP, Inc.	3.09	6.00	8.40	7.00	7.13	3.20	10.33	
North Western Corporation	4.95	4.50	6.10	5.73	5.44	5.08	10.52	
OGE Energy Corporation	3.97	6.50	6.10	6.09	6.23	4.09	10.32	
Pinnacle West Capital Corporation	4.09	4.00	5.60	6.38	5.33	4.20	9.53	
Portland General Electric Company	4.64	5.50	12.30	7.83	8.54	4.84	13.38	(6)
Southern Company	3.41	6.50	6.80	6.62	6.64	3.52	10.16	
TXNM Energy, Inc.	3.33	4.00	3.00	5.68	4.23	3.40	7.63	(6)
Xcel Energy Inc.	3.36	6.50	6.90	7.35	6.92	3.48	10.40	
						Average	10.33 %	
		NA= Not Available				Median	10.30 %	
						Average of Mean and Median	10.32 %	

Notes:

(1) Indicated dividend at 02/28/2025 divided by the average closing price of the last 60 trading days ending 02/28/2025 for each company.
(2) From pages 2 through 23 of this Schedule.
(3) Average of columns 2 through 4 excluding negative growth rates.
(4) This reflects a growth rate component equal to one-half the conclusion of growth rate (from column 5) x column 1 to reflect the periodic payment of dividends (Gordon Model) as opposed to the continuous payment. Thus, for Atmos Energy Corporation, 2.44% x (1+(1/2 x 6.85%)) = 2.52%.
(5) Column 5 + Column 6.
(6) Results were excluded from the final average and median as they were more than two standard deviations from the proxy group's mean.

Source of Information:
Value Line Investment Survey
www.zacks.com Downloaded on 02/28/2025
S&P Capital IQ

ATMOS ENERGY CORP. NYSE-ATO

RECENT PRICE 142.28 | P/E RATIO 19.8 (Trailing: 20.3 Median: 20.0) | RELATIVE P/E RATIO 1.08 | DIV'D YLD 2.5% | VALUE LINE

TIMELINESS 3 Raised 1/17/25
SAFETY 1 Raised 6/6/14
TECHNICAL 3 Lowered 1/24/25
BETA .90 (1.00 = Market)

18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$124-$185	$155 (10%)

2028-30 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	170	(+20%)	*7%*
Low	140	(Nil)	*3%*

Institutional Decisions

	1Q2024	2Q2024	3Q2024
to Buy	367	342	357
to Sell	292	311	315
Hld's(000)	137412	144146	162641

	2028	2029	2030
Target Price Range			

	58.2	64.8	82.0	93.6	100.8	115.2	121.1	105.3	123.0	125.3	152.6	147.7
High:												
Low:	44.2	50.8	60.0	72.5	76.5	89.2	77.9	84.6	97.7	101.0	110.5	136.2

LEGENDS
35.50 x Dividends p sh
Relative Price Strength
Options: Yes
Shaded area indicates recession

% TOT. RETURN 1/25

	THIS STOCK	VL ARITH.* INDEX
1 yr.	30.5	20.7
3 yr.	45.9	25.6
5 yr.	39.7	83.9

2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	© VALUE LINE PUB. LLC	28-30
53.69	53.12	48.15	38.10	42.88	49.22	40.82	32.23	26.01	28.00	24.32	22.41	25.73	29.82	28.79	26.83	***26.30***	***26.20***	Revenues per sh [A]	***32.45***
4.29	4.64	4.72	4.76	5.14	5.42	5.81	6.19	6.62	7.24	7.57	8.03	8.64	9.30	10.04	11.03	***11.55***	***12.25***	"Cash Flow" per sh	***13.90***
1.97	2.16	2.26	2.10	2.50	2.96	3.09	3.38	3.60	4.00	4.35	4.72	5.12	5.60	6.10	6.83	***7.20***	***7.60***	Earnings per sh [AB]	***8.65***
1.32	1.34	1.36	1.38	1.40	1.48	1.56	1.68	1.80	1.94	2.10	2.30	2.50	2.72	2.96	3.22	***3.48***	***3.68***	Div'ds Decl'd per sh [C] ■	***4.45***
5.51	6.02	6.90	8.12	9.32	8.32	9.61	10.46	10.72	13.19	14.19	15.38	14.87	17.35	18.90	18.92	***22.70***	***22.60***	Cap'l Spending per sh	***21.60***
23.52	24.16	24.98	26.14	28.47	30.74	31.48	33.32	36.74	42.87	48.18	53.95	59.71	66.85	73.20	78.31	***83.50***	***85.70***	Book Value per sh	***97.30***
92.55	90.16	90.30	90.24	90.64	100.39	101.48	103.93	106.10	111.27	119.34	125.88	132.42	140.90	148.49	155.26	***163.00***	***168.00***	Common Shs Outst'g [D]	***185.00***
12.5	13.2	14.4	15.9	15.9	16.1	17.5	20.8	22.0	21.7	23.2	22.3	18.8	19.3	18.7	17.3	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	***18.0***
.83	.84	.90	1.01	.89	.85	.88	1.09	1.11	1.17	1.24	1.15	1.02	1.12	1.08	.90			Relative P/E Ratio	***1.00***
5.3%	4.7%	4.2%	4.1%	3.5%	3.1%	2.9%	2.4%	2.3%	2.2%	2.1%	2.2%	2.6%	2.5%	2.6%	2.7%			Avg Ann'l Div'd Yield	***2.9%***
4142.1	3349.9	2759.7	3115.5	2901.8	2821.1	3407.5	4201.7	4275.4	4165.2	***4290***	***4400***	Revenues ($mill) [A]	***6000***
315.1	350.1	382.7	444.3	511.4	580.5	665.6	774.4	885.9	1042.9	***1150***	***1255***	Net Profit ($mill)	***1575***
38.3%	36.4%	36.6%	27.0%	21.4%	19.5%	18.8%	9.1%	11.4%	15.6%	***18.5%***	***19.0%***	Income Tax Rate	***25.0%***
7.6%	10.5%	13.9%	14.3%	17.6%	20.6%	19.5%	18.4%	20.7%	25.0%	***26.8%***	***28.5%***	Net Profit Margin	***26.3%***
43.5%	38.7%	44.0%	34.3%	38.0%	40.0%	38.4%	37.9%	37.9%	39.3%	***40.0%***	***40.0%***	Long-Term Debt Ratio	***40.0%***
56.5%	61.3%	56.0%	65.7%	62.0%	60.0%	61.6%	62.1%	62.1%	60.7%	***60.0%***	***60.0%***	Common Equity Ratio	***60.0%***
5650.2	5651.8	6965.7	7263.6	9279.7	11323	12837	15180	17509	20018	***22750***	***24000***	Total Capital ($mill)	***30000***
7430.6	8280.5	9259.2	10371	11788	13355	15064	17240	19607	22204	***24600***	***26000***	Net Plant ($mill)	***32000***
6.6%	7.2%	6.4%	6.9%	6.1%	5.5%	5.5%	5.4%	5.5%	5.7%	***6.5%***	***6.5%***	Return on Total Cap'l	***6.5%***
9.9%	10.1%	9.8%	9.3%	8.9%	8.5%	8.4%	8.2%	8.1%	8.6%	***8.5%***	***8.5%***	Return on Shr. Equity	***9.0%***
9.9%	10.1%	9.8%	9.3%	8.9%	8.5%	8.4%	8.2%	8.1%	8.6%	***8.5%***	***8.5%***	Return on Com Equity	***9.0%***
4.9%	5.1%	4.9%	4.8%	4.6%	4.4%	4.3%	4.2%	4.2%	4.5%	***4.5%***	***4.5%***	Retained to Com Eq	***4.0%***
51%	50%	50%	48%	48%	49%	49%	49%	49%	47%	***49%***	***49%***	All Div'ds to Net Prof	***52%***

CAPITAL STRUCTURE as of 12/31/24
Total Debt $8510.1 mill. **Due in 5 Yrs** $1170.0 mill.
LT Debt $8490.2 mill. **LT Interest** $190.0 mill.
(LT interest earned: 7.5x; total interest coverage: 7.5x)
Leases, Uncapitalized Annual rentals $43.2 mill.

Pfd Stock None

Pension Assets-9/24 $595.2 mill.
Oblig. $470.9 mill.
Common Stock 158,728,197 shs.
as of 1/31/25

MARKET CAP: $22.6 billion (Large Cap)

CURRENT POSITION ($MILL.)	2023	2024	12/31/24
Cash Assets	15.4	307.3	584.5
Other	870.4	825.0	1243.6
Current Assets	885.8	1132.3	1828.1
Accts Payable	336.1	445.4	453.0
Debt Due	253.4	9.9	19.9
Other	763.1	750.6	701.9
Current Liab.	1352.6	1205.9	1174.8
Fix. Chg. Cov.	1059%	914%	930%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '22-'24 to '28-'30
Revenues	-4.0%	2.0%	*2.0%*
"Cash Flow"	7.0%	7.0%	*5.5%*
Earnings	9.5%	9.0%	*6.0%*
Dividends	7.5%	9.0%	*7.0%*
Book Value	10.0%	11.5%	*5.0%*

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.) [A] Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2022	1012.8	1649.8	816.4	722.7	4201.7
2023	1484.0	1541.0	662.7	587.7	4275.4
2024	1158.5	1647.2	701.5	658.0	4165.2
2025	1176.0	***1700***	***740***	***674***	***4290***
2026	***1210***	***1730***	***760***	***700***	***4400***

Fiscal Year Ends	EARNINGS PER SHARE [A B E] Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2022	1.86	2.37	.92	.51	5.60
2023	1.91	2.48	.94	.80	6.10
2024	2.08	2.85	1.08	.86	6.83
2025	2.23	***2.92***	***1.15***	***.90***	***7.20***
2026	***2.34***	***3.01***	***1.25***	***1.00***	***7.60***

Calendar	QUARTERLY DIVIDENDS PAID [C] ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	.625	.625	.625	.68	2.56
2022	.68	.68	.68	.74	2.78
2023	.74	.74	.74	.805	3.03
2024	.805	.805	.805	.87	3.29
2025	.87				

BUSINESS: Atmos Energy Corporation is engaged primarily in the distribution and sale of natural gas to over 3.3 million customers through six regulated natural gas utility operations: Louisiana Division, West Texas Division, Mid-Tex Division, Mississippi Division, Colorado-Kansas Division, and Kentucky/Mid-States Division. Gas sales breakdown for fiscal 2024: 68.8%, residential; 27.1%, commercial; 2.7%, industrial; and 1.4% other. The company sold Atmos Energy Marketing, 1/17. Officers and directors own approximately .5% of common stock (12/24 Proxy). President and Chief Executive Officer: Kevin Akers. Incorporated: Texas. Address: Three Lincoln Centre, Suite 1800, 5430 LBJ Freeway, Dallas, Texas 75240. Telephone: 972-934-9227. Internet: www.atmosenergy.com.

Atmos Energy Corporation got off to a decent start in fiscal 2025. (The year concludes on September 30th.) Indeed, for the first quarter, the bottom line advanced 7.2%, to $2.23 per share, which matched our target, compared to fiscal 2024's tally of $2.08. One contributor was the distribution segment, supported partly by rate adjustments and benefits of residential customer growth (both occurring primarily in the Mid-Tex Division). Furthermore, the pipeline and storage unit was aided, among other factors, by the Gas Reliability Infrastructure Program filing approved in May 2024 and the System Safety and Integrity Rider filing approved in November 2024. But the company's results were weighed down, to a certain extent, by increases in bad-debt expense, depreciation, and property taxes, as well as higher interest expense. Nevertheless, we believe that full-year profits will finish in the vicinity of $7.20 a share (unchanged from the estimate in our last report three months ago). That would mark a 5% increase from fiscal 2024's $6.83 figure. Regarding the next fiscal year, earnings per share may grow at a similar percentage rate, to $7.60, assuming additional expansion of operating margins.

The Financial Strength rating is solid, at A. When the December period ended, cash and equivalents were $584.5 million. Moreover, long-term borrowings seemed reasonable (40% of total capital) and short-term debt was only $19.9 million. Too, $6.3 billion in common stock and/or debt securities remained available for issuance (out of $8.0 billion) under a shelf registration statement expiring in December, 2027. Finally, the company had four undrawn revolving credit facilities aggregating $3.1 billion plus a $1.5 billion commercial paper program.

These top-quality shares offer unspectacular long-term total return potential. The dividend yield does not stand out when measured against the average of *Value Line's* Natural Gas Utility group. Also, capital gains potential for the pull to 2028-2030 is nothing to write home about. That's because the stock is already trading within our Target Price Range. Meanwhile, the Timeliness rank resides at just 3 (Average).

Frederick L. Harris, III February 21, 2025

(A) Fiscal year ends Sept. 30th. **(B)** Diluted shrs. Excl. nonrec. gains (loss): '10, 5¢; '11, (1¢); '18, $1.43; '20, 17¢. Excludes discontinued operations: '11, 10¢; '12, 27¢; '13, 14¢; '17, 13¢. Next earnings report due early May. **(C)** Dividends historically paid in early March, June, Sept., and Dec. ■ Div. reinvestment plan. Direct stock purchase plan avail. **(D)** In millions. **(E)** Qtrs may not add due to change in shrs outstanding.

Company's Financial Strength	A
Stock's Price Stability	95
Price Growth Persistence	60
Earnings Predictability	100

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NEW JERSEY RES. NYSE-NJR

RECENT PRICE **45.81** | P/E RATIO **14.8** (Trailing: 13.8 Median: 17.0) | RELATIVE P/E RATIO **0.80** | DIV'D YLD **3.9%** | **VALUE LINE**

TIMELINESS 4 Raised 3/29/24
SAFETY 2 Lowered 4/17/20
TECHNICAL 2 Raised 1/3/25
BETA 1.00 (1.00 = Market)

18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$39-$63	$51 (10%)

2028-30 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	75	(+65%)	*16%*
Low	55	(+20%)	*8%*

Institutional Decisions

	1Q2024	2Q2024	3Q2024
to Buy	167	167	196
to Sell	140	139	134
Hld's(000)	70181	71950	88596

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
High:	32.1	34.1	38.9	45.4	51.8	51.2	44.7	44.4	51.4	55.8	51.9	48.3						
Low:	21.9	26.8	30.5	33.7	35.6	40.3	21.1	33.3	37.8	38.9	39.4	44.9						

LEGENDS
0.40 x Dividends p sh divided by Interest Rate
Relative Price Strength
2-for-1 split 3/15
Options: Yes
Shaded area indicates recession

Target Price Range 2028 | 2029 | 2030

% TOT. RETURN 1/25

	THIS STOCK	VL ARITH.* INDEX
1 yr.	27.8	20.7
3 yr.	39.0	25.6
5 yr.	46.2	83.9

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	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	28-30
Revenues per sh [A]	31.17	32.05	36.30	27.08	38.38	44.40	32.09	21.90	26.28	33.24	29.01	20.39	22.71	30.19	20.12	18.06	*18.30*	*18.80*	*21.45*
"Cash Flow" per sh	1.58	1.63	1.70	1.86	1.93	2.73	2.52	2.46	2.68	3.72	2.99	3.30	3.36	3.84	4.28	4.59	*4.90*	*5.10*	*6.05*
Earnings per sh [B]	1.20	1.23	1.29	1.36	1.37	2.08	1.78	1.61	1.73	2.72	1.96	2.07	2.16	2.50	2.71	2.95	*3.10*	*3.20*	*3.90*
Div'ds Decl'd per sh [C] ■	.62	.68	.72	.77	.81	.86	.93	.98	1.04	1.11	1.19	1.27	1.36	1.45	1.56	1.71	*1.80*	*1.95*	*2.20*
Cap'l Spending per sh	.90	1.05	1.13	1.26	1.33	1.52	3.76	4.15	3.80	4.39	5.83	4.65	5.42	5.81	5.13	5.26	*5.50*	*5.75*	*6.50*
Book Value per sh [D]	8.29	8.81	9.36	9.80	10.65	11.48	12.99	13.58	14.33	16.18	17.37	19.26	17.18	18.88	20.40	22.12	*23.05*	*23.80*	*27.00*
Common Shs Outst'g [E]	83.17	82.35	82.89	83.05	83.32	84.20	85.19	85.88	86.32	87.69	89.34	95.80	94.95	96.25	97.58	99.46	*101.00*	*102.50*	*105.00*
Avg Ann'l P/E Ratio	14.9	15.0	16.8	16.8	16.0	11.7	16.6	21.3	22.4	15.6	24.3	17.7	17.5	17.0	17.6	14.9	*Bold figures are Value Line estimates*		*17.0*
Relative P/E Ratio	.99	.95	1.05	1.07	.90	.62	.84	1.12	1.13	.84	1.29	.91	.95	.98	.98	.77			*.95*
Avg Ann'l Div'd Yield	3.5%	3.7%	3.3%	3.4%	3.7%	3.5%	3.1%	2.9%	2.7%	2.6%	2.5%	3.5%	3.6%	3.4%	3.3%	3.9%			*3.4%*
Revenues ($mill) [A]							2734.0	1880.9	2268.6	2915.1	2592.0	1953.7	2156.6	2906.0	1963.0	1796.5	*1850*	*1925*	*2250*
Net Profit ($mill)							153.7	138.1	149.4	240.5	175.0	196.2	207.7	240.3	264.7	290.8	*315*	*330*	*410*
Income Tax Rate							26.3%	15.5%	17.2%	--	--	--	10.3%	22.0%	15.9%	23.0%	*21.5%*	*22.0%*	*22.0%*
Net Profit Margin							5.6%	7.3%	6.6%	8.2%	6.7%	10.0%	9.6%	8.3%	13.5%	16.2%	*16.9%*	*17.0%*	*18.2%*
Long-Term Debt Ratio							43.2%	47.7%	44.6%	45.4%	49.8%	55.1%	57.0%	57.8%	58.2%	56.7%	*56.5%*	*56.0%*	*55.0%*
Common Equity Ratio							56.8%	52.3%	55.4%	54.6%	50.2%	44.9%	43.0%	42.2%	41.8%	43.3%	*43.5%*	*44.0%*	*45.0%*
Total Capital ($mill)							1950.6	2230.1	2233.7	2599.6	3088.9	4104.2	3793.0	4302.6	4758.8	5079.9	*5350*	*5550*	*6300*
Net Plant ($mill)							2128.3	2407.7	2609.7	2651.0	3041.2	3983.0	4213.5	4649.9	5022.1	5403.2	*5750*	*6000*	*6800*
Return on Total Cap'l							8.6%	6.9%	7.7%	10.1%	6.4%	5.6%	6.5%	6.8%	5.5%	5.7%	*6.0%*	*6.0%*	*6.5%*
Return on Shr. Equity							13.9%	11.8%	12.1%	16.9%	11.3%	10.6%	12.7%	13.2%	13.3%	13.2%	*13.5%*	*13.5%*	*14.5%*
Return on Com Equity							13.9%	11.8%	12.1%	16.9%	11.3%	10.6%	12.7%	13.2%	13.3%	13.2%	*13.5%*	*13.5%*	*14.5%*
Retained to Com Eq							7.0%	4.8%	5.0%	10.2%	4.6%	4.3%	5.6%	6.2%	5.7%	5.7%	*5.5%*	*5.0%*	*6.5%*
All Div'ds to Net Prof							50%	60%	59%	40%	59%	60%	56%	53%	58%	58%	*58%*	*61%*	*56%*

CAPITAL STRUCTURE as of 12/31/24
Total Debt $3418.1 mill. **Due in 5 Yrs** $660 mill.
LT Debt $2989.5 mill. **LT Interest** $130 mill.
Incl. $8.4 mill. capitalized leases.

Pension Assets-9/24 $641 mill.
Oblig. $624 mill.

Pfd Stock None

Common Stock 100,289,422 shs.
as of 1/31/25

MARKET CAP: $4.6 billion (Mid Cap)

CURRENT POSITION ($MILL.)	2023	2024	12/31/24
Cash Assets	1.0	1.0	1.9
Other	531.1	553.6	728.8
Current Assets	532.1	554.6	730.7
Accts Payable	203.1	169.2	112.5
Debt Due	368.3	480.8	428.6
Other	235.2	237.8	277.6
Current Liab.	806.6	887.8	818.7
Fix. Chg. Cov.	331%	480%	695%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '22-'24 to '28-'30
Revenues	-4.5%	-5.0%	*2.5%*
"Cash Flow"	7.0%	6.5%	*5.0%*
Earnings	5.5%	5.0%	*5.0%*
Dividends	7.0%	7.0%	*5.0%*
Book Value	7.0%	5.0%	*4.5%*

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.) [A] Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2022	675.9	912.3	552.3	765.5	2906.0
2023	723.6	644.0	264.1	331.3	1963.0
2024	467.2	657.9	275.6	395.8	1796.5
2025	488.4	*675*	*285*	*401.6*	*1850*
2026	*510*	*700*	*295*	*420*	*1925*

Fiscal Year Ends	EARNINGS PER SHARE [A B] Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2022	.69	1.36	d.04	.49	2.50
2023	1.14	1.16	.10	.31	2.71
2024	.74	1.41	d.09	.89	2.95
2025	1.28	*1.50*	*.Nil*	*.32*	*3.10*
2026	*1.00*	*1.70*	*.10*	*.40*	*3.20*

Calendar	QUARTERLY DIVIDENDS PAID [C] ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	.3325	.3325	.3325	.3625	1.36
2022	.3625	.3625	.3625	.3625	1.45
2023	.39	.39	.39	.39	1.56
2024	.42	.42	.42	.45	1.71
2025	.45				

BUSINESS: New Jersey Resources Corp. is a holding company providing retail/wholesale energy svcs. to customers in NJ, and in states from the Gulf Coast to New England, and Canada. New Jersey Natural Gas had 583,000 cust. at 9/30/24. Fiscal 2024 volume: 158 bill. cu. ft. (16% interruptible, 41% residential, commercial & firm transportation, 43% other). N.J. Natural Energy subsidiary provides unregulated retail/wholesale natural gas and related energy svcs. 2024 dep. rate: 3.2%. Has 1,370 empls. Off./dir. own less than 1% of common; BlackRock, 17.3%; Vanguard, 11.9% (12/24 Proxy). CEO, President & Director: Steven D. Westhoven. Incorporated: New Jersey. Address: 1415 Wyckoff Road, Wall, NJ 07719. Telephone: 732-938-1480. Web: www.njresources.com.

New Jersey Resources finished fiscal 2024 in good shape. (Year ended September 30th.) The company closed out the year with a better-than-expected bottom-line result in the fiscal fourth quarter. Full year earnings per share advanced a solid 9%, to $2.95. September's significant year-over-year increase came from wider fuel margins and lower operations and maintenance expense, offset somewhat by an uptick in depreciation. The company invested more than $500 million over the year, with over 40% of capital expenditures providing immediate returns. Operations at Clean Energy Ventures accelerated throughout the year, with its residential solar portfolio selling out, generating $135 million that will be reinvested, and over 70 megawatts of solar projects either completed or under construction (of 1 gigawatt in the pipeline). The Storage and Transportation business also showed strengths, highlighted by a recent rate case filed for the recovery of investments in the Adelphia Gateway project. The company did well setting up good growth opportunities.

The first quarter of fiscal 2025 was also a standout. The bottom line advanced to $1.28 from $0.74 in the year before. A $157 million annual revenue increase from the natural gas utility rate case settlement, effective November 21st, was a contributing factor. Favorable winter conditions also contributed to the strong operating performance.

We have raised out earnings targets. Notably, we've lifted our fiscal 2025 bottom-line estimate by $0.20, to $3.10 per share. This is in line with management's predictions. We have also initiated targets for 2026 and upped our 3- to 5-year calls. The company is set to invest roughly $1.5 billion over the next two years, targeting infrastructure improvements, clean energy expansion, and storage and transportation efficiency. We also look for the Adelphia rate case to conclude in the current year.

The stock may appeal to conservative long-term accounts. NJR's earnings growth, rooted in a strong regional energy economy, is a solid foundation for returns. Too, the company's steady dividend growth trajectory adds to its overall value. The issue is untimely, however.

Earl B. Humes *February 21, 2025*

(A) Fiscal year ends Sept. 30th.
(B) Diluted earnings. Qtly. revenues and egs. may not sum to total due to rounding and change in shares outstanding. Next earnings report due early May.
(C) Dividends historically paid in early Jan., April, July, and October. ■ Dividend reinvestment plan available.
(D) Includes regulatory assets in 2024: $612.6 million, $6.16/share.
(E) In millions, adjusted for 3/15 split.

Company's Financial Strength	A
Stock's Price Stability	85
Price Growth Persistence	40
Earnings Predictability	65

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NISOURCE INC. NYSE-NI

RECENT PRICE **38.11** | P/E RATIO **21.3** (Trailing: 21.3 Median: 21.0) | RELATIVE P/E RATIO **1.16** | DIV'D YLD **2.9%** | **VALUE LINE**

TIMELINESS 4 Lowered 9/6/24
SAFETY 2 Raised 2/23/24
TECHNICAL 2 Lowered 2/21/25
BETA .95 (1.00 = Market)

18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$26-$44	$35 (-10%)

2028-30 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	55	(+45%)	*12%*
Low	40	(+5%)	*5%*

Institutional Decisions

	1Q2024	2Q2024	3Q2024
to Buy	331	328	334
to Sell	236	249	286
Hld's(000)	425705	439719	484273

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
High:	44.9	49.2	26.9	27.8	28.1	30.7	30.5	27.8	32.6	29.0	38.6	38.8						
Low:	32.1	16.0	19.0	21.7	22.4	24.7	19.6	21.1	23.8	22.9	24.8	35.5						
Revenues per sh	24.02	22.99	21.33	16.31	18.04	20.47	14.58	13.90	14.46	13.74	13.63	11.95	12.09	14.20	12.31	*12.45*	*13.00*	*13.50*
"Cash Flow" per sh	2.96	3.19	2.98	3.13	3.41	3.60	2.27	2.71	2.07	2.86	3.17	3.15	3.26	3.56	3.63	*3.90*	*4.00*	*4.15*
Earnings per sh A	.84	1.06	1.05	1.37	1.57	1.67	.63	1.00	.39	1.30	1.31	1.32	1.37	1.47	1.60	*1.75*	*1.85*	*2.00*
Div'd Decl'd per sh B ■	.92	.92	.92	.94	.98	1.02	.83	.64	.70	.78	.80	.84	.88	.94	1.00	1.06	*1.12*	*1.20*
Cap'l Spending per sh	2.81	2.88	3.99	4.83	5.99	6.42	4.26	4.57	5.03	4.88	4.72	4.49	4.53	5.35	5.91	*5.25*	*5.50*	*6.00*
Book Value per sh C	17.54	17.63	17.71	17.90	18.77	19.54	12.04	12.60	12.82	13.08	13.36	12.44	13.33	14.63	17.40	*22.35*	*23.20*	*23.50*
Common Shs Outst'g D	276.79	279.30	282.18	310.28	313.68	316.04	319.11	323.16	337.02	372.36	382.14	391.76	405.30	412.14	447.38	*470.00*	*485.00*	*500.00*
Avg Ann'l P/E Ratio	14.3	15.3	19.4	17.9	18.9	22.7	37.3	23.2	64.4	19.3	21.3	18.7	18.0	19.6	16.8	*17.5*	*Bold figures are Value Line estimates*	
Relative P/E Ratio	.95	.97	1.22	1.14	1.06	1.19	1.88	1.22	3.24	1.04	1.13	.96	.97	1.13	.93	*.97*		
Avg Ann'l Div'd Yield	7.6%	5.7%	4.5%	3.8%	3.3%	2.7%	3.5%	2.8%	2.8%	3.1%	2.9%	3.4%	3.6%	3.3%	3.7%	3.5%		
Revenues ($mill)							4651.8	4492.5	4874.6	5114.5	5208.9	4681.7	4899.6	5850.6	5505.4	*5850*	*6300*	*6750*
Net Profit ($mill)							198.6	328.1	128.6	478.3	549.8	562.6	626.3	703.3	759.1	*825*	*895*	*1000*
Income Tax Rate							41.6%	35.7%	71.0%	19.7%	17.0%	18.3%	15.7%	16.5%	17.8%	*19.0%*	*19.0%*	*19.0%*
AFUDC % to Net Profit							--	--	--	--	--	--	--	--	2.3%	*3.0%*	*2.5%*	*2.5%*
Long-Term Debt Ratio							60.7%	59.8%	63.5%	55.3%	56.8%	61.6%	56.9%	55.7%	57.2%	*54.0%*	*54.0%*	*55.0%*
Common Equity Ratio							39.3%	40.2%	36.5%	37.9%	36.9%	32.5%	33.5%	35.3%	40.3%	*46.0%*	*46.0%*	*45.0%*
Total Capital ($mill)							9792.0	10129	11832	12856	13843	14972	16131	17099	19325	*22800*	*24450*	*26100*
Net Plant ($mill)							12112	13068	14360	15543	16912	16620	17882	19843	22275	*25750*	*27350*	*29300*
Return on Total Cap'l							4.0%	5.0%	2.6%	5.1%	5.3%	5.0%	4.9%	5.1%	5.0%	*3.5%*	*3.5%*	*4.0%*
Return on Shr. Equity							5.2%	8.1%	3.0%	8.3%	9.2%	9.8%	9.0%	9.3%	9.2%	*8.0%*	*8.0%*	*8.5%*
Return on Com Equity							5.2%	8.1%	3.0%	9.6%	9.7%	10.4%	10.6%	10.8%	9.2%	*8.0%*	*8.0%*	*8.5%*
Retained to Com Eq							NMF	3.0%	NMF	4.0%	3.8%	3.8%	4.2%	4.4%	3.9%	*3.0%*	*3.0%*	*3.5%*
All Div'ds to Net Prof							NMF	63%	NMF	60%	64%	67%	64%	62%	60%	*61%*	*61%*	*60%*

CAPITAL STRUCTURE as of 9/30/24
Total Debt $13614.5 mill. **Due in 5 Yrs** $4536 mill.
LT Debt $12086.3 mill. **LT Interest** $505 mill.
(Interest cov. earned: 5.5x) (54% of Cap'l)

Leases, Uncapitalized Annual rentals $9.6 mill.
Pension Assets-12/23 $1.4 bill. **Oblig.** $1.4 bill.

Common Stock 466,778,943 shs.
as of 10/22/24

MARKET CAP: $17.8 billion (Large Cap)

CURRENT POSITION ($MILL.)	2022	2023	9/30/24
Cash Assets	40.8	2245.4	126.2
Other	2543.5	2254.0	1489.8
Current Assets	2584.3	4499.4	1616.0
Accts Payable	899.5	749.4	614.6
Debt Due	1791.9	3072.4	1528.2
Other	1969.1	1443.3	1342.7
Current Liab.	4660.5	5265.1	3485.5
Fix. Chg. Cov.	255%	225%	445%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '21-'23 to '27-'29
Revenues	-3.5%	-1.5%	*5.5%*
"Cash Flow"	1.0%	6.5%	*5.5%*
Earnings	1.0%	10.5%	*9.5%*
Dividends	--	6.0%	*4.5%*
Book Value	-2.0%	3.5%	*5.0%*

Calendar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2022	1873	1183	1089	1704	5850.6
2023	1966	1090	1027	1422	5505.4
2024	1706	1085	1076	*1983*	*5850*
2025	*1840*	*1170*	*1160*	*2130*	*6300*
2026	*1970*	*1255*	*1245*	*2280*	*6750*

Calendar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2022	.75	.12	.10	.50	1.47
2023	.77	.11	.19	.53	1.60
2024	.85	.21	.20	*.49*	*1.75*
2025	*.85*	*.25*	*.20*	*.55*	*1.85*
2026	*.85*	*.30*	*.20*	*.65*	*2.00*

Calendar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	.22	.22	.22	.22	.88
2022	.235	.235	.235	.235	.94
2023	.25	.25	.25	.25	1.00
2024	.265	.265	.265	.265	1.06
2025	.28				

BUSINESS: NiSource Inc. is a holding company for Northern Indiana Public Service Company (NIPSCO), which supplies electricity and gas to the northern third of Indiana. Customers: 488,833 electric in Indiana, 3,200,000 gas in Indiana, Ohio, Pennsylvania, Kentucky, Virginia, Maryland, through its Columbia subsidiaries. Revenue breakdown, 2023: electrical, 32%; gas, 67%; other, less than 1%. Generating capacity, coal, 69.4%; purchased & other, 30.6%. 2023 reported depreciation rates: 3.5% electric, 2.4% gas. Has 7,364 employees. Chairman: Richard L. Thompson. President & Chief Executive Officer: Lloyd Yates. Incorporated: Indiana. Address: 801 East 86th Avenue, Merrillville, Indiana 46410. Telephone: 877-647-5990. Internet: www.nisource.com.

NiSource likely posted good results in 2024. (Note: the company was scheduled to report its fourth-quarter numbers as we went to press with this Issue.) Earnings per share probably advanced upwards of 9% in the year. This follows a cycle of heavy capital investments over the past few years, that the company is now earning returns on. NiSource is positioned across the mid-Atlantic and mid-West regions of the United States, and much of its operating areas have experienced strong growth, particularly from new data centers and industrial hubs. The utility may have invested as much as $2.5 billion in 2024 on projects including infrastructure hardening and clean energy programs. In addition to some regulatory success with rate cases, the utility is also enjoying wider fuel margins, bolstering profits, although higher depreciation and interest expenses have offset this to a degree. The company's good performance and strong positioning have led to a roughly 50% increase in its stock price over the past year, as investors see the utility as an increasingly attractive safe haven for funds.

The year ahead may see growth slow slightly. We've raised our 2025 earnings target by $0.05 per share, to $1.85, owing to good fundamental conditions and ongoing net-plant expansion. However, an uptick in volatility from new economic policies could bring about some near-term headwinds as businesses readjust to the emerging regulatory environment. We expect the utility will remain fairly aggressive through the current capital investment cycle while growing its rate base.

Over the long run we expect fairly steady growth. Rate-base growth is likely to follow a high-single-digit trajectory, in line with other associated metrics, including net plant and earnings per share. The company's transition away from coal and investment in clean energy and infrastructure hardening should provide a substantial growth ramp to late decade.

The shares have much of the gains we foresee already baked into the price. The stock offers below-average 3- to 5-year appreciation potential. We think there are more appealing selections out there, though the issue may interest conservative accounts.

Earl B. Humes *February 21, 2025*

(A) Dil. EPS. Excl. gains (losses) on disc. ops.: '08, ($1.14); '15, (30¢); '18, ($1.48). Next egs. report due early May. Qtl'y egs. may not sum to total due to rounding.
(B) Div'ds historically paid in mid-Feb., May, Aug., Nov. ■ Div'd reinv. avail.
(C) Incl. intang in '23: $1485.9 million, $3.33/sh.
(D) In mill.
(E) Spun off Columbia Pipeline Group (7/15)

Company's Financial Strength	A
Stock's Price Stability	95
Price Growth Persistence	25
Earnings Predictability	70

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N.W. NATURAL NYSE-NWN

RECENT PRICE 40.00 | P/E RATIO 14.1 (Trailing: 18.9 Median: 24.0) | RELATIVE P/E RATIO 0.77 | DIV'D YLD 4.9% | VALUE LINE

TIMELINESS 4 Lowered 11/29/24
SAFETY 2 Raised 2/23/24
TECHNICAL 2 Raised 1/3/25
BETA .90 (1.00 = Market)

18-Month Target Price Range

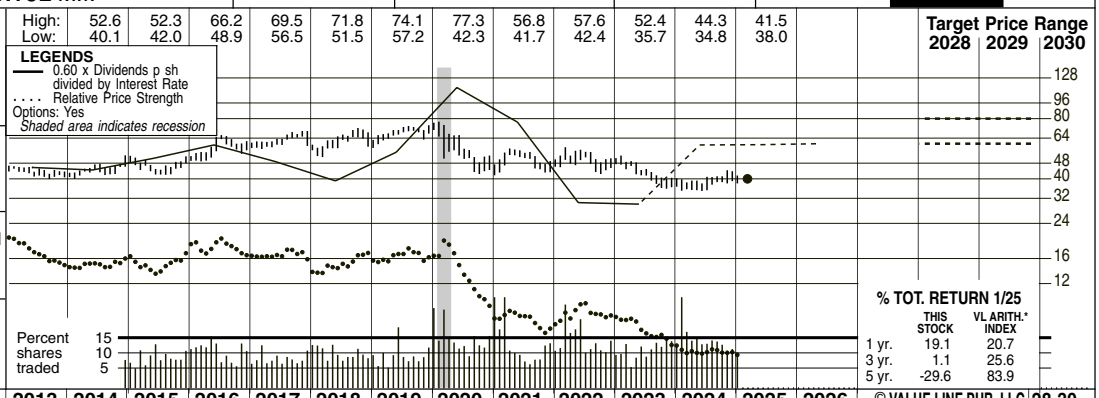
Low-High	Midpoint (% to Mid)
$27-$47	$37 (-10%)

2028-30 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	80	(+100%)	*22%*
Low	60	(+50%)	*14%*

Institutional Decisions

	1Q2024	2Q2024	3Q2024
to Buy	131	132	119
to Sell	105	104	118
Hld's(000)	28777	29331	37328



	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	© VALUE LINE PUB. LLC	28-30
High:	52.6	52.3	66.2	69.5	71.8	74.1	77.3	56.8	57.6	52.4	44.3	41.5								
Low:	40.1	42.0	48.9	56.5	51.5	57.2	42.3	41.7	42.4	35.7	34.8	38.0								
	38.17	30.56	31.72	27.14	28.02	27.64	26.39	23.61	26.52	24.45	24.49	25.29	27.64	29.20	31.82	*28.05*	*29.20*	*30.20*	Revenues per sh	*30.00*
	5.20	5.18	5.00	4.94	5.04	5.05	4.91	4.93	1.04	5.28	5.15	5.69	6.17	5.71	5.83	*5.45*	*6.50*	*6.65*	"Cash Flow" per sh	*7.45*
	2.83	2.73	2.39	2.22	2.24	2.16	1.96	2.12	d1.94	2.33	2.19	2.30	2.56	2.54	2.59	*2.30*	*3.00*	*3.10*	Earnings per sh [A]	*3.45*
	1.60	1.68	1.75	1.79	1.83	1.85	1.86	1.87	1.88	1.89	1.90	1.91	1.92	1.93	1.94	1.95	*1.96*	*1.97*	Div'ds Decl'd per sh [B]■	*2.00*
	5.09	9.35	3.76	4.91	5.13	4.40	4.37	4.87	7.43	7.43	7.95	9.18	9.49	9.53	8.70	*9.75*	*9.50*	*10.00*	Cap'l Spending per sh	*11.50*
	24.88	26.08	26.70	27.23	27.77	28.12	28.47	29.71	25.85	26.41	28.42	29.05	30.04	33.09	34.12	*36.50*	*37.60*	*40.30*	Book Value per sh [D]	*44.20*
	26.53	26.58	26.76	26.92	27.08	27.28	27.43	28.63	28.74	28.88	30.47	30.59	31.13	35.53	37.63	*41.00*	*43.00*	*45.00*	Common Shs Outst'g [C]	*50.00*
	15.2	17.0	19.0	21.1	19.4	20.7	23.7	26.9	- -	26.6	30.9	25.0	19.5	19.6	16.6	*16.8*	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	*20.0*
	1.01	1.08	1.19	1.34	1.09	1.09	1.19	1.41	- -	1.44	1.65	1.28	1.05	1.13	.92	*.93*			Relative P/E Ratio	*1.10*
	3.7%	3.6%	3.9%	3.8%	4.2%	4.1%	4.0%	3.3%	3.0%	3.0%	2.8%	3.3%	3.8%	3.9%	4.5%	5.1%			Avg Ann'l Div'd Yield	*2.9%*
	723.8	676.0	762.2	706.1	746.4	773.7	860.4	1037.4	1197.5	*1150*	*1255*	*1360*							Revenues ($mill)	*1500*
	53.7	58.9	d55.6	67.3	65.3	70.3	78.7	86.3	93.9	*95.0*	*130*	*140*							Net Profit ($mill)	*175*
	40.0%	40.9%	- -	26.4%	16.2%	23.1%	25.8%	25.2%	25.6%	*25.0%*	*25.0%*	*25.0%*							Income Tax Rate	*25.0%*
	7.4%	8.7%	NMF	9.5%	8.8%	9.1%	9.1%	8.3%	7.8%	*8.2%*	*10.3%*	*10.3%*							Net Profit Margin	*11.5%*
	42.5%	44.4%	47.9%	48.1%	48.2%	49.2%	52.8%	51.5%	52.6%	*52.5%*	*55.0%*	*55.0%*							Long-Term Debt Ratio	*55.0%*
	57.5%	55.6%	52.1%	51.9%	51.8%	50.8%	47.2%	48.5%	47.4%	*47.5%*	*45.0%*	*45.0%*							Common Equity Ratio	*45.0%*
	1357.7	1529.8	1426.0	1468.9	1672.0	1748.8	1979.7	2421.6	2709.3	*3150*	*3600*	*4030*							Total Capital ($mill)	*4915*
	2182.7	2260.9	2255.0	2421.4	2438.9	2654.8	2871.4	3114.4	3358.1	*3750*	*4150*	*4535*							Net Plant ($mill)	*5320*
	5.5%	5.1%	NMF	5.8%	5.2%	5.2%	5.1%	4.7%	4.9%	*3.0%*	*3.5%*	*3.5%*							Return on Total Cap'l	*3.5%*
	6.9%	6.9%	NMF	8.8%	7.5%	7.9%	8.4%	7.3%	7.3%	*6.5%*	*8.0%*	*7.5%*							Return on Shr. Equity	*8.0%*
	6.9%	6.9%	NMF	8.8%	7.5%	7.9%	8.4%	7.3%	7.3%	*6.5%*	*8.0%*	*7.5%*							Return on Com Equity	*8.0%*
	.6%	.9%	NMF	2.1%	1.4%	1.7%	2.4%	2.0%	2.1%	*1.0%*	*2.5%*	*2.5%*							Retained to Com Eq	*2.5%*
	92%	87%	NMF	76%	82%	79%	71%	73%	72%	*85%*	*65%*	*64%*							All Div'ds to Net Prof	*58%%*

CAPITAL STRUCTURE as of 9/30/24
Total Debt $1736 mill. **Due in 5 Yrs** $1395 mill.
LT Debt $1555 mill. **LT Interest** $80 mill.

(Total interest coverage: 5.0x)

Pension Assets-12/23 $283.0 mill.
Oblig. $425.5 mill.

Pfd Stock None

Common Stock 40,132,048 shares
as of 10/31/24

MARKET CAP $1.6 billion (Small Cap)

CURRENT POSITION ($MILL.)	2022	2023	9/30/24
Cash Assets	29.3	32.9	35.0
Other	714.9	568.5	373.9
Current Assets	744.2	601.4	408.9
Accts Payable	180.7	145.4	96.3
Debt Due	348.9	240.7	180.6
Other	369.1	310.8	290.5
Current Liab.	898.7	696.9	567.4
Fix. Chg. Cov.	320%	240%	350%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '21-'23 to '28-'30
Revenues	- -	3.5%	*4.5%*
"Cash Flow"	1.5%	9.5%	*5.0%*
Earnings	1.0%	25.0%	*6.5%*
Dividends	1.0%	.5%	*.5%*
Book Value	2.0%	3.5%	*4.0%*

Calendar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2022	350.3	195.0	116.8	375.3	1037.4
2023	462.4	237.9	141.5	355.7	1197.5
2024	433.5	211.7	136.9	*367.9*	*1150*
2025	*475*	*230*	*150*	*400*	*1255*
2026	*515*	*250*	*165*	*430*	*1360*

Calendar	EARNINGS PER SHARE [A] Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2022	1.80	.05	d.56	1.36	2.54
2023	2.01	.03	d.65	1.21	2.59
2024	1.69	d.07	d.71	*1.39*	*2.30*
2025	*2.10*	*.05*	*d.60*	*1.45*	*3.00*
2026	*2.15*	*.05*	*d.65*	*1.55*	*3.10*

Calendar	QUARTERLY DIVIDENDS PAID [B] ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	.48	.48	.48	.483	1.92
2022	.483	.483	.483	.485	1.93
2023	.485	.485	.485	.488	1.94
2024	.488	.488	.488	.49	1.95
2025	.49				

BUSINESS: Northwest Natural Holding Co. distributes natural gas to 1,000 communities, 795,000 customers, in Oregon (88% of customers) and in southwest Washington state. Principal cities served: Portland and Eugene, OR; Vancouver, WA. Service area population: 3.7 mill. (77% in OR). Company buys gas supply from Canadian and U.S. producers; has transportation rights on Northwest Pipeline system. Owns local underground storage. Rev. breakdown: residential, 38%; commercial, 23%; industrial, gas transportation, 39%. Employs 1,380. BlackRock Inc. owns 17.6% of shares; Vanguard, 12.4%; Off./Dir., .84% (4/24 proxy). CEO: David H. Anderson. Inc.: Oregon. Address: 220 NW 2nd Ave., Portland, OR 97209. Tel.: 503-226-4211. Internet: www.nwnatural.com.

Northwest Natural probably had a weak performance in 2024. (Note: The company was scheduled to release its full-year results as we went to press with this Issue.) Fourth-quarter earnings probably compared favorably versus years past, driven by the resolution of an Oregon gas utility rate case in October. The company's revenue requirement increased $93 million as a result. Unfortunately, regulators did not approve recovery for $14 million of investments in line extensions, which were previously allowed, and will result in a noncash disallowance charge in the quarter. A new rate case was filed for about half as much, expected to take effect in late 2025. Customer expansion and various auxilliary water and waste-water business additions completed this year probably contributed to some growth. However, earnings for the full year likely decreased to around $2.30 per share, after having plataued at roughly $2.55 for the past three years. This is in large part due to regulatory lag that was partially resolved in the recent rate case, as well as specific non-recurring other income and taxes.

We expect earnings to rebound in the year ahead. The bottom line should find support from a mix of factors. The company has diversified market exposure to various geographies across natural gas, water, and renewables, which improves its ability to capitalize on several growth opportunities. Furthermore, its positioning in strong geographies adds to this expansion potential with single-family housing permits in the Portland area up 13% and relatively low unemployment lending strong underlying economic trends. We think the company could achieve earnings of $3.00 per share in 2025.

Long-term growth will likely be in the high-single digits. The company has room for further expansion through system buildouts, maintenance and innovation associated with an increasing focus on climate resiliency, which should help to drive investment out to late decade.

The stock offers solid recovery potential out three to five years, and boasts a high dividend yield. However, recent weakness makes this a below-average pick for year-ahead performance (Timeliness 4).

Earl B. Humes *February 21, 2025*

(A) Diluted earnings per share. Excludes nonrecurring items: '08, ($0.03); '09, $0.06; May not sum due to rounding. Next earnings report due in early May.
(B) Dividends historically paid in mid-February, May, August, and November.
■ Dividend reinvestment plan available.
(C) In millions.
(D) Includes intangibles. In 2023: $163 million, $4.33/share.

Company's Financial Strength	A
Stock's Price Stability	85
Price Growth Persistence	20
Earnings Predictability	20

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ONE GAS, INC. NYSE-OGS

RECENT PRICE 70.20 | P/E RATIO 16.9 (Trailing: 18.3 Median: 21.0) | RELATIVE P/E RATIO 0.92 | DIV'D YLD 3.8% | VALUE LINE

TIMELINESS 4 Lowered 11/22/24
SAFETY 2 New 6/2/17
TECHNICAL 3 Lowered 2/21/25
BETA .85 (1.00 = Market)

18-Month Target Price Range
Low-High: $44-$83 | Midpoint (% to Mid): $64 (-10%)

2028-30 PROJECTIONS

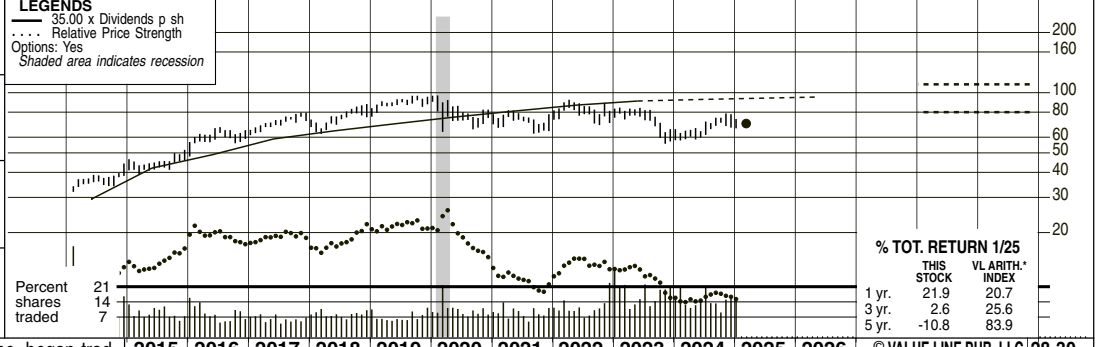
	Price	Gain	Ann'l Total Return
High	110	(+55%)	*15%*
Low	80	(+15%)	*7%*

Institutional Decisions

	1Q2024	2Q2024	3Q2024
to Buy	170	143	152
to Sell	147	160	146
Hld's(000)	51905	53086	62020

	44.3	51.8	67.4	79.5	87.8	96.7	97.0	81.9	92.3	84.3	78.9	73.9
High:												
Low:	31.9	38.9	48.0	61.4	62.2	75.8	63.7	62.5	68.9	55.5	57.7	66.4

LEGENDS
35.00 x Dividends p sh
Relative Price Strength
Options: Yes
Shaded area indicates recession



% TOT. RETURN 1/25

	THIS STOCK	VL ARITH.* INDEX
1 yr.	21.9	20.7
3 yr.	2.6	25.6
5 yr.	-10.8	83.9

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	© VALUE LINE PUB. LLC	28-30
	29.62	27.30	29.43	31.08	31.32	28.78	33.72	46.58	41.95	*36.65*	*38.95*	*41.25*	Revenues per sh	*67.55*
	4.82	5.43	5.96	6.32	6.96	7.36	7.71	8.13	9.04	*9.75*	*11.00*	*12.15*	"Cash Flow" per sh	*15.55*
	2.24	2.65	3.02	3.25	3.51	3.68	3.85	4.08	4.14	*3.85*	*4.25*	*4.50*	Earnings per sh A	*5.25*
	1.20	1.40	1.68	1.84	2.00	2.16	2.32	2.48	2.60	2.64	*2.68*	*2.72*	Div'ds Decl'd per sh B■	*2.90*
	5.63	5.91	6.81	7.50	7.91	8.87	9.23	11.01	11.79	*12.10*	*12.30*	*12.45*	Cap'l Spending per sh	*12.75*
	35.24	36.12	37.47	38.86	40.35	42.01	43.81	46.69	48.91	*51.75*	*55.95*	*59.25*	Book Value per sh	*69.45*
	52.26	52.28	52.31	52.57	52.77	53.17	53.63	55.35	56.55	*56.50*	*56.50*	*56.50*	Common Shs Outst'g C	*57.00*
	19.8	22.7	23.5	23.1	25.3	21.7	18.9	19.9	18.0	*17.3*	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	*18.0*
	1.00	1.19	1.18	1.25	1.35	1.11	1.02	1.15	1.01	*.96*			Relative P/E Ratio	*1.00*
	2.7%	2.3%	2.4%	2.5%	2.3%	2.7%	3.2%	3.1%	3.5%	4.0%			Avg Ann'l Div'd Yield	*3.1%*
	1547.7	1427.2	1539.6	1633.7	1652.7	1530.3	1808.6	2578.0	2372.0	*2070*	*2200*	*2330*	Revenues ($mill)	*3850*
	119.0	140.1	159.9	172.2	186.7	196.4	206.4	221.7	231.2	*220*	*240*	*255*	Net Profit ($mill)	*300*
	38.0%	37.8%	36.4%	23.7%	18.7%	17.5%	16.3%	17.3%	14.9%	*16.5%*	*17.0%*	*17.5%*	Income Tax Rate	*20.0%*
	7.7%	9.8%	10.4%	10.5%	11.3%	12.8%	11.4%	8.6%	9.7%	*10.6%*	*10.9%*	*10.9%*	Net Profit Margin	*7.8%*
	39.5%	38.7%	37.8%	38.6%	37.7%	41.5%	61.1%	50.7%	43.8%	*46.0%*	*45.0%*	*45.0%*	Long-Term Debt Ratio	*45.0%*
	60.5%	61.3%	62.2%	61.4%	62.3%	58.5%	38.9%	49.3%	56.2%	*54.0%*	*55.0%*	*55.0%*	Common Equity Ratio	*55.0%*
	3042.9	3080.7	3153.5	3328.1	3415.5	3815.7	6032.9	5246.2	4926.3	*5415*	*5750*	*6085*	Total Capital ($mill)	*7200*
	3511.9	3731.6	4007.6	4283.7	4565.2	4867.1	5190.8	5628.8	6135.2	*6650*	*7025*	*7400*	Net Plant ($mill)	*8500*
	4.7%	5.2%	5.8%	5.9%	6.4%	6.0%	3.9%	5.0%	5.9%	*5.5%*	*5.5%*	*5.5%*	Return on Total Cap'l	*5.5%*
	6.5%	7.4%	8.2%	8.4%	8.8%	8.8%	8.8%	8.6%	8.4%	*7.5%*	*7.5%*	*7.5%*	Return on Shr. Equity	*7.5%*
	6.5%	7.4%	8.2%	8.4%	8.8%	8.8%	8.8%	8.6%	8.4%	*7.5%*	*7.5%*	*7.5%*	Return on Com Equity	*7.5%*
	3.1%	3.5%	3.7%	3.7%	3.8%	3.7%	3.5%	3.4%	3.2%	*2.5%*	*3.0%*	*3.0%*	Retained to Com Eq	*3.5%*
	53%	52%	55%	56%	56%	58%	60%	60%	62%	*68%*	*63%*	*60%*	All Div'ds to Net Prof	*55%*

The shares of ONE Gas, Inc. began trading "regular-way" on the New York Stock Exchange on February 3, 2014. That happened as a result of the separation of ONEOK's natural gas distribution operation. Regarding the details of the spinoff, on January 31, 2014, ONEOK distributed one share of OGS common stock for every four shares of ONEOK common stock held by ONEOK shareholders of record as of the close of business on January 21. It should be mentioned that ONEOK did not retain any ownership interest in the new company.

CAPITAL STRUCTURE as of 9/30/24
Total Debt $3365.3 mill. **Due in 5 Yrs** $890.0 mill.
LT Debt $2384.9 mill. **LT Interest** $120.0 mill.
(LT interest earned: 3.4x; total interest coverage: 3.4x)
Leases, Uncapitalized Annual rentals $6.7 mill.
Pfd Stock None
Pension Assets-12/23 $977.0 mill. **Oblig.** $962.1 mill.
Common Stock 56,655,256 shs.
as of 10/28/24
MARKET CAP: $4.0 billion (Mid Cap)

CURRENT POSITION ($MILL.)	2022	2023	9/30/24
Cash Assets	9.7	18.8	18.8
Other	1207.9	746.4	671.7
Current Assets	1217.6	765.2	690.5
Accts Payable	360.5	278.1	146.8
Debt Due	572.7	888.9	980.4
Other	256.2	310.2	260.4
Current Liab.	1189.4	1477.2	1387.6
Fix. Chg. Cov.	540%	390%	405%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '21-'23 to '28-'30
Revenues	- -	7.0%	*7.5%*
"Cash Flow"	- -	7.0%	*9.5%*
Earnings	- -	6.0%	*4.0%*
Dividends	- -	8.5%	*2.5%*
Book Value	- -	4.5%	*6.0%*

Calendar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2022	971.5	428.9	359.4	818.2	2578.0
2023	1032.1	398.1	335.8	606.0	2372.0
2024	758.3	354.1	340.4	*617.2*	*2070*
2025	*800*	*375*	*350*	*675*	*2200*
2026	*825*	*400*	*380*	*725*	*2330*

Calendar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2022	1.83	.59	.44	1.23	4.08
2023	1.84	.58	.45	1.27	4.14
2024	1.75	.48	.34	*1.28*	*3.85*
2025	*1.85*	*.58*	*.44*	*1.38*	*4.25*
2026	*1.94*	*.63*	*.48*	*1.45*	*4.50*

Calendar	QUARTERLY DIVIDENDS PAID B■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	.58	.58	.58	.58	2.32
2022	.62	.62	.62	.62	2.48
2023	.65	.65	.65	.65	2.60
2024	.66	.66	.66	.66	2.64
2025	.67				

BUSINESS: ONE Gas, Inc. provides natural gas distribution services to more than two million customers. There are three divisions: Oklahoma Natural Gas, Kansas Gas Service, and Texas Gas Service. The company purchased 160 Bcf of natural gas supply in 2023, compared to 165 Bcf in 2022. Total volumes delivered by customer (fiscal 2023): transportation, 59.3%; residential, 29.7%; commercial & industrial, 10.6%; other, .4%. ONE Gas has around 3,900 employees. BlackRock owns 14.5% of common stock; The Vanguard Group, 11.6%; American Century Investment, 7.5%; officers and directors, 1.5% (4/24 Proxy). CEO: Robert S. McAnnally. Incorporated: Oklahoma. Address: 15 East Fifth Street, Tulsa, Oklahoma 74103. Tel.: 918-947-7000. Internet: www.onegas.com.

Earnings for ONE Gas likely took a turn for the worse in 2024. (Please be aware that fourth-quarter results were not released to the public when this report went to press.) Recall that during the first nine months, the bottom line retreated 10.5%, to $2.57 per share, relative to the $2.87 tally that was posted for the same period in 2023. This stemmed partially from higher employee-related costs, given planned investments in the company's workforce and ongoing in-sourcing efforts. Depreciation & amortization expense climbed, too, reflecting additional capital investments. Furthermore, sales volumes decreased and interest charges rose. So, it appears that earnings per share finished in the vicinity of $3.85 for the full year. That would mark a 7% decline from 2023's $4.14 total.

We believe that a recovery is possible in 2025, however. New rates should be one contributing factor. Benefits arising from additional expansion of the customer base ought to lift results, as well. Operating expenses (including those already mentioned) stand to continue to mount, but that is to be expected as the company grows. Consequently, profits might advance around 10%, to $4.25 a share. Regarding 2026, we look for the bottom line to increase another 6% or so, to $4.50 per share, assuming that business conditions cooperate.

The quarterly dividend was raised by one cent, to $0.67 a share. ONE Gas states that it intends to keep the average annual dividend growth rate between 1% and 2% through fiscal 2029. We think that significantly slower increase, compared to previous years, is partially because of climbing operating costs. In any case, the payout ratio out to the beginning of the next decade should be reasonable, in the neighborhood of 55%.

What about OGS shares? The dividend yield is decent when measured against those of other stocks in *Value Line's* Natural Gas Utility category. But, at the recent quotation, capital appreciation potential over the 3- to 5-year horizon is nothing to write home about. Meanwhile, the equity is pegged to trail the market for the next six to 12 months (Timeliness rank 4: Below Average).

Frederick L. Harris, III February 21, 2025

(A) Diluted EPS. Excludes nonrecurring gain: 2017, $0.06. Next earnings report due early May. Quarterly EPS figures for 2022 don't equal total due to rounding.
(B) Dividends historically paid in early March, June, Sept., and Dec. ■ Dividend reinvestment plan. Direct stock purchase plan.
(C) In millions.

Company's Financial Strength	B++
Stock's Price Stability	85
Price Growth Persistence	40
Earnings Predictability	100

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SOUTHWEST GAS NYSE-SWX

RECENT PRICE 76.38 | P/E RATIO 19.7 (Trailing: 30.7 Median: 21.0) | RELATIVE P/E RATIO 1.07 | DIV'D YLD 3.2% | VALUE LINE

TIMELINESS — Suspended 11/17/23
SAFETY 2 Raised 2/23/24
TECHNICAL — Suspended 11/17/23
BETA .95 (1.00 = Market)

18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$50-$90	$70 (-10%)

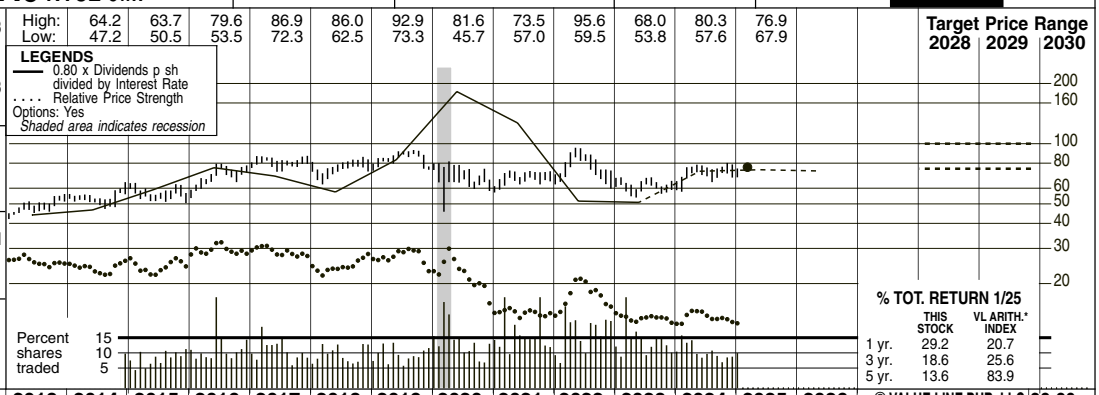
2028-30 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	100	(+30%)	*10%*
Low	75	(Nil)	*3%*

Institutional Decisions

	1Q2024	2Q2024	3Q2024
to Buy	122	141	144
to Sell	149	131	138
Hld's(000)	65977	66812	73232

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	© VALUE LINE PUB. LLC	28-30
High:	64.2	63.7	79.6	86.9	86.0	92.9	81.6	73.5	95.6	68.0	80.3	76.9								
Low:	47.2	50.5	53.5	72.3	62.5	73.3	45.7	57.0	59.5	53.8	57.6	67.9								
	42.00	40.18	41.07	41.77	42.08	45.61	52.00	51.82	53.00	54.31	56.72	57.68	60.91	73.90	75.93	*71.55*	*73.95*	*78.75*	Revenues per sh	*84.00*
	6.16	6.46	6.81	7.73	8.24	8.47	8.62	9.29	8.83	8.14	9.40	9.87	9.46	3.98	8.27	*8.75*	*9.85*	*10.51*	"Cash Flow" per sh	*11.85*
	1.94	2.27	2.43	2.86	3.11	3.01	2.92	3.18	3.62	3.68	3.94	4.14	3.39	d3.10	2.13	*2.80*	*3.60*	*4.00*	Earnings per sh [A]	*4.85*
	.95	1.00	1.06	1.18	1.32	1.46	1.62	1.80	1.98	2.08	2.18	2.28	2.38	2.46	2.48	2.48	*2.48*	*2.48*	Div'ds Decl'd per sh [B■†]	*3.00*
	4.81	4.73	8.29	8.57	7.86	8.53	10.30	11.15	12.97	14.44	17.06	14.43	11.84	12.80	12.19	*11.80*	*12.50*	*13.50*	Cap'l Spending per sh	*14.50*
	24.44	25.62	26.66	28.35	30.47	31.95	33.61	35.03	37.74	42.47	45.56	46.77	48.89	45.57	46.25	*51.70*	*54.25*	*55.50*	Book Value per sh	*58.65*
	45.09	45.56	45.96	46.15	46.36	46.52	47.38	47.48	48.09	53.03	55.01	57.19	60.42	67.12	71.56	*72.00*	*73.00*	*73.00*	Common Shs Outst'g [C]	*75.00*
	12.2	14.0	15.7	15.0	15.8	17.9	19.4	21.6	22.2	20.6	21.3	16.8	19.9	- -	29.0	*25.5*	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	*18.0*
	.81	.89	.98	.95	.89	.94	.98	1.13	1.12	1.11	1.13	.86	1.08	- -	1.61	*1.42*			Relative P/E Ratio	*1.00*
	4.0%	3.2%	2.8%	2.8%	2.7%	2.7%	2.9%	2.6%	2.5%	2.7%	2.6%	3.3%	3.5%	3.2%	4.0%	3.5%			Avg Ann'l Div'd Yield	*3.4%*
	2463.6	2460.5	2548.8	2880.0	3119.9	3298.9	3680.5	4960.0	5434.0	*5150*	*5400*	*5750*	Revenues ($mill)	*6300*
	138.3	152.0	173.8	182.3	213.9	232.3	200.8	d203.3	150.9	*200*	*265*	*290*	Net Profit ($mill)	*365*
	36.4%	33.9%	32.8%	25.3%	20.5%	21.6%	16.1%	- -	21.2%	*21.0%*	*21.0%*	*21.0%*	Income Tax Rate	*21.0%*
	5.6%	6.2%	6.8%	6.3%	6.9%	7.0%	5.5%	NMF	2.8%	*3.9%*	*4.9%*	*5.1%*	Net Profit Margin	*5.8%*
	49.3%	48.2%	49.8%	48.3%	47.9%	50.5%	58.2%	59.0%	58.2%	*55.0%*	*55.0%*	*55.0%*	Long-Term Debt Ratio	*56.0%*
	50.7%	51.8%	50.2%	51.7%	52.1%	49.5%	41.8%	41.0%	41.8%	*45.0%*	*45.0%*	*45.0%*	Common Equity Ratio	*44.0%*
	3143.5	3213.5	3613.3	4359.3	4806.4	5407.2	7069.5	7462.1	7919.9	*8200*	*8800*	*9000*	Total Capital ($mill)	*10000*
	3891.1	4132.0	4523.7	5093.2	5685.2	6176.1	7594.0	7024.5	7518.2	*8100*	*8700*	*9275*	Net Plant ($mill)	*10450*
	5.5%	5.8%	5.8%	5.2%	5.4%	5.3%	3.4%	NMF	3.8%	*2.5%*	*3.0%*	*3.0%*	Return on Total Cap'l	*3.5%*
	8.7%	9.1%	9.6%	8.1%	8.5%	8.7%	6.8%	NMF	4.6%	*5.5%*	*6.5%*	*7.0%*	Return on Shr. Equity	*8.5%*
	8.7%	9.1%	9.6%	8.1%	8.5%	8.7%	6.8%	NMF	4.6%	*5.5%*	*6.5%*	*7.0%*	Return on Com Equity	*8.5%*
	4.0%	4.1%	4.5%	3.6%	3.9%	4.0%	2.1%	NMF	NMF	*.5%*	*2.0%*	*2.5%*	Retained to Com Eq	*3.0%*
	54%	55%	53%	55%	54%	54%	69%	NMF	116%	*89%*	*70%*	*62%*	All Div'ds to Net Prof	*62%*



CAPITAL STRUCTURE as of 9/30/24
Total Debt $5045.1 mill. **Due in 5 Yrs** $1008 mill.
LT Debt $4382.1 mill. **LT Interest** $300 mill.
(Total interest coverage: 2.6x) (55% of Cap'l)

Leases, Uncapitalized Annual rentals $24.9 mill.
Pension Assets-12/23 $1202.0 mill.
Oblig. $1352.2 mill.

Pfd Stock None

Common Stock 71,743,666 shs.
as of 10/25/24

MARKET CAP: $5.5 billion (Mid Cap)

CURRENT POSITION ($MILL.)	2022	2023	9/30/24
Cash Assets	123.1	106.5	456.6
Other	3584.6	1774.6	998.8
Current Assets	3707.7	1881.1	1455.4
Accts Payable	662.1	346.9	227.0
Debt Due	1587.4	671.1	663.0
Other	1173.5	666.8	812.7
Current Liab.	1173.5	1684.8	1702.7
Fix. Chg. Cov.	265%	145%	225%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '21-'23 to '28-'30
Revenues	5.5%	6.5%	*6.0%*
"Cash Flow"	-3.0%	-7.0%	*8.5%*
Earnings	- -	- -	*10.0%*
Dividends	6.5%	3.5%	*5.5%*
Book Value	4.5%	2.0%	*7.5%*

Calendar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2022	1267.4	1146.1	1125.6	1420.9	4960.0
2023	1603.3	1293.6	1169.5	1387.6	5454.0
2024	1581.0	1182.2	1079.2	*1307.6*	*5150*
2025	*1660*	*1240*	*1225*	*1275*	*5400*
2026	*1770*	*1320*	*1305*	*1355*	*5750*

Calendar	EARNINGS PER SHARE [A D] Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2022	1.58	d.10	d.18	d4.18	d3.10
2023	.67	.40	.04	1.02	2.13
2024	1.22	.25	- -	*1.33*	*2.80*
2025	*1.75*	*.65*	*.15*	*1.05*	*3.60*
2026	*1.95*	*.70*	*.15*	*1.20*	*4.00*

Calendar	QUARTERLY DIVIDENDS PAID [B■†] Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	.570	.595	.595	.595	2.36
2022	.595	.62	.62	.62	2.46
2023	.62	.62	.62	.62	2.48
2024	.62	.62	.62	.62	2.48
2025	.62				

BUSINESS: Southwest Gas Holdings, Inc. is the parent holding company of Southwest Gas. Centuri Group spun-off 4/22/24. Southwest Gas is a regulated gas distributor serving 2.2 million customers in Arizona, Nevada, and California. 2023 margin mix: residential 68%; small commercial, 20%; large commercial and industrial, 8%; transportation, 4%. Total throughput: 2.2 billion therms. Southwest has 2,371 employees; Centuri 12,572. Off. & dir. own .4% of common stock; Carl C. Icahn, 15.4%; BlackRock, 13.0%; The Vanguard Group, 10.1%; (3/24 Proxy). Chairman: Michael J. Melarkey. Pres. & CEO: Karen S. Haller. Inc.: DE. Addr.: 8360 S. Durango Drive, P.O. Box 98510 Las Vegas, Nevada 89193. Telephone: 702-876-7237. Internet: www.swgas.com.

Southwest Gas Holdings' performance has been affected by significant corporate restructuring over the past two years. In early 2023 the company sold its MountainWest Pipeline business, then spun off Centuri Group's infrastructure services operation in an early 2024 initial public offering, although it still retains a significant portion of the newly issued stock. These changes have contributed to many unique charges and uneven results over the past few years. All of this is in the aim of transitioning into a fully regulated natural gas utility. We think this strategy will likely enhance operating efficiency and maximize shareholder value over the long run. The sale of these auxiliary businesses has also helped to provide capital to invest and optimize the capital structure.

The pure-play utility likely had a good showing for 2024. We expect the company reported net income of at least $200 million, though management's more optimistic guidance range calls for this figure in the range of roughly $235 million to $245 million. Capital expenditures likely totaled $850 million.

Southwest has a fairly bright outlook for the years ahead. One key strength is in the company's strong geographic positioning. Southwest's operating footprint includes some of the fastest growing regions in the country in Arizona and Nevada. These areas also offer good potential for semiconductor manufacturing and data centers. To help meet new and existing demand, management has a robust pipeline of capital investments and projects rate base growth of 10% per year. The company also operates in a more favorable regulatory environment with respect to rate case executions.

The stock appears to price in many of these good qualities. The equity has increased roughly 30% over the past year, significantly diminishing long-term upside potential at the recent quotation. The stock's dividend yield is above average, but many industry peers offer more appeal. Too, there is still significant uncertainties regarding the company's future performance as a stand-alone utility group. Ultimately, we think most investors will want to turn the page.

Earl B. Humes *February 21, 2025*

(A) Diluted earnings. Excl. nonrec. gains (losses): '22, 10¢. Next egs. report due early May. **(B)** Dividends historically paid early March, June, September, and December. ■† Div'd reinvestment and stock purchase plan avail. **(C)** In millions. **(D)** Totals may not sum due to rounding. **(E)** Rank suspended 11/17/2023 for spin-off of the Centuri Group.

Company's Financial Strength	A
Stock's Price Stability	80
Price Growth Persistence	25
Earnings Predictability	5

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SPIRE INC. NYSE-SR

RECENT PRICE **71.88** | P/E RATIO **18.2** (Trailing: 17.4 Median: 18.0) | RELATIVE P/E RATIO **0.99** | DIV'D YLD **4.4%** | **VALUE LINE**

TIMELINESS 3 Raised 2/14/25
SAFETY 2 Raised 6/20/03
TECHNICAL 3 Lowered 1/24/25
BETA .90 (1.00 = Market)

18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$53-$83	$68 (-5%)

2028-30 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	105	(+45%)	*13%*
Low	80	(+10%)	*7%*

Institutional Decisions

	1Q2024	2Q2024	3Q2024
to Buy	135	160	159
to Sell	134	108	130
Hld's(000)	48507	49797	57334

	2028	2029	2030
Target Price Range			

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	© VALUE LINE PUB. LLC	28-30
	85.49	77.83	71.48	49.90	31.10	37.68	45.59	33.68	36.07	38.78	38.30	35.96	43.24	41.88	50.12	44.94	*41.75*	*41.95*	Revenues per sh [A]	*47.90*
	4.56	4.11	4.62	4.58	3.12	3.87	6.15	6.16	6.54	7.55	7.12	5.25	9.09	8.44	8.60	8.92	*8.90*	*9.35*	"Cash Flow" per sh	*10.85*
	2.92	2.43	2.86	2.79	2.02	2.35	3.16	3.24	3.43	4.33	3.52	1.44	4.96	3.95	3.85	4.19	*3.95*	*4.15*	Earnings per sh [A B]	*5.25*
	1.53	1.57	1.61	1.66	1.70	1.76	1.84	1.96	2.10	2.25	2.37	2.49	2.60	2.74	2.88	3.02	*3.14*	*3.26*	Div'ds Decl'd per sh [C■]	*3.70*
	2.36	2.56	3.02	4.83	4.00	3.96	6.68	6.42	9.08	9.86	16.15	12.37	12.09	10.52	12.45	14.93	*13.15*	*13.25*	Cap'l Spending per sh	*12.75*
	23.32	24.02	25.56	26.67	32.00	34.93	36.30	38.73	41.26	44.51	45.14	44.19	46.74	49.08	50.29	51.83	*53.05*	*54.55*	Book Value per sh [D]	*57.80*
	22.17	22.29	22.43	22.55	32.70	43.18	43.36	45.65	48.26	50.67	50.97	51.60	51.70	52.50	53.20	57.70	*60.00*	*62.00*	Common Shs Outst'g [E]	*72.00*
	13.4	13.7	13.0	14.5	21.3	19.8	16.5	19.6	19.8	16.7	22.8	51.1	13.6	17.5	17.3	14.6	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	*17.5*
	.89	.87	.82	.92	1.20	1.04	.83	1.03	1.00	.90	1.21	2.62	.73	1.01	1.00	.76			Relative P/E Ratio	*.95*
	3.9%	4.7%	4.3%	4.1%	4.0%	3.8%	3.5%	3.1%	3.1%	3.1%	3.0%	3.4%	3.8%	4.0%	4.3%	4.9%			Avg Ann'l Div'd Yield	*4.0%*
							1976.4	1537.3	1740.7	1965.0	1952.4	1855.4	2235.5	2198.5	2666.3	2593.0	*2505*	*2600*	Revenues ($mill) [A]	*3450*
							136.9	144.2	161.6	214.2	184.6	88.6	271.7	220.8	217.5	250.9	*235*	*255*	Net Profit ($mill)	*380*
							31.2%	32.5%	32.4%	--	15.7%	12.3%	20.1%	21.1%	15.1%	19.0%	*19.0%*	*19.5%*	Income Tax Rate	*23.5%*
							6.9%	9.4%	9.3%	10.9%	9.5%	4.8%	12.2%	10.0%	8.2%	9.7%	*9.4%*	*9.8%*	Net Profit Margin	*11.0%*
							53.0%	50.9%	50.0%	45.7%	45.0%	49.0%	52.5%	51.2%	54.9%	53.4%	*53.0%*	*53.0%*	Long-Term Debt Ratio	*51.0%*
							47.0%	49.1%	50.0%	54.3%	49.7%	46.1%	43.2%	44.6%	41.3%	43.1%	*43.0%*	*43.0%*	Common Equity Ratio	*45.0%*
							3345.1	3601.9	3986.3	4155.5	4625.6	4946.0	5597.3	5777.0	6471.3	6937.1	*7400*	*7865*	Total Capital ($mill)	*9250*
							2941.2	3300.9	3665.2	3970.5	4352.0	4680.1	5055.7	5370.4	5778.9	6243.3	*6550*	*6860*	Net Plant ($mill)	*8000*
							5.1%	4.9%	5.0%	6.3%	5.1%	2.9%	5.8%	4.9%	4.8%	5.1%	*5.0%*	*5.0%*	Return on Total Cap'l	*5.5%*
							8.7%	8.2%	8.1%	9.5%	7.3%	3.5%	10.2%	7.8%	7.5%	7.8%	*7.5%*	*7.5%*	Return on Shr. Equity	*9.0%*
							8.7%	8.2%	8.1%	9.5%	7.9%	3.2%	10.6%	8.0%	7.6%	7.9%	*7.5%*	*7.5%*	Return on Com Equity	*9.0%*
							3.7%	3.3%	3.3%	4.7%	2.7%	NMF	5.1%	2.5%	1.9%	2.3%	*1.0%*	*1.0%*	Retained to Com Eq	*2.5%*
							58%	59%	60%	51%	66%	NMF	54%	71%	76%	72%	*86%*	*85%*	All Div'ds to Net Prof	*74%*

CAPITAL STRUCTURE as of 12/31/24
Total Debt $4898.2 mill. **Due in 5 Yrs**$1766.0 mill.
LT Debt $3697.7 mill. **LT Interest** $185.0 mill.
(Total interest coverage: 2.5x)

Leases, Uncapitalized Annual rentals $9.8 mill.
Pension Assets-9/24 $704.5 mill.
Oblig. $887.3 mill.
Pfd Stock $242.0 mill. **Pfd Div'd** $14.8 mill.
Common Stock 58,345,839 shs.
as of 1/31/25

MARKET CAP: $4.2 billion (Mid Cap)

CURRENT POSITION ($MILL.)	2023	2024	12/31/24
Cash Assets	5.6	4.5	11.5
Other	1071.3	766.8	976.5
Current Assets	1076.9	771.3	988.0
Accts Payable	253.1	237.2	292.3
Debt Due	1112.1	989.0	1200.5
Other	390.2	477.7	498.4
Current Liab.	1755.4	1703.9	1991.2
Fix. Chg. Cov.	294%	305%	310%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '22-'24 to '28-'30
Revenues	1.5%	4.0%	*1.0%*
"Cash Flow"	8.5%	4.0%	*4.0%*
Earnings	5.5%	1.0%	*4.5%*
Dividends	5.5%	5.0%	*4.0%*
Book Value	5.0%	3.0%	*2.5%*

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.)[A] Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2022	555.4	880.9	448.0	314.2	2198.5
2023	814.0	1123.4	418.5	310.4	2666.3
2024	756.6	1128.5	414.1	293.8	2593.0
2025	669.1	*1120.9*	*415*	*300*	*2505*
2026	*715*	*1135*	*430*	*320*	*2600*

Fiscal Year Ends	EARNINGS PER SHARE [A B F] Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2022	1.01	3.27	d.10	d.20	3.95
2023	1.66	3.33	d.48	d.66	3.85
2024	1.52	3.58	d.28	d.51	4.19
2025	1.34	*3.40*	*d.30*	*d.49*	*3.95*
2026	*1.43*	*3.47*	*d.27*	*d.48*	*4.15*

Cal-endar	QUARTERLY DIVIDENDS PAID [C■] Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	.65	.65	.65	.65	2.60
2022	.685	.685	.685	.685	2.74
2023	.72	.72	.72	.72	2.88
2024	.755	.755	.755	.755	3.02
2025	.785				

BUSINESS: Spire Inc., formerly known as the Laclede Group, Inc., is a holding company for natural gas utilities, which distributes natural gas across Missouri, including the cities of St. Louis and Kansas City, Alabama, and Mississippi. Has roughly 1.7 million customers. Acquired Missouri Gas 9/13, Alabama Gas Co 9/14. Utility therms sold and transported in fiscal 2024: 3.1 bill. Revenue mix for regulated operations: residential, 66%; commercial and industrial, 24%; transportation, 5%; other, 5%. Officers and directors own 2.3% of common shares; BlackRock, 11.9%; The Vanguard Group, 9.6% (12/24 proxy). Chairman: Edward Glotzbach; CEO: Steve Lindsey. Inc.: Missouri. Address: 700 Market Street, St. Louis, Missouri 63101. Tel.: 314-342-0500. Internet: www.spireenergy.com.

Spire got off to a rather uninspiring start in fiscal 2025 (ends September 30th). First-quarter earnings per share slipped 11.8%, to $1.34, versus the prior year's $1.52 result. That stemmed partially from diminished profits in the Gas Marketing division, given less favorable market conditions coupled with increased transportation and storage fees. There was a greater number of diluted shares outstanding, too. But the Gas Utility unit and Midstream segment had better showings during the period. Still, for the full year, we think the company's bottom line will retreat about 6%, to $3.95 per share, relative to fiscal 2024's $4.19 figure. Concerning fiscal 2026, however, earnings stand to recover around 5%, to $4.15 a share. That is based, to a certain degree, on our assumption that the business climate brightens. Improvements in operating efficiencies should lend further support.

Capital expenditures for this year are anticipated to be $790 million. (That's 8.3% lower than the fiscal 2024 level of $861.3 million.) The bulk of the funds are being deployed to infrastructure upgrades, the installation of advanced meters, plus new business development initiatives at the utilities. Management adds that it expects total capital spending from fiscal 2025 through fiscal 2034 to be $7.4 billion. If the balance sheet remains in sound condition, we believe that Spire will have minimal difficulty accomplishing these objectives.

The quarterly common stock dividend was raised about 4%, to $0.785 per share. That was made possible, no doubt, by the company's solid capital position. What's more, we anticipate additional steady hikes in the distribution out to 2028-2030. The payout ratio over that span should be manageable, in the neighborhood of 74%. It is worth mentioning that the dividend yield looks attractive when compared to the average of all Natural Gas Utility equities within the *Value Line* universe.

Besides the generous income component, there's not much else here, right now. At the recent quotation, 3- to 5-year capital appreciation possibilities are limited. Meanwhile, SR shares are ranked just 3 (Average) for Timeliness.

Frederick L. Harris, III February 21, 2025

(A) Fiscal year ends Sept. 30th.
(B) Based on diluted shares outstanding. Next earnings report due late April.
(C) Dividends paid in early January, April, July, and October. ■ Dividend reinvestment plan available.
(D) Includes deferred charges. In '24: $1,171.6 mill., $20.31/sh.
(E) In millions.
(F) Quarterly earnings may not sum due to rounding or change in shares outstanding.

Company's Financial Strength	B++
Stock's Price Stability	90
Price Growth Persistence	25
Earnings Predictability	50

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ALLIANT ENERGY NDQ-LNT

RECENT PRICE **63.63** | P/E RATIO **19.9** (Trailing: 22.6 Median: 21.0) | RELATIVE P/E RATIO **1.04** | DIV'D YLD **3.0%** | **VALUE LINE**

TIMELINESS 3 Raised 5/3/24
SAFETY 1 Raised 9/6/24
TECHNICAL 3 Lowered 11/29/24
BETA .90 (1.00 = Market)

18-Month Target Price Range

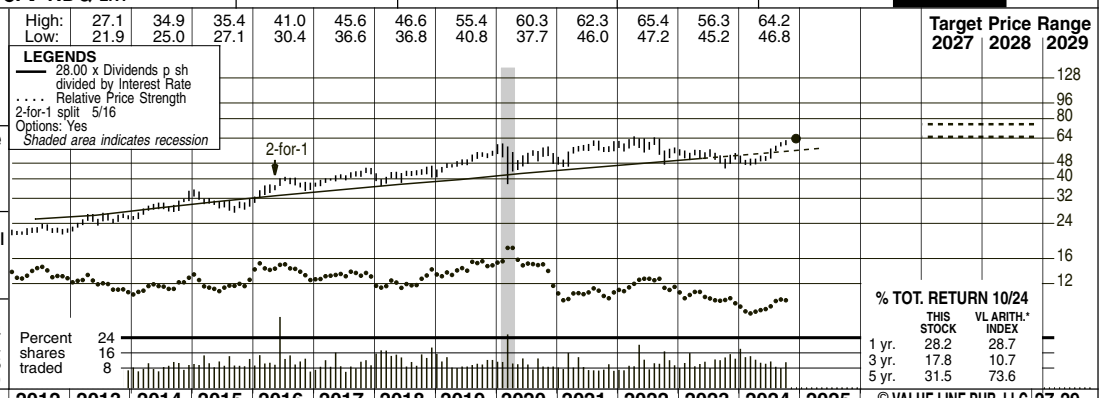
Low-High	Midpoint (% to Mid)
$46-$73	$60 (-5%)

2027-29 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	75	(+20%)	*7%*
Low	65	(Nil)	*4%*

Institutional Decisions

	4Q2023	1Q2024	2Q2024
to Buy	312	290	314
to Sell	279	311	265
Hld's(000)	209105	208018	205430



2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	© VALUE LINE PUB. LLC	27-29
16.67	15.51	15.40	16.51	13.94	14.77	15.10	14.34	14.58	14.62	14.97	14.89	13.67	14.65	16.74	15.72	*16.15*	*17.30*	Revenues per sh	*18.35*
2.28	2.10	2.60	2.75	2.95	3.34	3.49	3.45	3.43	3.97	4.32	4.59	4.92	5.25	5.40	5.38	*5.55*	*5.85*	"Cash Flow" per sh	*6.50*
1.27	.95	1.38	1.38	1.53	1.65	1.74	1.69	1.65	1.99	2.19	2.33	2.47	2.63	2.73	2.78	*2.95*	*3.25*	Earnings per sh A	*3.90*
.70	.75	.79	.85	.90	.94	1.02	1.10	1.18	1.26	1.34	1.42	1.52	1.61	1.71	1.81	*1.92*	*2.04*	Div'd Decl'd per sh B ■ †	*2.43*
3.98	5.43	3.91	3.03	5.22	3.32	3.78	4.25	5.26	6.34	6.92	6.69	5.47	4.67	5.91	7.24	*5.80*	*5.60*	Cap'l Spending per sh	*5.40*
12.78	12.54	13.05	13.57	14.12	14.79	15.54	16.41	16.96	18.08	19.43	21.24	22.76	23.91	24.99	26.46	*27.65*	*28.85*	Book Value per sh C	*31.90*
220.90	221.31	221.79	222.04	221.97	221.89	221.87	226.92	227.67	231.35	236.06	245.02	249.87	250.47	251.14	256.10	*256.70*	*256.70*	Common Shs Outst'g D	*257.00*
13.4	13.9	12.5	14.5	14.5	15.3	16.6	18.1	22.3	20.6	19.1	21.2	21.2	21.2	21.4	18.8	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	*18.0*
.81	.93	.80	.91	.92	.86	.87	.91	1.17	1.04	1.03	1.13	1.09	1.15	1.24	1.05			Relative P/E Ratio	*1.00*
4.1%	5.7%	4.6%	4.3%	4.1%	3.7%	3.5%	3.6%	3.2%	3.1%	3.2%	2.9%	2.9%	2.9%	2.9%	3.5%			Avg Ann'l Div'd Yield	*3.7%*
3350.3	3253.6	3320.0	3382.2	3534.5	3647.7	3416.0	3669.0	4205.0	4027.0	*4150*	*4440*	Revenues ($mill)	*4720*
395.7	390.9	384.0	466.1	522.3	567.4	624.0	674.0	686.0	703.0	*755*	*835*	Net Profit ($mill)	*975*
10.1%	15.3%	13.4%	12.5%	8.4%	10.8%	- -	- -	3.1%	.6%	*2.0%*	*2.0%*	Income Tax Rate	*2.0%*
8.8%	9.4%	16.3%	10.7%	14.5%	16.3%	8.8%	3.7%	8.7%	14.2%	*6.0%*	*6.0%*	AFUDC % to Net Profit	*4.0%*
49.7%	47.3%	51.5%	47.8%	52.3%	50.6%	53.5%	52.9%	55.0%	54.8%	*56.5%*	*55.0%*	Long-Term Debt Ratio	*52.0%*
47.5%	50.0%	46.1%	49.8%	45.7%	47.6%	44.9%	47.1%	45.0%	45.2%	*43.5%*	*45.0%*	Common Equity Ratio	*48.0%*
7257.2	7446.3	8377.6	8392.8	10032	10938	12657	12725	13944	15002	*16220*	*16530*	Total Capital ($mill)	*17070*
6442.0	8970.2	9809.9	10798	12462	13527	14336	14987	16247	17157	*18300*	*18600*	Net Plant ($mill)	*19180*
6.5%	6.3%	5.6%	6.7%	6.3%	6.3%	5.9%	6.3%	6.1%	6.0%	*6.0%*	*6.5%*	Return on Total Cap'l	*7.0%*
10.8%	10.0%	9.5%	10.6%	10.9%	10.5%	10.6%	11.3%	10.9%	10.4%	*11.0%*	*11.5%*	Return on Shr. Equity	*12.0%*
11.2%	10.2%	9.7%	10.9%	11.2%	10.7%	10.8%	11.0%	10.9%	10.4%	*11.0%*	*11.5%*	Return on Com Equity E	*12.0%*
4.6%	3.6%	2.8%	4.0%	4.4%	4.2%	4.2%	4.3%	4.1%	3.6%	*4.0%*	*4.0%*	Retained to Com Eq	*4.5%*
60%	66%	72%	64%	62%	61%	62%	62%	62%	65%	*63%*	*63%*	All Div'ds to Net Prof	*62%*

CAPITAL STRUCTURE as of 9/30/24
Total Debt $10679 mill. **Due in 5 Yrs** $2984 mill.
LT Debt $9245 mill. **LT Interest** $370 mill.
(LT interest earned: 2.8x)

Leases, Uncapitalized Annual rentals $3 mill.

Pension Assets-12/23 $732 mill.
Oblig $876 mill.

Pfd Stock None

Common Stock 256,599,202 shs.

MARKET CAP: $16.3 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2021	2022	2023
% Change Retail Sales (KWH)	+3.7	-.7	
Avg. Indust. Use (MWH)	11696	11494	11435
Avg. Indust. Revs. per KWH (¢)	7.64	8.39	8.47
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	5486	5629	5856
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+.8	+.7	+.7
Fixed Charge Cov. (%)	259	NA	NA

ANNUAL RATES of change (per sh)

	Past 10 Yrs.	Past 5 Yrs.	Est'd '21-'23 to '27-'29
Revenues	.5%	1.5%	*2.5%*
"Cash Flow"	6.0%	6.5%	*2.0%*
Earnings	6.0%	7.0%	*6.0%*
Dividends	6.5%	6.5%	*6.0%*
Book Value	6.0%	6.5%	*4.0%*

QUARTERLY REVENUES ($ mill.)

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	901	817	1024	927	3669
2022	1068	943	1135	1059	4205
2023	1077	912	1077	961	4027
2024	1031	894	1081	*1144*	*4150*
2025	*1065*	*1005*	*1185*	*1185*	*4440*

EARNINGS PER SHARE A

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	.68	.57	1.02	.35	2.63
2022	.77	.63	.90	.43	2.73
2023	.65	.64	1.02	.47	2.78
2024	.62	.57	1.15	*.61*	*2.95*
2025	*.74*	*.69*	*1.14*	*.68*	*3.25*

QUARTERLY DIVIDENDS PAID B ■ †

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2020	.38	.38	.38	.38	1.52
2021	.4025	.4025	.4025	.4025	1.61
2022	.4275	.4275	.4275	.4275	1.71
2023	.4525	.4525	.4525	.4525	1.81
2024	.48	.48	.48	.48	

BUSINESS: Alliant Energy Corporation is the parent company of Interstate Power and Light Company (IPL) and Wisconsin Power and Light Company (WPL). Together, the utility subsidiaries serve approximately one million electric and 425,000 natural gas customers in Wisconsin and Iowa. Electric revenue: residential, 36%; commercial, 25%; industrial, 29%; wholesale, 8%; other, 2%. Generating sources: coal, 32%; gas, 32%; wind, 16%; other, 1%; purchased, 19%. Fuel costs: 25% of revenues. '23 reported depreciation rates: 2.9%-6.1%. Has 3,300 employees. Chairman, President & CEO: John O. Larsen. Incorporated: Wisconsin. Address: 4902 N. Biltmore Lane, Madison, WI 53718-2148. Telephone: 608-458-3311. Internet: www.alliantenergy.com.

Alliant Energy could very well enjoy a strong boost in power demand, beginning in 2028. To that point, management recently announced that the electric utility was preparing to bring two "prestigious" data-center (DC) customers on board, both of which would operate out of Alliant's Big Cedar Industrial Center in Cedar Rapids, Iowa. As we understand it, the first phase of the Big Cedar DC opportunity is likely to increase peak demand by 1.1 gigawatts and go live sometime in late 2028. What's more, assuming Alliant continues to have success attracting commercial customers to the Hawkeye State, a second phase could be launched, potentially by decade's end.

Alliant remains focused on reducing its reliance on fossil fuels. To wit, its Interstate Power & Light subsidiary continues to target 400 megawatts of solar power generation by the end of 2024. Meantime, Wisconsin Power & Light was recently expected to complete the last of several projects that will increase the utility's overall solar-power capacity in the Badger State to 1.1 gigawatts. Importantly, these solar projects have zero fuel costs, thus reducing Alliant's susceptibility to swings in natural-gas prices and the like. Its investments in "green" power also yield significant tax credits that can be sold to regional manufacturers and other third parties looking to maintain compliance with restrictions on harmful carbon emissions. In 2025 alone, Alliant could realize as much as $400 million from the sale of tax credits.

The power company is likely to get a bit leaner. Indeed, in the December quarter, Alliant initiated a voluntary employee separation program that may very well result in a 5% reduction in its overall workforce. More than 160 workers could be impacted.

Alliant Energy shares remain neutrally ranked for relative year-ahead price performance. And with the stock up 23% in price year to date, long-term appreciation potential no longer stands out. Still, the utility company boasts an attractive, well-covered dividend that could hold some appeal for income-oriented accounts (current yield: 3.0% versus 1.9% for the *Value Line* universe as a whole).

Nils C. Van Liew *December 6, 2024*

(A) Diluted EPS. Excl. nonrecurring losses: '11, 1¢; '12, 8¢. '20 & '21 EPS don't sum due to rounding. Next earnings report due late Feb. **(B)** Dividends historically paid in mid-Feb., May, Aug., and Nov. ■ Dividend reinvestment plan avail. † Shareholder investment plan avail. **(C)** Incl. deferred charges. In '21: $1,980 mill., $7.91/sh. **(D)** In millions, adj. for split. **(E)** Rate base: Orig. cost. Rates all'd on com. eq. in IA in '20: various; in WI in '22: 10%; earned on avg. com. eq., '21: 11.3%. Regulatory Climate: Wisconsin, Above Average; Iowa, Average.

Company's Financial Strength	A+
Stock's Price Stability	90
Price Growth Persistence	55
Earnings Predictability	100

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AMEREN NYSE-AEE

RECENT PRICE **82.57** | P/E RATIO **17.1** (Trailing: 18.7 Median: 20.0) | RELATIVE P/E RATIO **0.93** | DIV'D YLD **3.2%** | **VALUE LINE**

TIMELINESS 4 Lowered 12/29/23
SAFETY 1 Raised 9/10/21
TECHNICAL 5 Lowered 8/2/24
BETA .90 (1.00 = Market)

18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$61-$95	$78 (-5%)

2027-29 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	130	(+55%)	*14%*
Low	110	(+35%)	*9%*

Institutional Decisions

	3Q2023	4Q2023	1Q2024
to Buy	280	283	274
to Sell	314	321	321
Hld's(000)	210352	215268	218776

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	Target Price Range 2027	2028	2029
High:	37.3	48.1	46.8	54.1	64.9	70.9	80.9	87.7	90.8	99.2	91.2	84.4										
Low:	30.6	35.2	37.3	41.5	51.4	51.9	63.1	58.7	69.8	73.3	69.7	67.0										

LEGENDS
35.70 x Dividends p sh
Relative Price Strength
Options: Yes
Shaded area indicates recession

% TOT. RETURN 7/24

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-4.2	9.9
3 yr.	3.2	12.6
5 yr.	19.8	72.0

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	© VALUE LINE PUB. LLC	27-29
	36.92	29.87	31.77	31.04	28.14	24.06	24.95	25.13	25.04	25.46	25.73	24.00	22.87	24.81	30.37	28.10	***28.45***	***29.80***	Revenues per sh	***33.35***
	6.44	6.06	6.33	5.87	5.87	5.25	5.77	6.08	6.59	6.80	7.64	7.83	8.08	8.89	9.59	9.99	***10.50***	***11.15***	"Cash Flow" per sh	***12.35***
	2.88	2.78	2.77	2.47	2.41	2.10	2.40	2.38	2.68	2.77	3.32	3.35	3.50	3.84	4.14	4.37	***4.60***	***4.90***	Earnings per sh [A]	***6.00***
	2.54	1.54	1.54	1.56	1.60	1.60	1.61	1.66	1.72	1.78	1.85	1.92	2.00	2.20	2.36	2.52	***2.68***	***2.86***	Div'd Decl'd per sh [B] ■	***3.30***
	9.75	7.51	4.66	4.50	5.49	5.87	7.66	8.12	8.78	9.05	9.56	9.92	13.02	13.67	12.79	12.87	***12.55***	***12.80***	Cap'l Spending per sh	***13.00***
	32.80	33.08	32.15	32.64	27.27	26.97	27.67	28.63	29.27	29.61	31.21	32.73	35.29	37.64	40.11	40.26	***42.90***	***45.95***	Book Value per sh [C]	***52.65***
	212.30	237.40	240.40	242.60	242.63	242.63	242.63	242.63	242.63	242.63	244.50	246.20	253.30	257.70	262.00	267.00	***267.00***	***272.00***	Common Shs Outst'g [D]	***285.00***
	14.2	9.3	9.7	11.9	13.4	16.5	16.7	17.5	18.3	20.6	18.3	22.1	22.2	21.4	21.5	18.8	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	***20.0***
	.85	.62	.62	.75	.85	.93	.88	.88	.96	1.04	.99	1.18	1.14	1.16	1.24	1.07			Relative P/E Ratio	***1.10***
	6.2%	6.0%	5.8%	5.3%	5.0%	4.6%	4.0%	4.0%	3.5%	3.1%	3.0%	2.6%	2.6%	2.7%	2.7%	3.3%			Avg Ann'l Div'd Yield	***3.0%***
							6053.0	6098.0	6076.0	6177.0	6291.0	5910.0	5794.0	6394.0	7957.0	7500.0	***7600***	***8100***	Revenues ($mill)	***9500***
							593.0	585.0	659.0	683.0	821.0	834.0	877.0	995.0	1074.0	1152.0	***1230***	***1335***	Net Profit ($mill)	***1710***
							38.9%	38.3%	36.7%	38.2%	22.4%	17.9%	15.0%	13.6%	14.0%	12.0%	***12.0%***	***12.0%***	Income Tax Rate	***12.0%***
							5.7%	5.1%	4.1%	5.6%	6.9%	5.8%	5.5%	6.0%	5.0%	6.0%	***5.0%***	***5.0%***	AFUDC % to Net Profit	***4.0%***
							47.2%	49.3%	47.7%	49.2%	50.3%	52.1%	55.0%	56.1%	56.6%	55.7%	***53.5%***	***52.5%***	Long-Term Debt Ratio	***51.0%***
							51.7%	49.7%	51.3%	49.8%	48.8%	47.1%	44.3%	43.3%	43.4%	43.8%	***46.0%***	***47.0%***	Common Equity Ratio	***48.5%***
							12975	13968	13840	14420	15632	17116	20158	22391	24193	24847	***25750***	***26450***	Total Capital ($mill)	***29500***
							17424	18799	20113	21466	22810	24376	26807	29261	31262	33776	***35000***	***36300***	Net Plant ($mill)	***38400***
							5.8%	5.3%	6.0%	6.0%	6.4%	6.0%	5.3%	5.3%	5.4%	5.5%	***5.0%***	***5.0%***	Return on Total Cap'l	***6.0%***
							8.7%	8.3%	9.1%	9.3%	10.6%	10.2%	9.7%	10.1%	10.2%	11.0%	***11.0%***	***11.0%***	Return on Shr. Equity	***10.0%***
							8.7%	8.3%	9.2%	9.4%	10.7%	10.3%	9.7%	10.2%	10.2%	11.0%	***11.0%***	***11.0%***	Return on Com Equity [E]	***10.0%***
							2.9%	2.5%	3.3%	3.4%	4.8%	4.4%	4.2%	4.4%	4.4%	5.0%	***5.0%***	***5.0%***	Retained to Com Eq	***4.0%***
							67%	70%	64%	64%	56%	57%	57%	57%	57%	57%	***56%***	***56%***	All Div'ds to Net Prof	***60%***

CAPITAL STRUCTURE as of 9/30/24
Total Debt $16722 mill. **Due in 5 Yrs** $2789 mill.
LT Debt $16422 mill. **LT Interest** $450 mill.
(LT interest earned: 3.8x)
Pension Assets-12/23 $5745 mill.
Oblig $5457 mill.
Pfd Stock $129 mill. **Pfd Div'd** $5 mill.
807,595 sh. $3.50 to $5.50 cum. (no par), $100 stated val., redeem. $102.176-$110/sh.; 487,508 sh. 4.00% to 5.16%, $100 par, redeem. $100-$104.30/sh.
Common Stock 266,927,767 shs.
as of 10/31/24
MARKET CAP: $22.0 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2021	2022	2023
% Change Retail Sales (KWH)	-5.6	+2.1	+3.2
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	NA	NA	NA
Fixed Charge Cov. (%)	291	325	334

ANNUAL RATES of change (per sh)

	Past 10 Yrs.	Past 5 Yrs.	Est'd '21-'23 to '27-'29
Revenues	-1.5%	.5%	*4.0%*
"Cash Flow"	4.0%	6.5%	*5.5%*
Earnings	4.0%	8.0%	*6.5%*
Dividends	3.5%	5.0%	*6.5%*
Book Value	2.0%	5.5%	*6.5%*

QUARTERLY REVENUES ($ mill.)

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	1566	1472	1811	1545	6394
2022	1879	1726	2306	2046	7957
2023	2062	1760	2060	1618	7500
2024	1816	1693	2173	***1918***	***7600***
2025	***1950***	***1800***	***2250***	***2100***	***8100***

EARNINGS PER SHARE [A]

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	.91	.80	1.65	.48	3.84
2022	.97	.80	1.74	.63	4.14
2023	1.00	.90	1.87	.60	4.37
2024	.98	.97	1.87	***.78***	***4.60***
2025	***1.10***	***1.00***	***1.95***	***.85***	***4.90***

QUARTERLY DIVIDENDS PAID [B] ■

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2020	.495	.495	.495	.515	2.00
2021	.55	.55	.55	.55	2.20
2022	.59	.59	.59	.59	2.36
2023	.63	.63	.63	.63	2.52
2024	.67	.67	.67	.67	

BUSINESS: Ameren Corporation is a holding company formed through the merger of Union Electric and CIPSCO. Has 1.2 million electric and 127,000 gas customers in Missouri; 1.2 million electric and 813,000 gas customers in Illinois. Discontinued nonregulated power-generation operation in '13. Electric revenue breakdown: residential, 49%; commercial, 34%; industrial, 8%; other, 9%. Generating sources: coal, 73%; nuclear, 11%; hydro & other, 9%; purchased, 7%. Fuel costs: 25% of revenues. Has approximately 9,250 employees. Chairman: Warner L. Baxter. President & CEO: Martin J. Lyons, Jr. Inc.: Missouri. Address: One Ameren Plaza, 1901 Chouteau Ave., P.O. Box 66149, St. Louis, MO 63166-6149. Tel.: 314-621-3222. Internet: www.ameren.com.

Ameren is poised to report solid results in 2024. The utility is benefiting from elevated power demand, strategic infrastructure investments, and disciplined cost management. Our profit estimate remains at $4.60 per share, which is right near the midpoint of management's updated target range of $4.55-$4.69. Ameren looks to close out the year with significant year-over-year operations and maintenance cost reductions from several savings initiatives. Meanwhile, these shares have jumped nicely in value as of late. Indeed, the stock is up nearly 15% over the past three months and has risen more than 30% in 2024, thanks to solid financial results and a strong outlook in the coming years.

We look for sharper top- and bottom-line growth next year. The utility is well positioned to benefit from clean energy advancements and its three solar facilities, as well as additional rate relief from its transmission and Illinois Electric operations over that interim. Indeed, Ameren recently received approval to build an 800 megawatt (mw) natural gas energy center, which is expected to be operational in 2027. The utility also acquired the Huck Finn renewable energy center, a 200 mw solar facility in Missouri. Ameren is also well positioned over that interim to benefit from increased demand for power from data centers and artificial intelligence innovations. Accordingly, we look for 2025 earnings of $4.90 per share, indicating an increase of 7% from our 2024 estimate. We also raised our top-line target by $100 million to reflect clean energy and regulatory advancements.

We think that the quarterly disbursement will be boosted by $0.04 a share (6%) in 2025. Ameren's goals for the dividend include hikes in line with profit growth and a payout ratio of 55%-70%.

These shares are suitable for conservative, income-oriented investors. Both short- and long-term capital gains prospects are below average at this juncture. But, the 1 (Highest) Safety rank and top (100) Earnings Predictability score should appeal to risk-averse accounts. The stock's dividend is perhaps its most notable feature, though it is about average by utility standards.

Zachary J. Hodgkinson *December 6, 2024*

(A) Diluted EPS. Excl. nonrec. gain (losses): '10, ($2.19); '11, (32¢); '12, ($6.42); '17, (63¢); gain (loss) from discontinued ops.: '13, (92¢); '15, 21¢. Next earnings report due early Feb.

(B) Div'ds paid late Mar., June, Sept., & Dec. ■ Div'd reinvest. plan avail. **(C)** Incl. intang. In '23: $6.60/sh. **(D)** In mill. **(E)** Rate base: Orig. cost depr. Rate allowed on com. eq. in MO in '23: elec. & gas, none specified; in IL: electric, varies; in '23: gas, 9.68%; earned on avg. com. eq., '23: 10.5%.

Company's Financial Strength	A+
Stock's Price Stability	95
Price Growth Persistence	85
Earnings Predictability	100

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AMERICAN ELEC. PWR. NDQ-AEP

RECENT PRICE **99.02** | P/E RATIO **16.8** (Trailing: 17.9 Median: 18.0) | RELATIVE P/E RATIO **0.92** | DIV'D YLD **3.6%** | **VALUE LINE**

TIMELINESS 4 Lowered 6/14/24
SAFETY 1 Raised 3/17/17
TECHNICAL 3 Lowered 8/2/24
BETA .85 (1.00 = Market)

18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$71-$114	$93 (-5%)

2027-29 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	140	(+40%)	*12%*
Low	115	(+15%)	*7%*

Institutional Decisions

	3Q2023	4Q2023	1Q2024
to Buy	599	628	661
to Sell	557	609	572
Hld's(000)	391405	398265	402930

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	© VALUE LINE PUB. LLC	27-29
High:	51.6	63.2	65.4	71.3	78.1	81.1	96.2	105.0	91.5	105.6	98.3	104.4								
Low:	41.8	45.8	52.3	56.8	61.8	62.7	72.3	65.1	74.8	80.3	69.4	75.2								
	35.56	28.22	30.01	31.27	30.77	31.48	34.78	33.51	33.31	31.35	32.84	31.49	30.04	33.30	38.20	36.08	*37.70*	*40.20*	Revenues per sh	*41.80*
	6.84	6.32	6.29	6.83	6.92	7.02	7.57	7.98	8.47	7.95	8.77	9.35	10.28	10.98	10.72	10.92	*11.75*	*12.20*	"Cash Flow" per sh	*15.05*
	2.99	2.97	2.60	3.13	2.98	3.18	3.34	3.59	4.23	3.62	3.90	4.08	4.42	4.96	5.09	5.24	*5.65*	*5.85*	Earnings per sh [A]	*7.05*
	1.64	1.64	1.71	1.85	1.88	1.95	2.03	2.15	2.27	2.39	2.53	2.71	2.84	3.00	3.17	3.37	*3.60*	*3.81*	Div'd Decl'd per sh [B] ■ †	*4.16*
	9.83	6.19	5.07	5.74	6.45	7.75	8.68	9.37	9.98	11.79	12.89	12.43	12.72	11.43	13.18	13.89	*14.15*	*14.10*	Cap'l Spending per sh	*14.00*
	26.33	27.49	28.33	30.33	31.37	32.98	34.37	36.44	35.38	37.17	38.58	39.73	41.38	44.49	46.60	48.46	*55.05*	*58.90*	Book Value per sh [C]	*62.55*
	406.07	478.05	480.81	483.42	485.67	487.78	489.40	491.05	491.71	492.01	493.25	494.17	496.60	504.21	513.87	526.18	*533.00*	*535.00*	Common Shs Outst'g [D]	*550.00*
	13.1	10.0	13.4	11.9	13.8	14.5	15.9	15.8	15.2	19.3	18.0	21.4	19.6	17.1	21.1	16.2	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	*18.0*
	.79	.67	.85	.75	.88	.81	.84	.80	.80	.97	.97	1.14	1.01	.92	1.23	.93			Relative P/E Ratio	*1.00*
	4.2%	5.5%	4.9%	5.0%	4.6%	4.2%	3.8%	3.8%	3.5%	3.4%	3.6%	3.1%	3.3%	3.5%	3.3%	4.5%			Avg Ann'l Div'd Yield	*3.3%*
	17020	16453	16380	15425	16196	15561	14919	16792	19640	18982	*20100*	*21500*	Revenues ($mill)	*23000*
	1634.0	1763.4	2073.6	1783.2	1923.8	2019.0	2200.1	2448.1	2307.2	2208.1	*3010*	*3130*	Net Profit ($mill)	*3880*
	37.8%	35.1%	26.8%	33.7%	5.8%	.7%	1.9%	4.6%	NMF	NMF	*21.0%*	*21.0%*	Income Tax Rate	*21.0%*
	9.0%	11.0%	8.0%	8.0%	10.7%	12.7%	9.7%	7.8%	7.0%	7.0%	*7.0%*	*6.5%*	AFUDC % to Net Profit	*5.0%*
	49.0%	49.8%	50.0%	51.5%	53.2%	56.1%	58.5%	58.3%	58.5%	58.2%	*58.0%*	*58.0%*	Long-Term Debt Ratio	*57.5%*
	51.0%	50.2%	50.0%	48.5%	46.8%	43.9%	41.5%	41.7%	42.0%	42.0%	*42.0%*	*42.0%*	Common Equity Ratio	*42.5%*
	33001	35633	34775	37707	40677	44759	49537	53734	57520	62837	*68900*	*70730*	Total Capital ($mill)	*75900*
	44117	46133	45639	50262	55099	60138	63902	66001	71283	76693	*78000*	*81250*	Net Plant ($mill)	*87300*
	6.3%	6.1%	7.2%	5.9%	5.9%	5.6%	5.6%	5.6%	4.0%	3.6%	*4.5%*	*4.5%*	Return on Total Cap'l	*5.0%*
	9.7%	9.9%	11.9%	9.8%	10.1%	10.3%	10.7%	11.1%	9.7%	8.7%	*10.0%*	*10.0%*	Return on Shr. Equity	*11.0%*
	9.7%	9.9%	11.9%	9.8%	10.1%	10.3%	10.7%	11.1%	9.7%	8.7%	*10.0%*	*10.0%*	Return on Com Equity	*11.0%*
	3.8%	3.9%	5.5%	3.2%	3.5%	3.4%	3.8%	4.3%	2.9%	2.4%	*4.0%*	*4.0%*	Retained to Com Eq	*4.5%*
	61%	60%	54%	67%	65%	67%	65%	61%	70%	63%	*63%*	*63%*	All Div'ds to Net Prof	*61%*

CAPITAL STRUCTURE as of 9/30/24
Total Debt $41974 mill. **Due in 5 Yrs** $12886 mill.
LT Debt $39148 mill. **LT Interest** $1400 mill.

Leases, Uncapitalized Annual rentals $119.6 mill.

Pfd Stock None

Common Stock 532,565,335 shs.

MARKET CAP: $52.7 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2020	2021	2022
% Change Retail Sales (KWH)	- -	+3.0	- -
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+1.0	NA	NA
Fixed Charge Cov. (%)	243	272	285

ANNUAL RATES

of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '21-'23 to '27-'29
Revenues	.5%	-.5%	*3.0%*
"Cash Flow"	5.0%	5.5%	*5.5%*
Earnings	5.0%	4.0%	*6.5%*
Dividends	5.0%	5.0%	*5.5%*
Book Value	3.5%	3.5%	*6.0%*

QUARTERLY REVENUES ($ mill.) [E]

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	4281	3826	4623	4061	16792
2022	4593	4640	5526	4881	19640
2023	4690	4373	5342	4577	18982
2024	5026	4579	5420	*5075*	*20100*
2025	*5250*	*4850*	*5800*	*5600*	*21500*

EARNINGS PER SHARE [A]

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	1.15	1.15	1.59	1.07	4.96
2022	1.22	1.20	1.62	1.05	5.09
2023	1.11	1.13	1.77	1.23	5.24
2024	1.27	1.25	1.85	*1.28*	*5.65*
2025	*1.30*	*1.40*	*1.85*	*1.30*	*5.85*

QUARTERLY DIVIDENDS PAID [B] ■ †

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2020	.70	.70	.70	.74	2.84
2021	.74	.74	.74	.78	3.00
2022	.78	.78	.78	.83	3.17
2023	.83	.83	.83	.88	3.37
2024	.88	.88	.88	.93	

BUSINESS: American Electric Power Company Inc. (AEP), through 10 operating utilities, serves 5.5 million customers in Arkansas, Kentucky, Indiana, Louisiana, Michigan, Ohio, Oklahoma, Tennessee, Texas, Virginia, & West Virginia. Has a transmission subsidiary. Electric revenue breakdown: residential, 43%; commercial, 23%; industrial, 18%; wholesale, 10%; other, 6%. Sold commercial barge operation in '15. Generating sources not available. Fuel costs: 33% of revenues. '23 reported depreciation rates (utility): 2.6%-12.5%. Has approximately 16,700 employees. Interim Chief Executive Officer: Benjamin G.S. Fowke III. Incorporated: New York. Address: 1 Riverside Plaza, Columbus, Ohio 43215-2373. Telephone: 614-716-1000. Internet: www.aep.com.

American Electric Power is on track to post a strong profit increase this year. Increased investments in its transmission business, elevated volume and power demand, along with a number of pending rate cases, should continue to benefit performance through the end of 2024. Third-quarter earnings of $1.85 per share outperformed our and Wall Street's call of $1.80 due to the aforementioned tailwinds. And, management narrowed its 2024 target range to $5.58-$5.68 a share, right near our unchanged midpoint.

Earnings growth will likely slow down in 2025, though. Despite anticipated growth in the regulated utilities and a significant boost in power demand, lower contributions from the generation and marketing segments due to reduced activities and lower retail and wholesale margins should negatively impact results. Accordingly, we have lowered our 2025 earnings estimate by $0.15 a share, which is at the midpoint of management's updated target range of $5.75-$5.95 a share. We have also slightly pared our 2027-2029 projections by $0.05 a share, and now look for profits of $7.05 a share over that interim. Meanwhile, AEP unveiled a new long-term growth rate of 6%-8% based off its 2025 profit outlook range.

The board of directors raised the dividend, effective with the December payment. This is the typical timing for increases for AEP. The hike was $0.05 a share (6%), in line with the company's 6%-7% long-term earnings growth range and within AEP's target for a payout ratio of 60%-70%.

This issue is best suited for risk-averse investors seeking income. These shares are ranked 4 (Below Average) for Timeliness, making them a weak selection for the year ahead. What's more, intermediate- and long-term capital appreciation potential is nothing to write home about. Indeed, the recent quotation is already above the midpoint of our 18-month Target Price Range. And, over the 2027-2029 period, return prospects are also limited as we look for the stock to trade between $115-$140 over that interim. But, the dividend yield of 3.6% stands above the industrywide average and remains AEP's most notable feature.

Zachary J. Hodgkinson *December 6, 2024*

(A) Diluted EPS. Excl. nonrec. gains (losses): '08, 40¢; '10, (7¢); '11, 89¢; '12, (38¢); '13, (14¢); '16, ($2.99); '17, 26¢; '19, (20¢); gains (loss) from disc. ops.: '08, 3¢; '15, 58¢; '16, (1¢); '22, (58¢); '23, (34¢). Next earnings report due late February. **(B)** Div'ds paid early Mar., June, Sept., & Dec. ■ Div'd reinvestment plan avail. † Shareholder invest. plan avail. **(C)** Incl. intang. In '23: $52.5 million **(D)** In mill. **(E)** Rev. may not sum due to rounding.

Company's Financial Strength	A
Stock's Price Stability	95
Price Growth Persistence	70
Earnings Predictability	90

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DUKE ENERGY NYSE-DUK

RECENT PRICE 112.62 | P/E RATIO 17.8 (Trailing: 19.6 Median: 18.0) | RELATIVE P/E RATIO 0.97 | DIV'D YLD 3.7% | VALUE LINE

TIMELINESS 4 Lowered 10/4/24
SAFETY 2 New 6/1/07
TECHNICAL 2 Lowered 1/24/25
BETA .90 (1.00 = Market)

18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$85-$127	$106 (-5%)

2028-30 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	155	(+40%)	*11%*
Low	115	(Nil)	*4%*

Institutional Decisions

	1Q2024	2Q2024	3Q2024
to Buy	893	923	984
to Sell	830	811	849
Hld's(000)	503341	507258	578742

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
High:	87.3	90.0	87.8	91.8	91.4	97.4	103.8	108.4	116.3	106.4	121.3	112.8						
Low:	67.1	65.5	70.2	76.1	72.0	82.5	62.1	85.6	83.8	83.1	90.1	105.2						

LEGENDS
27.0 x Dividends p sh
Relative Price Strength
1-for-3 Rev split 7/12
Options: Yes
Shaded area indicates recession

Target Price Range 2028 | 2029 | 2030

% TOT. RETURN 12/24

	THIS STOCK	VL ARITH.* INDEX
1 yr.	16.6	13.6
3 yr.	17.1	14.7
5 yr.	44.7	70.9

29.18	32.22	32.63	27.88	34.84	33.84	34.10	32.49	33.66	33.73	34.21	31.04	32.64	37.36	37.69	***39.60***	***41.00***	***42.50***
7.58	8.49	8.68	6.80	8.56	9.11	9.40	9.20	10.01	11.05	12.12	12.04	12.60	12.86	13.45	***14.15***	***15.05***	***15.75***
3.39	4.02	4.14	3.71	3.98	4.13	4.10	3.71	4.22	4.72	5.06	5.12	5.24	5.27	5.56	***5.90***	***6.35***	***6.70***
2.82	2.91	2.97	3.03	3.09	3.15	3.24	3.36	3.49	3.64	3.75	3.82	3.90	3.98	4.06	4.14	***4.22***	***4.30***
9.85	10.84	9.80	7.81	7.83	7.62	9.83	11.29	11.50	12.91	15.17	12.88	12.63	14.76	16.35	***17.50***	***17.75***	***18.00***
49.85	50.84	51.14	58.04	58.54	57.81	57.74	58.62	59.63	60.27	61.20	59.82	61.55	61.51	61.15	***63.00***	***65.15***	***67.75***
436.29	442.96	445.29	704.00	706.00	707.00	688.00	700.00	700.00	727.00	733.00	769.00	769.00	770.00	771.00	***772.50***	***773.00***	***774.00***
13.3	12.7	13.8	17.5	17.4	17.9	18.2	21.3	19.9	17.0	17.7	17.1	18.9	19.8	16.9	***17.8***		
.89	.81	.87	1.11	.98	.94	.92	1.12	1.00	.92	.94	.88	1.02	1.14	.94	***.99***		
6.2%	5.7%	5.2%	4.7%	4.4%	4.3%	4.3%	4.3%	4.2%	4.5%	4.2%	4.4%	3.9%	3.8%	4.3%	4.0%		
23459	22743	23565	24521	25079	23868	25097	28768	29060	***30610***	***31700***	***32900***
2854.0	2560.0	2963.0	3339.0	3747.0	3878.0	4133.0	4166.0	4391.0	***4655***	***5010***	***5290***
32.2%	31.0%	30.4%	14.1%	12.7%	.3%	5.1%	7.4%	9.2%	***9.0%***	***9.0%***	***9.0%***
9.2%	11.7%	12.3%	11.4%	8.0%	6.9%	5.9%	7.6%	9.1%	***9.0%***	***9.0%***	***9.0%***
48.6%	52.6%	54.0%	53.8%	54.0%	53.7%	55.1%	57.6%	59.6%	***61.0%***	***62.0%***	***62.5%***
51.4%	47.4%	46.0%	46.2%	44.1%	44.4%	43.1%	40.7%	38.8%	***38.0%***	***37.5%***	***37.0%***
77222	86609	90774	94940	101807	103589	109744	116383	121564	***127650***	***134525***	***141400***
75709	82520	86391	91694	102127	106782	111408	111748	115315	***122425***	***129400***	***136300***
4.8%	4.0%	4.3%	4.6%	4.7%	4.8%	4.8%	4.6%	4.9%	***5.0%***	***5.0%***	***5.0%***
7.2%	6.2%	7.1%	7.6%	8.0%	8.1%	8.4%	8.4%	8.9%	***9.5%***	***10.0%***	***10.0%***
7.2%	6.2%	7.1%	7.6%	8.3%	8.2%	8.5%	8.6%	9.1%	***9.5%***	***9.5%***	***10.0%***
1.5%	.6%	1.2%	2.0%	2.4%	2.3%	1.9%	2.1%	2.4%	***3.0%***	***3.5%***	***3.5%***
79%	91%	83%	74%	71%	73%	78%	76%	74%	***71%***	***67%***	***65%***

Bold figures are Value Line estimates

© VALUE LINE PUB. LLC	28-30
Revenues per sh	*47.25*
"Cash Flow" per sh	*18.50*
Earnings per sh [A]	*8.00*
Div'd Decl'd per sh [B] ■	*5.00*
Cap'l Spending per sh	*18.75*
Book Value per sh [C]	*76.25*
Common Shs Outst'g [D]	*777.00*
Avg Ann'l P/E Ratio	*17.0*
Relative P/E Ratio	*.95*
Avg Ann'l Div'd Yield	*3.7%*
Revenues ($mill)	*36800*
Net Profit ($mill)	*6320*
Income Tax Rate	*9.0%*
AFUDC % to Net Profit	*8.0%*
Long-Term Debt Ratio	*62.5%*
Common Equity Ratio	*37.0%*
Total Capital ($mill)	*160500*
Net Plant ($mill)	*156000*
Return on Total Cap'l	*5.0%*
Return on Shr. Equity	*10.5%*
Return on Com Equity [E]	*10.5%*
Retained to Com Eq	*4.0%*
All Div'ds to Net Prof	*63%*

CAPITAL STRUCTURE as of 9/30/24
Total Debt $84068 mill. **Due in 5 Yrs** $18322 mill.
LT Debt $76524 mill. **LT Interest** $3020 mill.
Incl. $639 mill. finance leases.
(Total Interest Coverage: 2.5x)
Leases, Uncapitalized Annual rentals $268 mill.
Pension Assets-12/23 $7162 mill.
Oblig. $6299 mill.
Pfd Stock $973 mill. **Pfd Div'd** $106 mill.

Common Stock 772,482,405 shs.
as of 10/31/24

MARKET CAP: $87.0 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2021	2022	2023
% Change Retail Sales (GWH)	+2.5	+4.5%	-4.8%
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (avg.)	+1.6%	+1.8%	+1.7
Fixed Charge Cov. (%)	210	229	209

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '21-'23 to '28-'30
Revenues	1.5%	2.0%	*4.0%*
"Cash Flow"	5.0%	3.5%	*5.0%*
Earnings	3.0%	3.0%	*6.0%*
Dividends	2.5%	2.0%	*3.5%*
Book Value	.5%	.5%	*3.0%*

Calendar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2022	7132	6685	7968	6983	28768
2023	7276	6578	7994	7212	29060
2024	7671	7172	8154	***7613***	***30610***
2025	***7950***	***7425***	***8450***	***7875***	***31700***
2026	***8250***	***7700***	***8775***	***8175***	***32900***

Calendar	EARNINGS PER SHARE [A] Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2022	1.29	1.09	1.78	1.11	5.27
2023	1.20	.91	1.94	1.51	5.56
2024	1.44	1.18	1.62	***1.66***	***5.90***
2025	***1.50***	***1.25***	***1.90***	***1.70***	***6.35***
2026	***1.57***	***1.33***	***2.00***	***1.80***	***6.70***

Calendar	QUARTERLY DIVIDENDS PAID [B] ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	.965	.965	.985	.985	3.90
2022	.985	.985	1.005	1.005	3.98
2023	1.005	1.005	1.025	1.025	4.06
2024	1.025	1.025	1.045	1.045	4.14
2025					

BUSINESS: Duke Energy Corporation is a holding company for utilities with 7.6 mill. elec. customers in NC, FL, IN, SC, OH, and KY, and 1.6 mill. gas customers in OH, KY, NC, SC, and TN. Owns independent power plants & has 25% stake in National Methanol in Saudi Arabia. Acq'd Progress Energy 7/12; Piedmont Natural Gas 10/16; discontinued most int'l ops. in '16. Elec. rev. breakdown: residential, 45%; commercial, 28%; industrial, 13%; other, 14%. Generating sources: gas, 32%; nuclear, 30%; coal, 18%; other, 1%; purchased, 19%. Fuel costs: 28% of revs. '22 reported deprec. rate: 3.6%. Has 27,600 employees. Chairman, President & CEO: Lynn J. Good. Inc.: DE. Address: 550 South Tryon St., Charlotte, NC 28202-1803. Tel.: 704-382-3853. Internet: www.duke-energy.com.

For 2025 and 2026, we expect Duke Energy will continue to build on its solid track record of consecutive annual earnings gains. This assumes that the final tally for 2024, which will be reported on February 13th, is near our $5.90 estimate. The utility is apt to continue to take advantage of strong weather-adjusted electric volume growth and constructive regulatory outcomes over the intermediate term. Solid population growth in its service territories, at three to four times the national average of 0.5%, is a key part of the story. This is largely being driven by strong migration trends in the Carolinas and Florida. The company is also likely to keep benefiting from rate relief (higher regulated price adjustments) as outlined below. Leadership continues to affirm its earnings growth rate of 5%-7% per annum through 2028. As such, we're comfortable with our respective 2025 and 2026 share-earnings projections of $6.35 and $6.70.

Duke Energy has been making steady progress in a number of recent and pending general rate cases (GRC). In the Sunshine State, the Florida Public Service Commission approved a settlement which will increase Duke Energy Florida's base electric rates and assist in the building of solar-energy facilities. The decision will increase rates by $203 million in 2025 and another $59 million in 2026. It also included up to $141 million for a dozen new solar plants as they are completed. The settlement dictates that Duke uses roughly $50 million in federal tax credits to offset the need for a base-rate hike in 2027. Meanwhile, the final order in Duke's South Carolina GRC became effective in August of last year and will increase rates by 13% over a two-year period. The GRC includes $215 million of new investments in highly efficient natural gas, solar, nuclear, and hydroelectric units over a seven-year period. In addition, delivery rates in North Carolina recently increased by 2.9%. Duke also has pending GRCs in Ohio and Indiana with decisions due in the next few quarters.

This equity is untimely. The 3.7% dividend yield is right on the peer-group average. Annual total return prospects are not favorable from the recent valuation.

Anthony J. Glennon *February 7, 2025*

(A) Dil. EPS. Excl. net nonrec. losses: '12, 64¢; '13, 22¢; '14, 59¢; '15, 5¢; '16, 60¢; '18, 96; '20, $3.40; '21, 30¢; '22, $2.10; '23, $2.02; net nonrec. gain: '17, 14¢. Qtly. EPS may not sum to annual figure due to rounding. Next egs. due Feb 13th. **(B)** Div'ds paid mid-Mar., June, Sept., & Dec. ■ Div'd reinv. plan avail. **(C)** Incl. intang. In '23: $42.70/sh. **(D)** In mill., **(E)** Rate base: Net orig. cost. Rate all'd on com. eq. in '21 in NC: 9.6%; 9.5%; in '20 in FL: 9.5%-11.5%; in '20 in IN: 9.7%. in '19 in SC:9.5%; Reg. Clim.: NC, SC Avg.; OH, IN Above Avg.

Company's Financial Strength	A
Stock's Price Stability	95
Price Growth Persistence	45
Earnings Predictability	100

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EDISON INTERNAT'L NYSE-EIX

RECENT PRICE **78.44** | P/E RATIO **15.0** (Trailing: 15.2 Median: 14.0) | RELATIVE P/E RATIO **0.83** | DIV'D YLD **4.3%** | **VALUE LINE**

TIMELINESS 4 Lowered 10/18/24
SAFETY 2 Raised 10/18/24
TECHNICAL 2 Raised 1/3/25
BETA 1.05 (1.00 = Market)

18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$63-$97	$80 (-5%)

2027-29 PROJECTIONS

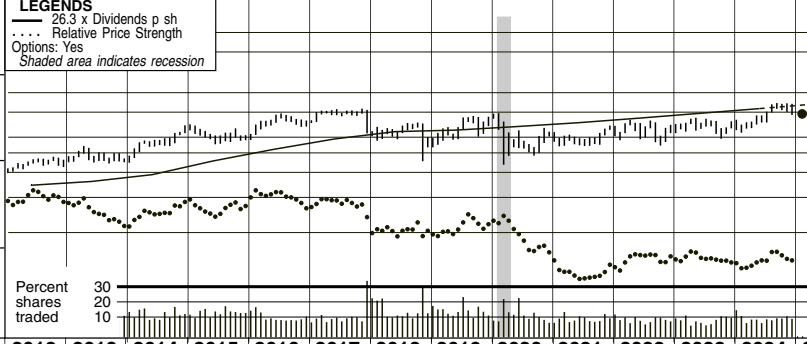
	Price	Gain	Ann'l Total Return
High	120	(+55%)	*15%*
Low	90	(+15%)	*8%*

Institutional Decisions

	1Q2024	2Q2024	3Q2024
to Buy	368	403	454
to Sell	329	300	325
Hld's(000)	344659	343961	379213

	54.2	68.7	69.6	78.7	83.4	71.0	76.4	78.9	68.6	73.3	74.9	88.8
High:	44.3	44.7	55.2	58.0	62.7	45.5	53.4	43.6	53.9	54.4	58.8	63.2
Low:												

LEGENDS
26.3 x Dividends p sh
Relative Price Strength
Options: Yes
Shaded area indicates recession



Target Price Range

2027	2028	2029
200	160	100

80 60 50 40 30 20

% TOT. RETURN 12/24

	THIS STOCK	VL ARITH.* INDEX
1 yr.	16.3	13.6
3 yr.	33.1	14.7
5 yr.	31.8	70.9

2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	© VALUE LINE PUB. LLC	27-29
43.31	37.98	38.09	39.16	36.41	38.61	41.17	35.37	36.43	37.81	38.85	34.11	35.83	39.18	45.05	42.56	*45.05*	*47.30*	Revenues per sh	*54.45*
8.08	7.96	8.41	9.03	9.63	8.80	9.95	10.35	10.43	11.03	4.69	9.39	9.80	10.59	11.51	11.80	*12.80*	*13.60*	"Cash Flow" per sh	*15.10*
3.68	3.24	3.35	3.23	4.55	3.78	4.33	4.15	3.94	4.51	d1.26	4.70	4.52	4.59	4.63	4.76	*4.95*	*5.50*	Earnings per sh [A]	*6.75*
1.23	1.25	1.27	1.29	1.31	1.37	1.48	1.73	1.98	2.23	2.43	2.48	2.58	2.69	2.84	2.99	3.17	*3.36*	Div'd Decl'd per sh [B] ■	*4.00*
8.67	10.07	13.94	14.76	12.73	11.05	11.99	12.97	11.46	11.75	13.84	13.47	14.47	14.47	15.12	14.19	*15.70*	*16.20*	Cap'l Spending per sh	*16.75*
29.21	30.20	32.44	30.86	28.95	30.50	33.64	34.89	36.82	35.82	32.10	36.75	37.08	36.57	35.70	36.02	*38.05*	*40.35*	Book Value per sh [C]	*48.60*
325.81	325.81	325.81	325.81	325.81	325.81	325.81	325.81	325.81	325.81	325.81	361.99	378.91	380.38	382.21	383.93	*387.20*	*389.00*	Common Shs Outst'g [D]	*395.00*
12.4	9.7	10.3	11.8	9.7	12.7	13.0	14.8	17.9	17.2	- -	14.1	13.3	12.9	14.0	14.4	*15.4*		Avg Ann'l P/E Ratio	*15.5*
.75	.65	.66	.74	.62	.71	.68	.75	.94	.87	- -	.75	.68	.70	.81	.80	*.85*		Relative P/E Ratio	*.85*
2.7%	4.0%	3.7%	3.4%	3.0%	2.8%	2.6%	2.8%	2.8%	2.9%	3.8%	3.7%	4.3%	4.5%	4.4%	4.4%	4.1%		Avg Ann'l Div'd Yield	*3.8%*
13413	11524	11869	12320	12657	12347	13578	14905	17220	16338	*17440*	*18400*	Revenues ($mill)	*21500*
1539.0	1480.0	1422.0	1603.0	d290.0	1716.0	1818.0	1907.0	1977.0	2035.0	*2120*	*2345*	Net Profit ($mill)	*2880*
22.4%	6.6%	11.1%	5.0%	- -	1.2%	5.0%	18.0%	12.5%	14.9%	*13.0%*	*13.0%*	Income Tax Rate	*13.0%*
5.8%	8.0%	6.8%	7.2%	- -	9.6%	9.6%	8.8%	9.6%	11.4%	*11.0%*	*10.0%*	AFUDC % to Net Profit	*10.0%*
44.1%	45.0%	41.8%	45.6%	53.6%	53.5%	55.2%	57.6%	60.7%	62.8%	*64.0%*	*64.0%*	Long-Term Debt Ratio	*63.5%*
47.2%	46.7%	49.2%	45.8%	38.3%	39.9%	39.5%	33.2%	30.6%	28.7%	*28.0%*	*28.5%*	Common Equity Ratio	*30.0%*
23216	24352	24362	25506	27284	33360	35581	41959	44547	48260	*52225*	*55375*	Total Capital ($mill)	*66000*
32981	35085	37000	39050	41348	44285	47839	50700	53486	56084	*59100*	*62250*	Net Plant ($mill)	*72200*
7.7%	7.1%	6.9%	7.3%	.1%	6.4%	6.3%	5.6%	5.7%	5.8%	*5.0%*	*5.5%*	Return on Total Cap'l	*5.5%*
11.9%	11.1%	10.0%	11.6%	NMF	11.1%	11.4%	10.7%	11.3%	11.3%	*11.0%*	*12.0%*	Return on Shr. Equity	*12.5%*
13.0%	12.0%	10.8%	12.7%	NMF	12.0%	12.0%	12.5%	12.9%	13.1%	*13.0%*	*13.5%*	Return on Com Equity [E]	*14.0%*
8.8%	7.2%	5.6%	6.6%	NMF	5.9%	5.4%	5.4%	5.2%	5.0%	*4.5%*	*5.5%*	Retained to Com Eq	*5.5%*
37%	44%	53%	52%	NMF	54%	58%	61%	64%	66%	*68%*	*65%*	All Div'ds to Net Prof	*62%*

CAPITAL STRUCTURE as of 9/30/24
Total Debt $35419 mill. **Due in 5 Yrs** $10489 mill.
LT Debt $32303 mill. **LT Interest** $1710 mill.
(Total Interest Coverage: 2.7x)
Leases, Uncapitalized Annual rentals $166 mill.

Pension Assets-12/23 $3609 mill.
Oblig. $3647 mill.

Pfd Stock $4116 mill. **Pfd Div'd** $225 mill.

Common Stock 387,150,269 shs.
as of 10/22/24
MARKET CAP: $30.4 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2021	2022	2023
% Change Retail Sales (KWH)	-3.9	+.9	-6.3
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	21190	24345	21254
Annual Load Factor (%)	52.7	45.8	49.7
% Change Customers (yr-end)	+.3	+.8	+.7
Fixed Charge Cov. (%)	113	135	166

ANNUAL RATES of change (per sh)

	Past 10 Yrs.	Past 5 Yrs.	Est'd '21-'23 to '27-'29
Revenues	1.0%	2.5%	*4.5%*
"Cash Flow"	2.0%	5.5%	*5.0%*
Earnings	2.0%	14.0%	*6.5%*
Dividends	8.0%	5.0%	*6.0%*
Book Value	2.0%	.5%	*5.0%*

QUARTERLY REVENUES ($ mill.)

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	2960	3315	5299	3331	14905
2022	3968	4008	5228	4016	17220
2023	3966	3964	4702	3706	16338
2024	4078	4336	5201	***3825***	***17440***
2025	***4400***	***4500***	***5450***	***4050***	***18400***

EARNINGS PER SHARE [A]

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	.79	.94	1.69	1.16	4.59
2022	1.07	.94	1.48	1.15	4.63
2023	1.09	1.01	1.38	1.28	4.76
2024	1.13	1.23	1.51	***1.08***	***4.95***
2025	***1.30***	***1.35***	***1.65***	***1.20***	***5.50***

QUARTERLY DIVIDENDS PAID [B] ■

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	.6625	.6625	.6625	.6625	2.65
2022	.70	.70	.70	.70	2.80
2023	.7375	.7375	.7375	.7375	2.95
2024	.78	.78	.78	.78	3.12
2025	.8275				

BUSINESS: Edison International is a holding company for Southern California Edison Company (SoCal Edison), which supplies electricity to 5.28 mill. customers in a 50,000-sq.-mi. area in central, coastal, & southern CA (excl. Los Angeles & San Diego). Edison Energy is an energy svcs. co. Disc. Edison Mission Energy (independent power producer) in '12. Elec. rev. breakdown: residential, 40%; commercial, 43%; industrial, 3%; other, 14%. Generating sources: nuclear, 9%; gas, 5%; hydroelectric, 6%; purchased, 80%. Power costs: 34% of revs. '23 reported depr. rate: 4.1%. Employs 14,316. Board Chair: Peter J. Taylor. President & CEO: Pedro J. Pizzaro. Inc.: CA. Address: 2244 Walnut Grove Ave., P.O. Box 976, Rosemead, CA 91770. Tel.: 626-302-2222. Internet: www.edison.com.

As this report went to press, shares of Edison International were under significant pressure, as wild fires swept through portions of Los Angeles County. Until very recently, this stock was holding up well in terms of the overall utility group's latest correction. That performance may have been an indication that institutional investors had been warming up to Edison Int'l. As described in the Electric Utility West Industry report, bankruptcy risk is much lower today than it had been a number of years ago. However, if the company's equipment is at fault of causing a major fire or suffers damages from wildfires, the company can still suffer material adverse losses. Having said that, finances have been improving and major legacy wildfire settlements are nearly paid off. Moreover, the company will be allowed to recoup $1.65 billion (60% of the $2.7 billion filed for) related to TKM disaster legacy payouts. It has also filed for a $5.4 billion rate recovery related to the 2018 Woolsey fire.

For a utility, growth prospects are solid. Rising long-term demand for electricity in California is approaching 3% due to trends in electrification for vehicles and heavy equipment, as well as high tech usage. This is well above the national average and leads to transmission and distribution work that pays off rapidly in terms of return on investment for regulated utilities in the state. Fire mitigation also keeps the rate base growing. Edison's current authorized return on equity (ROE) is 10.3%, but may see an improvement by the middle of this year when a general rate case decision is due. State peer PG&E received an authorized ROE of 10.7% from regulators in 2024. Odds are EIX will receive an increase, too. If so, it may be able to grow earnings by 11% in 2025 and 7% per annum for 2025 to 2028.

This equity is untimely. And even though EIX's annual total return prospects through 2027-2029 look good relative to the group, investors must still weigh the wildfire risks involved here. Mitigation has reduced the odds of the company's equipment being at fault for fires, and the California Wildfire Fund has vastly reduced bankruptcy risk, but the company can still suffer material wildfire losses.

Anthony J. Glennon *January 17, 2025*

(A) Adjusted (non-GAAP) EPS from 2019 on. Excl. gains/(losses): nonrecur's ; '10, 54¢; '11, ($3.33); '13, ($1.12); '15, ($1.18); '17, ($1.37); '18, (14¢); '19, (92¢); '20, ($2.54); '21, ($2.59); '22, ($3.02); '23, ($1.34); disc. ops.: '13, 11¢; '14, 57¢; '15, 11¢; '18, 10¢. Qtly. EPS may not sum to full yr. due to rounding. Next egs. report due mid-Feb. **(B)** Div'ds paid late Jan., Apr., July, & Oct. ■ Div'd reinv. plan avail. **(C)** Incl. def'd chgs. In '23: $4.36/sh. **(D)** In mill. **(E)** Rate base: net orig. cost. Rate all'd on com. eq. in '20: 10.3%; Regulatory Climate: Avg.

Company's Financial Strength	A
Stock's Price Stability	90
Price Growth Persistence	20
Earnings Predictability	15

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ENTERGY CORP. NYSE-ETR

RECENT PRICE **152.50** | P/E RATIO **22.9** (Trailing: 18.5 Median: 14.0) | RELATIVE P/E RATIO **1.19** | DIV'D YLD **3.1%** | **VALUE LINE**

TIMELINESS 3 Raised 8/16/24
SAFETY 1 Raised 9/6/24
TECHNICAL 3 Raised 10/25/24
BETA 1.00 (1.00 = Market)

18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$94-$172	$133 (-15%)

2027-29 PROJECTIONS

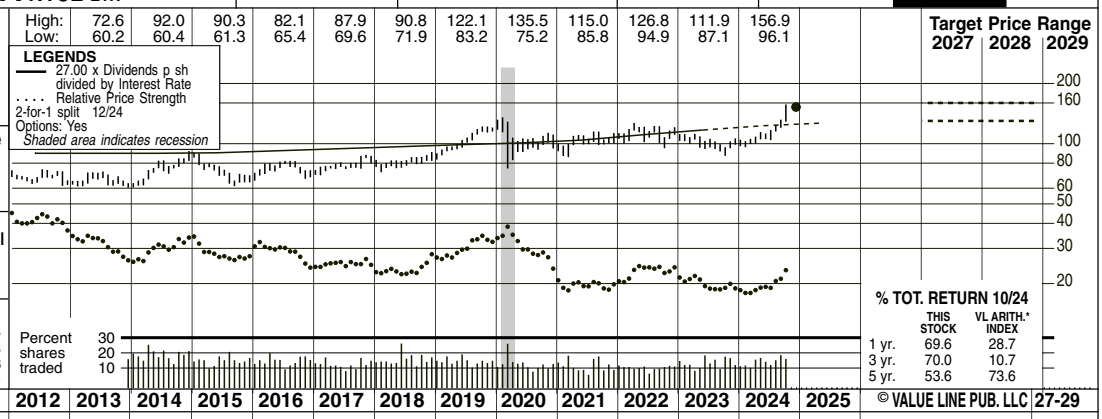
	Price	Gain	Ann'l Total Return
High	160	(+5%)	*4%*
Low	130	(-15%)	*Nil*

Institutional Decisions

	4Q2023	1Q2024	2Q2024
to Buy	429	464	496
to Sell	319	343	333
Hld's(000)	191523	189657	195739

	2027	2028	2029
Target Price Range			

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	© VALUE LINE PUB. LLC	27-29
High:	72.6	92.0	90.3	82.1	87.9	90.8	122.1	135.5	115.0	126.8	111.9	156.9								
Low:	60.2	60.4	61.3	65.4	69.6	71.9	83.2	75.2	85.8	94.9	87.1	96.1								
Revenues per sh	69.15	56.82	64.27	63.67	57.94	63.86	69.71	64.54	60.55	61.35	58.23	54.63	50.51	57.95	65.18	57.07	***56.40***	***59.00***	Revenues per sh	***69.90***
"Cash Flow" per sh	12.89	13.29	16.54	17.53	15.98	16.25	17.68	17.71	18.72	16.70	16.50	17.19	18.21	17.90	15.51	21.53	***16.20***	***18.05***	"Cash Flow" per sh	***21.35***
Earnings per sh [A]	6.20	6.30	6.66	7.55	6.02	4.96	5.77	5.81	6.88	5.19	5.88	6.30	6.90	6.87	5.37	11.10	***4.50***	***6.85***	Earnings per sh [A]	***8.05***
Div'd Decl'd per sh [B] ■ †	3.00	3.00	3.24	3.32	3.32	3.32	3.32	3.34	3.42	3.50	3.58	3.66	3.74	3.86	4.10	4.34	***4.59***	***4.82***	Div'd Decl'd per sh [B] ■ †	***5.20***
Cap'l Spending per sh	13.92	12.99	13.33	15.21	18.18	15.73	14.82	16.79	17.28	22.07	22.45	21.72	24.52	30.86	25.04	20.86	***21.00***	***22.00***	Cap'l Spending per sh	***19.75***
Book Value per sh [C]	42.07	45.54	47.53	50.81	51.73	54.00	55.83	51.89	45.12	44.28	46.78	51.34	54.56	57.42	61.40	68.70	***70.50***	***73.45***	Book Value per sh [C]	***84.65***
Common Shs Outst'g [D]	189.36	189.12	178.75	176.36	177.81	178.37	179.24	178.39	179.13	180.52	189.06	199.15	200.24	202.65	211.18	212.85	***218.00***	***222.00***	Common Shs Outst'g [D]	***230.00***
Avg Ann'l P/E Ratio	16.6	12.0	11.6	9.1	11.2	13.2	12.9	12.5	10.9	15.0	13.8	16.5	15.3	15.0	21.1	9.1	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	***18.0***
Relative P/E Ratio	1.00	.80	.74	.57	.71	.74	.68	.63	.57	.75	.75	.88	.79	.81	1.22	.51			Relative P/E Ratio	***1.00***
Avg Ann'l Div'd Yield	2.9%	4.0%	4.2%	4.9%	4.9%	5.1%	4.5%	4.6%	4.6%	4.5%	4.4%	3.5%	3.6%	3.7%	3.6%	4.3%			Avg Ann'l Div'd Yield	***3.7%***
Revenues ($mill)	12495	11513	10846	11074	11009	10879	10114	11743	13764	12147	***12300***	***13100***	Revenues ($mill)	***16070***
Net Profit ($mill)	1060.0	1061.2	1249.8	950.7	1092.1	1258.2	1406.7	1402.8	1103.2	2356.5	***980***	***1520***	Net Profit ($mill)	***1850***
Income Tax Rate	37.8%	2.2%	11.3%	1.8%	--	--	--	16.1%	16.1%	16.1%	***20.0%***	***23.0%***	Income Tax Rate	***23.0%***
AFUDC % to Net Profit	9.3%	7.4%	8.1%	14.7%	17.5%	16.7%	12.2%	7.1%	2.5%	1.7%	***2.0%***	***2.0%***	AFUDC % to Net Profit	***2.0%***
Long-Term Debt Ratio	54.9%	57.8%	63.6%	63.6%	63.2%	62.0%	65.5%	67.6%	64.2%	60.8%	***61.0%***	***61.0%***	Long-Term Debt Ratio	***61.0%***
Common Equity Ratio	43.8%	40.8%	35.5%	35.5%	35.9%	37.1%	33.7%	31.7%	35.2%	38.6%	***39.0%***	***39.0%***	Common Equity Ratio	***39.0%***
Total Capital ($mill)	22842	22714	22777	22528	24602	27557	32386	36733	36810	37851	***39995***	***42400***	Total Capital ($mill)	***50555***
Net Plant ($mill)	28723	27824	27921	29664	31974	35183	38853	42244	42477	43834	***46465***	***49255***	Net Plant ($mill)	***58660***
Return on Total Cap'l	6.0%	6.0%	6.9%	5.7%	5.8%	5.9%	5.6%	4.9%	4.3%	7.6%	***3.5%***	***4.5%***	Return on Total Cap'l	***5.0%***
Return on Shr. Equity	10.3%	11.1%	15.1%	11.6%	12.0%	12.0%	12.6%	11.8%	8.4%	15.9%	***6.5%***	***9.0%***	Return on Shr. Equity	***9.5%***
Return on Com Equity [E]	10.4%	11.2%	15.2%	11.7%	12.2%	12.1%	12.7%	11.9%	8.4%	16.0%	***6.5%***	***9.0%***	Return on Com Equity [E]	***9.5%***
Retained to Com Eq	4.4%	4.8%	7.7%	3.9%	4.9%	5.2%	5.9%	5.2%	1.9%	9.7%	***NMF***	***3.0%***	Retained to Com Eq	***3.5%***
All Div'ds to Net Prof	58%	58%	50%	68%	61%	58%	55%	57%	78%	40%	***102%***	***70%***	All Div'ds to Net Prof	***65%***



CAPITAL STRUCTURE as of 9/30/24
Total Debt $29002 mill. **Due in 5 Yrs** $11117 mill.
LT Debt $26563 mill. **LT Interest** $1046.0 mill.
Incl. $54.7 mill. of securitization bonds.
(LT interest earned: 2.5x)
Leases, Uncapitalized Annual rentals $67.4 mill.
Pension Assets-12/23 $5469.6 mill.
Oblig $5915.4 mill.
Pfd Stock $219.4 mill. **Pfd Div'd** $18.3 mill.
200,000 shs. 6.25%-7.5%, $100 par; 250,000 shs. 8.75%, 1.4 mill. shs. 5.375%; all cum., without sinking fund.
Common Stock 214,408,014 shs. **as of 9/30/24**
MARKET CAP: $32.7 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2021	2022	2023
% Change Retail Sales (KWH)	+3.2	+1.1	+4.5
Total Indust. Use (GWH)	49819	52501	52807
Avg. Indust. Revs. per KWH(¢)	5.91	7.08	6.00
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+1.0	+1.0	+.4
Fixed Charge Cov. (%)	243	209	250

ANNUAL RATES of change (per sh)

	Past 10 Yrs.	Past 5 Yrs.	Est'd '21-'23 to '27-'29
Revenues	-.5%	--	*2.5%*
"Cash Flow"	1.0%	1.0%	*2.5%*
Earnings	2.5%	5.5%	*.5%*
Dividends	2.0%	3.0%	*3.5%*
Book Value	2.0%	6.5%	*5.0%*

QUARTERLY REVENUES ($ mill.)

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	2845	2822	3353	2723	11743
2022	2878	3395	4219	3273	13764
2023	2981	2846	3596	2725	12147
2024	2795	2954	3389	***3162***	***12300***
2025	***3000***	***3500***	***3400***	***3200***	***13100***

EARNINGS PER SHARE [A]

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	1.66	1.30	2.63	1.28	6.87
2022	1.36	.78	2.74	.51	5.37
2023	1.47	1.84	3.14	4.66	11.10
2024	.35	.23	2.99	***.93***	***4.50***
2025	***1.60***	***1.15***	***3.05***	***1.05***	***6.85***

QUARTERLY DIVIDENDS PAID [B] ■ †

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2020	.93	.93	.93	.95	3.74
2021	.95	.95	.95	1.01	3.86
2022	1.01	1.01	1.01	1.07	4.10
2023	1.07	1.07	1.07	1.13	4.34
2024	1.13	1.13	1.13	1.20	

BUSINESS: Entergy Corporation supplies electricity to 3 million customers through subsidiaries in Arkansas, Louisiana, Mississippi, Texas, and New Orleans (regulated separately from Louisiana). Distributes gas to 206,000 customers in Louisiana. Is selling its last nonutility nuclear unit (shut down 5/22). Electric revenue breakdown: residential, 37%; commercial, 24%; industrial, 27%; other, 12%. Generating sources: gas, 68%; nuclear, 22%; coal, 9%; hydro and solar, 1%. Fuel costs: 32% of revenues. '23 reported depreciation rate: 2.7%. Has 11,707 employees. Chairman & CEO: Leo P. Denault. Incorporated: Delaware. Address: 639 Loyola Avenue, P.O. Box 61000, New Orleans, Louisiana 70161. Telephone: 504-576-4000. Internet: www.entergy.com.

Entergy recorded lackluster 2024 third-quarter results. Revenues fell below $3.4 billion as the company faced some downtime due to a few hurricanes in its service area in the period. This halted operations at several industrial customers, while Entergy faced higher costs related to fixing damaged infrastructure. Absent these problems, better retail sales occurred, and industrial usage continued to grow during the quarter. Additionally, the power generator benefited from lower fuel costs and fewer asset write-downs. Even so, greater interest expenses are due to an expansion of debt, and depreciation increased as the company has continued to build out its supply operations. Overall, these factors netted earnings of $2.99 per share during the quarter.

The company ought to have weaker fourth-quarter results. However, revenues should grow thanks to better usage of its industrial power sources, including the Entergy Arkansas Walnut Bend Solar project, adding around 100-megawatt generation capacity into service. Still, we think that interest costs will rise. These factors will likely cause a decline in profits to $0.93 per share.

We expect positive results over the long haul. The service coverage area has benefited from more demand for power, including amongst its industrial base, as more customers are brought on board. This includes a new deal for a large customer in Louisiana, while the company has $7.0 billion in capital expansion projects, including renewables in its pipeline. Greater industrial activity across Texas and Louisiana should also drive population growth, allowing for greater retail usage. Still, costs will likely rise, and we think an expanding share count should dilute share profits a bit. Even so, we project earnings will rebound to $6.85 in 2025 and $8.05 by 2027-2029.

Shares of Entergy are neutrally ranked for Timeliness. Also, this stock holds lackluster 3- to 5-year appreciation potential, having moved up considerably since our September report. Meanwhile, the company hiked the dividend by 6% to $4.80 annually. Note that the board approved a 2-for-1 stock split on December 13th, not yet reflected in our presentation.

John E. Seibert III *December 6, 2024*

(A) Diluted EPS. GAAP starting in 2022. Excl. nonrec. losses: '12, $1.26; '13, $1.14; '14, 56¢; '15, $6.99; '16, $10.14; '17, $2.91; '18, $1.25; '21, $1.33. Next earnings report due early February. **(B)** Div'ds historically paid in early Mar., June, Sept., & Dec. ■ Div'd reinvestment plan avail. † Shareholder investment plan avail. **(C)** Incl. deferred charges. In '23: $26.66/sh. **(D)** In mill. **(E)** Rate base: Net original cost. Allowed ROE (blended): 9.71%; earned on avg. com. eq., '23: 16.0%. Regulatory Climate: Average.

Company's Financial Strength	A+
Stock's Price Stability	90
Price Growth Persistence	45
Earnings Predictability	70

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EVERGY, INC. NYSE-EVRG

RECENT PRICE 64.49 | P/E RATIO 14.9 (Trailing: 18.5 Median: NMF) | RELATIVE P/E RATIO 0.81 | DIV'D YLD 4.4% | VALUE LINE

TIMELINESS 3 Raised 8/23/24
SAFETY 2 New 9/14/18
TECHNICAL 4 Raised 8/30/24
BETA .95 (1.00 = Market)

18-Month Target Price Range

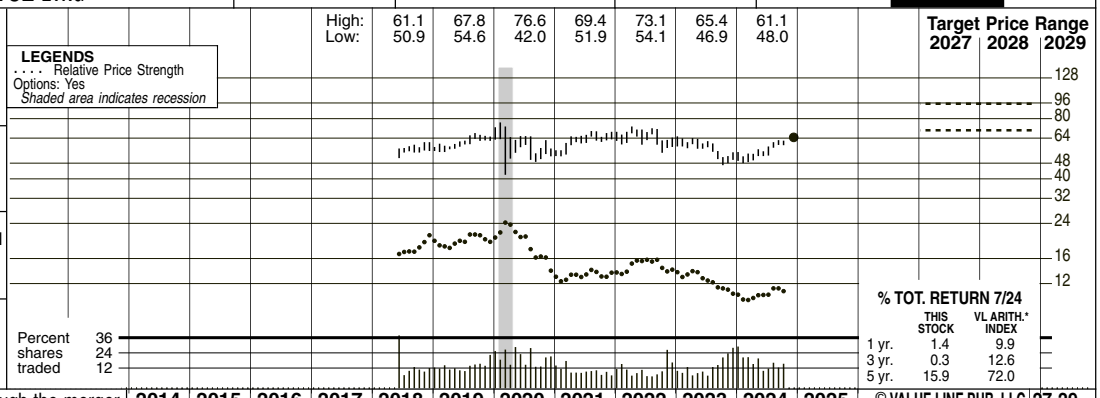
Low-High	Midpoint (% to Mid)
$45-$74	$60 (-10%)

2027-29 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	95	(+60%)	*16%*
Low	70	(+20%)	*9%*

Institutional Decisions

	3Q2023	4Q2023	1Q2024
to Buy	320	357	308
to Sell	273	292	320
Hld's(000)	196134	203440	198283



Evergy, Inc. was formed through the merger of Great Plains Energy and Westar Energy in June of 2018. Great Plains Energy holders received .5981 of a share of Evergy for each of their shares, and Westar Energy holders received one share of Evergy for each of their shares. The merger was completed on June 4, 2018. Shares of Evergy began trading on the New York Stock Exchange one day later.

CAPITAL STRUCTURE as of 9/30/24
Total Debt $11976 mill. **Due in 5 Yrs** $4388 mill.
LT Debt $11571 mill. **LT Interest** $306 mill.
Incl. $40.9 mill. finance leases.
(LT interest earned: 3.8x)

Leases, Uncapitalized Annual rentals $18.8 mill.

Pension Assets-12/22 $1714.7 mill.
Oblig $2561.7 mill.

Pfd Stock None

Common Stock 229,976,171 shs.
MARKET CAP: $13.6 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2020	2021	2022
% Change Retail Sales (KWH)	-3.9	+3.1	+6.7
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	7.14	6.94	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	NA	NA	NA
Fixed Charge Cov. (%)	286	350	382

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '20-'22 to '27-'29
Revenues	--	--	*2.5%*
"Cash Flow"	--	--	*5.0%*
Earnings	--	--	*7.5%*
Dividends	--	--	*7.0%*
Book Value	--	--	*3.5%*

Calendar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	1611.4	1236.7	1616.5	1122.1	5586.7
2022	1223.9	1446.5	1909.1	1279.6	5859.1
2023	1296.8	1354.2	1669.3	1187.9	5508.2
2024	1331.0	1447.5	1811.4	*1210.1*	*5800*
2025	*1350*	*1450*	*1850*	*1350*	*6000*

Calendar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	.84	.81	1.95	.23	3.83
2022	.53	.84	1.86	.03	3.26
2023	.62	.78	1.53	.24	3.17
2024	.53	.90	2.02	*.40*	*3.85*
2025	*.65*	*.95*	*1.95*	*.50*	*4.05*

Calendar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2020	.505	.505	.505	.535	2.05
2021	.535	.535	.535	.5725	2.18
2022	.5725	.5725	.5725	.6125	2.33
2023	.6125	.6125	.6125	.6425	2.48
2024	.6425	.6425	.6425	.6675	

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	© VALUE LINE PUB. LLC	27-29
Revenues per sh	--	--	--	--	16.75	22.71	21.66	24.36	25.49	23.98	*25.20*	*26.10*		*29.55*
"Cash Flow" per sh	--	--	--	--	4.89	7.18	7.06	8.18	7.34	8.33	*8.20*	*8.55*		*9.35*
Earnings per sh A	--	--	--	--	2.50	2.79	2.72	3.83	3.26	3.17	*3.85*	*4.05*		*4.75*
Div'd Decl'd per sh B ■	--	--	--	--	1.74	1.93	2.05	2.18	2.33	2.48	*2.61*	*2.74*		*3.05*
Cap'l Spending per sh	--	--	--	--	4.19	5.34	6.88	8.60	9.41	9.23	*9.25*	*9.30*		*9.50*
Book Value per sh C	--	--	--	--	39.28	37.82	38.50	40.32	41.86	42.06	*44.10*	*45.65*		*47.50*
Common Shs Outst'g D	--	--	--	--	255.33	226.64	226.84	229.30	229.90	229.73	*230.00*	*230.00*		*230.00*
Avg Ann'l P/E Ratio	--	--	--	--	22.7	21.8	21.7	16.2	19.9	18.0	*Bold figures are Value Line estimates*			*17.5*
Relative P/E Ratio	--	--	--	--	1.23	1.16	1.11	.88	1.15	1.01				*.95*
Avg Ann'l Div'd Yield	--	--	--	--	3.1%	3.2%	3.5%	3.5%	4.0%	5.1%				*3.7%*
Revenues ($mill)	--	--	--	--	4275.9	5147.8	4913.4	5586.7	5859.1	5508.2	*5800*	*6000*		*6800*
Net Profit ($mill)	--	--	--	--	535.8	669.9	618.3	879.7	752.7	731.3	*885*	*930*		*1090*
Income Tax Rate	--	--	--	--	9.8%	12.6%	14.1%	11.7%	5.8%	2.1%	*4.5%*	*6.5%*		*9.0%*
AFUDC % to Net Profit	--	--	--	--	2.5%	2.5%	5.5%	5.0%	5.1%	5.4%	*6.0%*	*6.0%*		*5.0%*
Long-Term Debt Ratio	--	--	--	--	40.0%	50.6%	51.3%	50.1%	50.0%	51.5%	*51.5%*	*52.0%*		*53.5%*
Common Equity Ratio	--	--	--	--	60.0%	49.4%	48.7%	49.9%	48.0%	48.0%	*48.5%*	*48.0%*		*46.5%*
Total Capital ($mill)	--	--	--	--	16716	17337	17924	18542	19668	20019	*21250*	*22500*		*23400*
Net Plant ($mill)	--	--	--	--	18952	19346	20106	21150	22277	23729	*24200*	*25300*		*26300*
Return on Total Cap'l	--	--	--	--	4.0%	4.8%	4.5%	5.7%	6.9%	6.4%	*5.5%*	*5.5%*		*6.0%*
Return on Shr. Equity	--	--	--	--	5.3%	7.8%	7.1%	9.5%	8.1%	7.6%	*9.0%*	*9.0%*		*10.0%*
Return on Com Equity E	--	--	--	--	5.3%	7.8%	7.1%	9.5%	8.1%	7.6%	*9.0%*	*9.0%*		*10.0%*
Retained to Com Eq	--	--	--	--	.6%	2.4%	1.8%	4.1%	3.1%	2.5%	*3.0%*	*3.0%*		*3.5%*
All Div'ds to Net Prof	--	--	--	--	89%	69%	75%	57%	73%	69%	*68%*	*68%*		*63%*

BUSINESS: Evergy, Inc. was formed through the merger of Great Plains Energy and Westar Energy in June of 2018. Through its subsidiaries (now doing business under the Evergy name), provides electric service to 1.6 million customers in Kansas and Missouri, including the greater Kansas City area. Electric revenue breakdown: residential, 32%; commercial, 27%; industrial, 15%; wholesale, 13%; other, 13%. Generating sources: coal, 54%; nuclear, 17%; purchased, 29%. Fuel costs: 28% of revenues. '23 reported deprec. rate: 3%. Has 4,900 employees. Chairman: Mark A. Ruelle. President & CEO: David A. Campbell. COO: Kevin E. Bryant. Inc.: Missouri. Address: 1200 Main Street, Kansas City, Missouri 64105. Tel.: 816-556-2200. Internet: www.evergy.com.

Evergy looks set to post significantly higher profits in 2024. Indeed, the utility recorded better-than-expected third-quarter results. Revenues of $1.81 billion and earnings of $2.02 a share both surpassed our estimates and improved substantially from the year-prior period. An increased number of cooling days, along with new retail rates and transmission investments were the primary drivers of the strong showing. Management reaffirmed its 2024 bottom-line target range of $3.73-$3.93 per share. Our unchanged estimate sits near the middle of this range. And, the stock price has risen nicely over the past three months. Indeed, these shares are up more than 10% in value over that interim, and have jumped nearly 30% in the past year.

Our full-year 2025 earnings estimate is staying put at $4.05 a share. We expect slower growth compared to 2024, but our estimates are still within Evergy's long-term annual adjusted share-earnings growth target. Indeed, we look for a 5% increase from our 2024 estimate, which is right in the middle of management's updated 4%-6% yearly profit growth target. The company will likely take advantage of elevated power demand due to data centers and AI innovations, along with regulatory and rate improvements.

The board of directors raised the quarterly dividend, effective with the December payout. The increase was $0.025 a share (4%). The utility's target for the payout ratio is a range of 60%-70%. The yield of 4.4% stands comfortably above the utility average, which is one of the highest dividend-paying industries in the market.

These shares are best suited for conservative, income-oriented accounts. The aforementioned recently raised yield is Evergy's most notable feature. Long-term total return potential remains decent, on a risk-adjusted basis, in comparison to most of its peers, despite the recent stock price increase. We continue to look for the stock to trade around $70-$95 by 2027-2029, and think the company will earn $4.75 a share by then, which has been raised by $0.05 a share. Meanwhile, the stock is ranked to mirror the broader market averages in the year ahead.

Zachary J. Hodgkinson December 6, 2024

(A) Diluted earnings. Next earnings report due late Feb. **(B)** Dividends paid in mid-March, June, September, and December. ■ Dividend reinvestment plan available. **(C)** Incl. intangibles. **(D)** In millions. **(E)** Rate base: Original cost depreciated. Rate allowed on common equity in Missouri in '18: none specified; in Kansas in '18: 9.3%; earned on average common equity, '22: 9.8%. Regulatory Climate: Average.

Company's Financial Strength	B++
Stock's Price Stability	90
Price Growth Persistence	25
Earnings Predictability	85

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IDACORP, INC. NYSE-IDA

RECENT PRICE **107.52** | P/E RATIO **19.1** (Trailing: 19.9 Median: 20.0) | RELATIVE P/E RATIO **1.06** | DIV'D YLD **3.2%** | **VALUE LINE**

TIMELINESS 4 Raised 8/16/24
SAFETY 1 Raised 4/19/24
TECHNICAL 1 Raised 1/3/25
BETA .85 (1.00 = Market)

18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$89-$128	$109 (5%)

2027-29 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	150	(+40%)	*11%*
Low	120	(+10%)	*6%*

Institutional Decisions

	1Q2024	2Q2024	3Q2024
to Buy	165	191	226
to Sell	200	170	166
Hld's(000)	46315	46039	51027

	High:	54.7	70.1	70.5	83.4	100.0	102.4	114.0	113.6	113.8	118.9	113.0	120.4
	Low:	43.1	50.2	55.4	65.0	77.5	79.6	89.3	69.1	85.3	93.5	88.1	86.4

LEGENDS
30.30 x Dividends p sh
Relative Price Strength
Options: Yes
Shaded area indicates recession

Target Price Range 2027 2028 2029

200 160 100 80 60 50 40 30 20

Percent shares traded 15 10 5

% TOT. RETURN 12/24

	THIS STOCK	VL ARITH.* INDEX
1 yr.	16.1	13.6
3 yr.	6.9	14.7
5 yr.	19.4	70.9

2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	© VALUE LINE PUB. LLC	27-29
20.47	21.92	20.97	20.55	21.55	24.81	25.51	25.23	25.04	26.76	27.19	26.70	26.77	28.86	32.51	34.90	*35.05*	*36.75*	Revenues per sh	*39.90*
4.27	5.07	5.35	5.84	5.93	6.29	6.58	6.70	6.86	7.50	7.85	8.07	8.19	8.41	8.55	9.11	*9.50*	*10.20*	"Cash Flow" per sh	*12.25*
2.18	2.64	2.95	3.36	3.37	3.64	3.85	3.87	3.94	4.21	4.49	4.61	4.69	4.85	5.11	5.14	*5.45*	*5.80*	Earnings per sh [A]	*7.10*
1.20	1.20	1.20	1.20	1.37	1.57	1.76	1.92	2.08	2.24	2.40	2.56	2.72	2.88	3.04	3.20	3.35	*3.52*	Div'd Decl'd per sh [B] ■ †	*4.20*
5.19	5.26	6.85	6.76	4.78	4.68	5.45	5.84	5.89	5.66	5.51	5.53	6.16	5.94	8.56	12.07	*17.75*	*16.60*	Cap'l Spending per sh	*13.40*
27.76	29.17	31.01	33.19	35.07	36.84	38.85	40.88	42.74	44.65	47.01	48.88	50.73	52.82	55.52	57.44	*63.55*	*66.60*	Book Value per sh [C]	*71.50*
46.92	47.90	49.41	49.95	50.16	50.23	50.27	50.34	50.40	50.42	50.42	50.42	50.46	50.52	50.56	50.62	*53.50*	*54.00*	Common Shs Outst'g [D]	*56.00*
13.9	10.2	11.8	11.5	12.4	13.4	14.7	16.2	19.1	20.6	20.5	22.3	19.9	20.8	21.0	19.9	*18.0*		Avg Ann'l P/E Ratio	*19.0*
.84	.68	.75	.72	.79	.75	.77	.82	1.00	1.04	1.11	1.19	1.02	1.12	1.21	1.11	*.65*		Relative P/E Ratio	*1.05*
4.0%	4.5%	3.4%	3.1%	3.3%	3.2%	3.1%	3.1%	2.8%	2.6%	2.6%	2.5%	2.9%	2.9%	2.8%	3.1%	3.4%		Avg Ann'l Div'd Yield	*3.1%*
1282.5	1270.3	1262.0	1349.5	1370.8	1346.4	1350.7	1458.1	1644.0	1766.4	*1875*	*1985*	Revenues ($mill)	*2235*
193.5	194.7	198.3	212.4	226.8	232.9	237.4	245.6	259.0	261.2	*290*	*315*	Net Profit ($mill)	*400*
8.0%	19.0%	15.5%	18.6%	7.1%	9.5%	10.8%	13.1%	12.7%	9.4%	*13.0%*	*13.0%*	Income Tax Rate	*13.0%*
13.6%	16.3%	16.3%	13.9%	15.2%	16.2%	17.3%	17.7%	19.8%	8.8%	*15.0%*	*15.0%*	AFUDC % to Net Profit	*16.0%*
45.3%	45.6%	44.8%	43.7%	43.6%	41.3%	43.9%	42.8%	43.9%	48.8%	*48.5%*	*49.0%*	Long-Term Debt Ratio	*49.5%*
54.7%	54.4%	55.2%	56.3%	56.4%	58.7%	56.1%	57.2%	56.1%	51.2%	*51.5%*	*51.0%*	Common Equity Ratio	*50.5%*
3567.6	3783.3	3898.5	3997.5	4205.1	4201.3	4560.4	4669.1	5001.4	5683.4	*6200*	*6625*	Total Capital ($mill)	*7500*
3833.5	3992.4	4172.0	4283.9	4395.7	4531.5	4709.5	4901.8	5173.0	5745.2	*6350*	*6775*	Net Plant ($mill)	*7600*
6.6%	6.2%	6.1%	6.3%	6.4%	6.5%	6.1%	6.2%	6.1%	5.4%	*5.5%*	*6.0%*	Return on Total Cap'l	*6.0%*
9.9%	9.5%	9.2%	9.4%	9.6%	9.4%	9.3%	9.2%	9.2%	9.0%	*9.0%*	*9.0%*	Return on Shr. Equity	*9.0%*
9.9%	9.5%	9.2%	9.4%	9.6%	9.4%	9.3%	9.2%	9.2%	9.0%	*9.0%*	*9.0%*	Return on Com Equity [E]	*9.0%*
5.4%	4.8%	4.3%	4.4%	4.4%	4.2%	3.9%	3.7%	3.7%	3.4%	*3.5%*	*3.5%*	Retained to Com Eq	*3.5%*
46%	50%	53%	53%	54%	56%	58%	60%	60%	63%	*62%*	*61%*	All Div'ds to Net Prof	*59%*

CAPITAL STRUCTURE as of 9/30/24
Total Debt $3123.7 mill. **Due in 5 Yrs** $200.0 mill.
LT Debt $3054.0 mill. **LT Interest** $140.0 mill.
(Total Interest Coverage: 2.5x)

Pension Assets-12/23 $917.5 mill.
Oblig $1028.0 mill.

Pfd Stock None

Common Stock 53,269,814 shs.
as of 10/25/24

MARKET CAP: $5.7 billion (Mid Cap)

ELECTRIC OPERATING STATISTICS

	2021	2022	2023
% Change Retail Sales (KWH)	+3.9	+9.6	+7.3
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	3751	3568	3615
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+2.8	+2.4	+2.4
Fixed Charge Cov. (%)	390	395	315

ANNUAL RATES of change (per sh)

	Past 10 Yrs.	Past 5 Yrs.	Est'd '21-'23 to '27-'29
Revenues	3.5%	4.0%	*3.5%*
"Cash Flow"	3.5%	3.5%	*6.0%*
Earnings	4.0%	3.5%	*6.0%*
Dividends	8.0%	6.5%	*5.5%*
Book Value	4.5%	4.5%	*4.5%*

QUARTERLY REVENUES($ mill.)

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	316.1	360.1	446.9	335.0	1458.1
2022	344.3	358.7	518.0	422.9	1644.0
2023	429.7	413.8	510.9	412.0	1766.4
2024	448.1	451.0	528.5	***447.4***	***1875***
2025	***475***	***475***	***585***	***450***	***1985***

EARNINGS PER SHARE [A]

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	.89	1.38	1.93	.65	4.85
2022	.91	1.27	2.10	.83	5.11
2023	1.11	1.35	2.07	.61	5.14
2024	.95	1.71	2.12	***.67***	***5.45***
2025	***1.05***	***1.80***	***2.25***	***.70***	***5.80***

QUARTERLY DIVIDENDS PAID [B] ■ †

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	.71	.71	.71	.75	2.88
2022	.75	.75	.75	.79	3.04
2023	.79	.79	.79	.83	3.20
2024	.83	.83	.83	.86	3.35
2025					

BUSINESS: IDACORP, Inc. is a holding company for Idaho Power Company, a regulated electric utility that serves 633,000 customers throughout a 24,000-square-mile area in southern Idaho and eastern Oregon (population: 1.4 million). Most of the company's revenues are derived from the Idaho portion of its service area. Revenue breakdown: residential, 39%; commercial, 21%; industrial, 14%; irrigation, 10%; other, 16%. Generating sources: hydro, 35%; coal, 13%; gas, 15%; purchased, 37%. Fuel costs: 40% of revenues. '23 reported depreciation rate: 3.1%. Has 2,112 employees. Chairman: Dennis L. Johnson. President & CEO: Lisa Grow. Incorporated: Idaho. Address: 1221 W. Idaho St., Boise, Idaho 83702. Telephone: 208-388-2200. Internet: www.idacorpinc.com.

IDACORP has performed well over the first nine months of 2024. The utility company saw a 5% year-over-year increase in its top line and approximately 6% growth in the bottom line. A rise in Idaho base rates, significant customer growth, and higher customer usage due to warmer weather partially offset the impact of increased depreciation and interest expenses. Some of these costs were tied to IDACORP's ongoing infrastructure expansion efforts (more below).

The near-term profit picture appears healthy. Given the utility's recent performance, management has raised the lower end of its anticipated share earnings to the $5.35-$5.45 range, up from the previous $5.30-$5.45 forecast. Key assumptions in this projection include Idaho Power, its subsidiary, expecting additional tax credits of $25 million to $35 million, as well as normal weather trends. Additionally, rate increases requested by the company took effect on January 1, 2025. We believe the utility has strong prospects for both top- and bottom-line growth in the near term, despite the elevated costs related to infrastructure. Therefore, we estimate IDACORP to have ended 2024 with a 6% increase in full-year share profit, to $5.45. In 2025, the bottom line will likely continue to grow at a similar pace, reaching $5.80 per share.

IDACORP has a long-term capital expenditure plan in place. The company intends to invest $1 billion to $1.1 billion in 2025, $3.5 billion to $4.0 billion in 2026, and $3.5 billion to $4.0 billion from 2027 to 2028. This plan will help IDACORP meet demand and maintain affordable prices for its customers. Utility companies have incentives to pursue capital projects, which can support future rate-base negotiations.

The board raised the fourth-quarter dividend. The new payment of $0.86 per share, made in December, represents a 3.6% increase over the previous-year tally.

Shares of IDACORP are ranked to underperform the broader market averages in the year ahead (Timeliness: 4). Plus, the stock has a subpar dividend yield for a utility. Also, these shares do not stand out for 18-month capital gains potential.

Emma Jalees *January 17, 2025*

(A) Diluted EPS. Earnings may not sum due to rounding. Next earnings report due early February. **(B)** Dividends historically paid in late February, May, August, and November. ■ Dividend reinvestment plan available. † Shareholder investment plan available. **(C)** Incl. intangibles. In '23: $882.7 mill., $17.44/sh. **(D)** In millions. **(E)** Rate base: Net original cost. Rate allowed on common equity in '12: 10% (imputed); Regulatory Climate: Above Average.

Company's Financial Strength	A
Stock's Price Stability	95
Price Growth Persistence	45
Earnings Predictability	100

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NORTHWESTERN NDQ-NWE

RECENT PRICE **51.68** | P/E RATIO **14.7** (Trailing: 14.0 Median: 17.0) | RELATIVE P/E RATIO **0.81** | DIV'D YLD **5.1%** | **VALUE LINE**

TIMELINESS 3 Lowered 5/24/24
SAFETY 2 Raised 10/18/24
TECHNICAL 2 Raised 12/27/24
BETA 1.00 (1.00 = Market)

18-Month Target Price Range

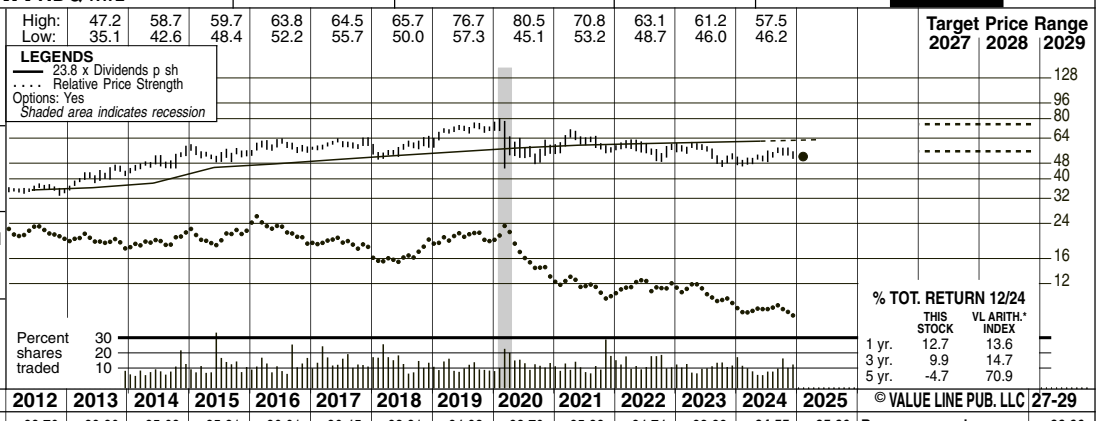
Low-High	Midpoint (% to Mid)
$41-$63	$52 (-5%)

2027-29 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	75	(+45%)	*13%*
Low	55	(+5%)	*6%*

Institutional Decisions

	1Q2024	2Q2024	3Q2024
to Buy	168	158	160
to Sell	128	134	139
Hld's(000)	58166	58903	67655



2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	© VALUE LINE PUB. LLC	27-29
35.09	31.72	30.66	30.80	28.76	29.80	25.68	25.21	26.01	26.45	23.81	24.93	23.70	25.38	24.74	23.22	*24.55*	*25.80*	Revenues per sh	*28.90*
4.40	4.62	4.76	5.42	5.18	5.45	5.39	5.92	6.74	6.76	6.96	7.07	6.86	6.92	6.46	6.69	*7.00*	*7.45*	"Cash Flow" per sh	*8.55*
1.77	2.02	2.14	2.53	2.26	2.46	2.99	2.90	3.39	3.34	3.40	3.53	3.21	3.50	3.29	3.22	*3.40*	*3.70*	Earnings per sh A	*4.25*
1.32	1.34	1.36	1.44	1.48	1.52	1.60	1.92	2.00	2.10	2.20	2.30	2.40	2.48	2.52	2.56	2.60	*2.64*	Div'd Decl'd per sh B ■ †	*2.76*
3.47	5.26	6.30	5.20	5.89	5.95	5.76	5.89	5.96	5.60	5.64	6.26	8.02	8.03	8.62	9.26	*8.15*	*8.15*	Cap'l Spending per sh	*8.25*
21.25	21.86	22.64	23.68	25.09	26.60	31.50	33.22	34.68	36.44	38.60	40.42	41.10	43.28	44.61	45.48	*46.35*	*47.50*	Book Value per sh C	*51.85*
35.93	36.00	36.23	36.28	37.22	38.75	46.91	48.17	48.33	49.37	50.32	50.45	50.59	54.06	59.74	61.25	*61.50*	*62.00*	Common Shs Outst'g D	*64.00*
13.9	11.5	12.9	12.6	15.7	16.9	16.2	18.4	17.2	17.8	16.8	19.9	18.6	17.4	17.3	17.0	*15.2*		Avg Ann'l P/E Ratio	*15.5*
.84	.77	.82	.79	1.00	.95	.85	.93	.90	.90	.91	1.06	.96	.94	1.00	.95	*.84*		Relative P/E Ratio	*.85*
5.4%	5.7%	4.9%	4.5%	4.2%	3.7%	3.3%	3.6%	3.4%	3.5%	3.9%	3.3%	4.0%	4.1%	4.4%	4.7%	5.0%		Avg Ann'l Div'd Yield	*4.2%*
1204.9	1214.3	1257.2	1305.7	1198.1	1257.9	1198.7	1372.3	1477.8	1422.1	*1510*	*1600*	Revenues ($mill)	*1850*
120.7	138.4	164.2	162.7	171.1	179.3	162.6	181.6	185.5	194.1	*210*	*230*	Net Profit ($mill)	*270*
- -	13.7%	- -	7.6%	- -	1.6%	- -	.9%	.9%	3.7%	*6.0%*	*9.0%*	Income Tax Rate	*12.0%*
8.9%	9.8%	4.3%	5.2%	3.4%	4.6%	6.0%	14.9%	18.5%	21.6%	*20.5%*	*20.0%*	AFUDC % to Net Profit	*20.0%*
53.4%	53.1%	52.0%	50.2%	52.2%	52.5%	52.8%	52.2%	48.2%	49.1%	*50.0%*	*51.0%*	Long-Term Debt Ratio	*50.5%*
46.6%	46.9%	48.0%	49.8%	47.8%	47.5%	47.2%	47.8%	51.8%	50.9%	*50.0%*	*49.0%*	Common Equity Ratio	*49.5%*
3168.0	3408.6	3493.9	3614.5	4064.6	4289.8	4409.1	4893.1	5148.3	5475.4	*5725*	*5975*	Total Capital ($mill)	*6700*
3758.0	4059.5	4214.9	4358.3	4521.3	4700.9	4952.9	5247.2	5657.5	6039.8	*6300*	*6600*	Net Plant ($mill)	*7300*
4.8%	5.2%	5.9%	5.6%	5.2%	5.2%	4.6%	4.6%	4.5%	4.5%	*4.5%*	*5.0%*	Return on Total Cap'l	*5.0%*
8.2%	8.6%	9.8%	9.0%	8.8%	8.8%	7.8%	7.8%	7.0%	7.0%	*7.5%*	*8.0%*	Return on Shr. Equity	*8.0%*
8.2%	8.6%	9.8%	9.0%	8.8%	8.8%	7.8%	7.8%	7.0%	7.0%	*7.5%*	*8.0%*	Return on Com Equity E	*8.0%*
3.8%	3.0%	4.1%	3.4%	3.2%	3.1%	2.0%	2.3%	1.7%	1.4%	*2.0%*	*2.5%*	Retained to Com Eq	*3.0%*
54%	65%	58%	62%	64%	64%	74%	71%	76%	79%	*76%*	*71%*	All Div'ds to Net Prof	*65%*

CAPITAL STRUCTURE as of 9/30/24
Total Debt $2974.1 mill. **Due in 5 Yrs** $1011.5 mill.
LT Debt $2570.7 mill. **LT Interest** $115.0 mill.
Incl. $2.8 mill. finance leases.
(Total Interest Coverage: 2.6x)

Pension Assets-12/23 $402.7 mill.
Oblig $477.0 mill.

Pfd Stock None

Common Stock 61,314,217 shs.
as of 10/25/24

MARKET CAP: $3.4 billion (Mid Cap)

ELECTRIC OPERATING STATISTICS

	2021	2022	2023
% Change Retail Sales (KWH)	+.7	+3.7	-.3
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Winter (Mw)	2000	2073	1992
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+1.6	+1.5	+1.6
Fixed Charge Cov. (%)	245	219	216

ANNUAL RATES of change (per sh)

	Past 10 Yrs.	Past 5 Yrs.	Est'd '21-'23 to '27-'29
Revenues	-2.0%	-1.0%	*2.5%*
"Cash Flow"	2.5%	-.5%	*3.5%*
Earnings	3.5%	- -	*4.5%*
Dividends	5.5%	3.5%	*1.5%*
Book Value	6.0%	4.0%	*3.0%*

QUARTERLY REVENUES ($ mill.)

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	400.8	298.2	326.0	347.3	1372.3
2022	394.5	323.0	335.1	425.2	1477.8
2023	454.5	290.5	321.1	356.0	1422.1
2024	475.3	319.9	345.2	*369.6*	*1510*
2025	*490*	*330*	*375*	*405*	*1600*

EARNINGS PER SHARE A

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	1.24	.59	.70	.97	3.50
2022	1.08	.58	.47	1.16	3.29
2023	1.10	.32	.48	1.32	3.22
2024	1.08	.52	.64	*1.16*	*3.40*
2025	*1.18*	*.54*	*.69*	*1.29*	*3.70*

QUARTERLY DIVIDENDS PAID B ■ †

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	.62	.62	.62	.62	2.48
2022	.63	.63	.63	.63	2.52
2023	.64	.64	.64	.64	2.56
2024	.65	.65	.65	.65	2.60
2025					

BUSINESS: NorthWestern Energy Group, Inc. supplies electricity & gas in the Upper Midwest and Northwest, serving 467,700 electric customers in Montana and South Dakota and 307,600 gas customers in Montana, South Dakota, and Nebraska. Electric revenue breakdown for 2023: residential, 44%; commercial, 50%; industrial, 4%; and other, 2%. Generating sources: coal, 18%; hydro, 37%; wind, 4%; natural gas, 12%; purchased power, 29%. Fuel costs: 30% of revenues. 2023 reported depreciation rate: 2.8%. Had 1,573 employees as of 12/31/23. Chair of the board of directors: Dana J. Dykhouse. President and CEO: Brian B. Bird. Incorporated: DE. Address: 3010 West 69th Street, Sioux Falls, SD 57108. Telephone: 605-978-2900. Internet: www.northwesternenergy.com.

NorthWestern Energy's 2024 earnings per share were likely lower than we previously expected. While rate relief from the October 2023 general rate case (GRC) decision in Montana was a major plus last year, milder-than-typical weather crimped electricity and natural gas demand in the company's service territory. NorthWestern had also counted on receiving higher interim rates ahead of its next Montana GRC as it had in the last major state regulatory decision. Interim rate relief was delayed and as a result, management revised its share-earnings target range lower to $3.32-$3.47 from the initial $3.42-$3.62 outlook. The company is due to report year-end results after the market closes on February 14th.

NorthWestern is once again due for major rate relief. The public hearing for the GRC, which was filed last year, is scheduled to begin on April 22nd, with a final decision projected to conclude by year's end. It's unclear if interim rates will be forthcoming. In the utility's application to the Montana Public Service Commission, it requested a more than one percentage point hike to its authorized return on equity (ROE), to 10.8% for both natural gas and electric investments. The company is also seeking a $164 million annual revenue increase from electricity customers and $29 million from gas customers. A significant portion of the hike is associated with infrastructure the company has paid for, but not yet billed for. This includes utility poles, pipelines, and a 175-megawatt natural gas generation plant that was delayed and over budget, in part due to it being contested by environmentalist groups. The company said the final cost on the project was about $315 million, up from the budgeted $275 million. Our expectation is that NWE will get much of, but certainly not all of, what it's asking for. We'd be surprised if the ROE is significantly raised.

Income-oriented accounts might find these shares of interest. The 5.1% yield is well above the median 3.7% for electric utilities. We don't see much appreciation potential. And, it will likely take years for the dividend payout ratio to drop enough to allow for growth in the annual payout to match share-earnings gains.

Anthony J. Glennon *January 17, 2025*

(A) Diluted egs. Excl. nonrec. gains/(losses): '12, 40¢; '15, 27¢; '18, 52¢; '19, 45¢; '20, (15¢); '21, 10¢; '22, (4¢). Qtly EPS may not sum to full yr. due to rounding. Next egs. report due February 14th. **(B)** Div'ds paid late Mar., June, Sept. & Dec. ■ Div'd reinvest. plan avail. † Shrhldr. invest. plan avail. **(C)** Incl. def'd charges and intag. '23: $17.90/sh. **(D)** In mill. **(E)** Rate base: Net orig. cost. Rate allowed on com. eq. in MT in '23 (elec.): 9.65%; in '23 (gas): 9.55%; in SD in '24: 6.81%; in NE in '07: 10.4%. Reg. Climate: Below Avg.

Company's Financial Strength	B++
Stock's Price Stability	90
Price Growth Persistence	15
Earnings Predictability	95

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OGE ENERGY CORP. NYSE-OGE

RECENT PRICE **39.64** | P/E RATIO **16.1** (Trailing: 19.4 Median: 18.0) | RELATIVE P/E RATIO **0.88** | DIV'D YLD **4.3%** | **VALUE LINE**

TIMELINESS 4 Raised 8/23/24
SAFETY 3 Lowered 3/8/24
TECHNICAL 3 Raised 8/30/24
BETA 1.05 (1.00 = Market)

18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$28-$45	$37 (-10%)

2027-29 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	45	(+15%)	*7%*
Low	30	(-25%)	*-2%*

Institutional Decisions

	3Q2023	4Q2023	1Q2024
to Buy	197	210	215
to Sell	199	206	218
Hld's(000)	138173	144477	139254

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	© VALUE LINE PUB. LLC	27-29
High:	40.0	39.3	36.5	34.2	37.4	41.8	45.8	46.4	38.6	42.9	40.4	40.4								
Low:	27.7	32.8	24.2	23.4	32.6	29.6	38.0	23.0	29.2	33.3	31.3	32.1								
	21.77	14.79	19.04	19.96	18.58	14.45	12.30	11.00	11.31	11.32	11.37	11.15	10.61	18.26	16.86	13.36	***14.50***	***15.00***	Revenues per sh	***17.50***
	2.40	2.69	3.01	3.31	3.69	3.46	3.40	3.23	3.31	3.34	3.74	4.02	4.03	4.44	5.63	4.61	***4.75***	***5.05***	"Cash Flow" per sh	***5.85***
	1.25	1.33	1.50	1.73	1.79	1.94	1.98	1.69	1.69	1.92	2.12	2.24	2.08	2.36	2.25	2.07	***2.15***	***2.30***	Earnings per sh A	***2.70***
	.70	.71	.73	.76	.80	.85	.95	1.05	1.16	1.27	1.40	1.51	1.58	1.63	1.64	1.66	***1.69***	***1.73***	Div'd Decl'd per sh B ■	***1.85***
	4.01	4.37	4.36	6.48	5.85	4.99	2.86	2.74	3.31	4.13	2.87	3.18	3.25	3.89	5.25	4.49	***4.75***	***4.75***	Cap'l Spending per sh	***4.75***
	10.14	10.52	11.73	13.06	14.00	15.30	16.27	16.66	17.24	19.28	20.06	20.69	18.15	20.27	22.52	22.17	***23.10***	***23.75***	Book Value per sh C	***26.25***
	187.00	194.00	195.20	196.20	197.60	198.50	199.40	199.70	199.70	199.70	199.70	200.10	200.10	200.10	200.20	200.30	***200.20***	***200.20***	Common Shs Outst'g D	***200.20***
	12.4	10.8	13.3	14.4	15.2	17.7	18.3	17.7	17.7	18.3	16.5	19.0	16.2	14.3	17.2	17.4	***Bold figures are***		Avg Ann'l P/E Ratio	***14.0***
	.75	.72	.85	.90	.97	.99	.96	.89	.93	.92	.89	1.01	.83	.77	1.00	.96	***Value Line***		Relative P/E Ratio	***.80***
	4.5%	5.0%	3.7%	3.1%	2.9%	2.5%	2.6%	3.5%	3.9%	3.6%	4.0%	3.5%	4.7%	4.8%	4.5%	5.1%	***estimates***		Avg Ann'l Div'd Yield	***4.4%***
							2453.1	2196.9	2259.2	2261.1	2270.3	2231.6	2122.3	3653.7	3375.7	2674.3	***2900***	***3000***	Revenues ($mill)	***3500***
							395.8	337.6	338.2	384.3	425.5	449.6	415.9	472.5	665.7	416.8	***430***	***460***	Net Profit ($mill)	***540***
							30.4%	29.2%	30.5%	32.5%	14.5%	7.4%	13.2%	11.5%	12.0%	12.0%	***12.0%***	***12.0%***	Income Tax Rate	***12.0%***
							1.7%	3.7%	6.4%	15.0%	8.3%	1.6%	1.6%	2.2%	2.0%	2.0%	***2.0%***	***2.0%***	AFUDC % to Net Profit	***2.0%***
							45.9%	44.3%	41.1%	41.7%	42.0%	43.6%	49.0%	52.6%	49.8%	51.2%	***52.0%***	***51.5%***	Long-Term Debt Ratio	***50.0%***
							54.1%	55.7%	58.9%	58.3%	58.0%	56.4%	51.0%	47.4%	52.4%	49.6%	***48.0%***	***48.5%***	Common Equity Ratio	***50.0%***
							5999.7	5971.6	5849.6	6600.7	6902.0	7334.7	7126.2	8552.7	8962.0	9238.2	***9750***	***9935***	Total Capital ($mill)	***10400***
							6979.9	7322.4	7696.2	8339.9	8643.8	9044.6	9374.6	9832.9	10546.8	11301.0	***11000***	***11250***	Net Plant ($mill)	***12075***
							7.8%	6.9%	7.0%	7.0%	7.3%	7.1%	6.9%	6.4%	5.9%	6.3%	***7.0%***	***7.0%***	Return on Total Cap'l	***7.5%***
							12.2%	10.2%	9.8%	10.0%	10.6%	10.9%	11.5%	11.6%	11.0%	12.0%	***12.5%***	***12.5%***	Return on Shr. Equity	***13.0%***
							12.2%	10.2%	9.8%	10.0%	10.6%	10.9%	11.5%	11.6%	11.0%	12.0%	***12.5%***	***12.5%***	Return on Com Equity E	***13.0%***
							6.5%	4.0%	3.3%	3.5%	3.8%	3.6%	2.8%	3.6%	3.0%	3.5%	***4.5%***	***4.5%***	Retained to Com Eq	***5.5%***
							47%	61%	67%	64%	64%	67%	76%	69%	73%	81%	***75%***	***75%***	All Div'ds to Net Prof	***57%***

CAPITAL STRUCTURE as of 9/30/24
Total Debt $5053.2 mill. **Due in 5 Yrs** $1731.5 mill.
LT Debt $5020.8 mill. **LT Interest** $158.7 mill.
(LT interest earned: 4.3x)

Leases, Uncapitalized Annual rentals $5.7 mill.

Pension Assets-12/22 $486.0 mill.
Oblig $502.9 mill.

Pfd Stock None

Common Stock 200,947,879 shs.

MARKET CAP: $8.0 billion (Mid Cap)

ELECTRIC OPERATING STATISTICS

	2020	2021	2022
% Change Retail Sales (KWH)	-4.9	+2.6	+8.3
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	4.40	7.68	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	6437	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+1.1	+1.4	NA
Fixed Charge Cov. (%)	326	336	335

ANNUAL RATES of change (per sh)

	Past 10 Yrs.	Past 5 Yrs.	Est'd '21-'23 to '27-'29
Revenues	-3.0%	5.0%	*5.5%*
"Cash Flow"	2.5%	5.0%	*7.0%*
Earnings	3.0%	4.5%	*6.5%*
Dividends	7.5%	6.5%	*3.0%*
Book Value	4.0%	1.5%	*5.5%*

QUARTERLY REVENUES ($ mill.)

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	1630.0	577.4	864.4	581.3	3653.7
2022	589.3	803.7	1270.0	711.9	3375.7
2023	557.2	605.0	945.4	566.7	2674.3
2024	596.8	662.6	965.4	***675.2***	***2900***
2025	***620***	***780***	***950***	***650***	***3000***

EARNINGS PER SHARE A

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	.26	.56	1.26	.28	2.36
2022	.33	.36	1.31	.25	2.25
2023	.19	.44	1.20	.24	2.07
2024	.09	.51	1.09	***.46***	***2.15***
2025	***.40***	***.35***	***1.30***	***.25***	***2.30***

QUARTERLY DIVIDENDS PAID B ■

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2020	.3875	.3875	.3875	.4025	1.57
2021	.4025	.4025	.4025	.41	1.62
2022	.41	.41	.41	.4141	1.64
2023	.4141	.4141	.4141	.4182	1.66
2024	.4182	.4182	.4182	.4213	

BUSINESS: OGE Energy Corp. is a holding company for Oklahoma Gas and Electric Company (OG&E), which supplies electricity to 879,000 customers in Oklahoma (84% of electric revenues) and western Arkansas (8%); wholesale is (8%). Owns 3% of Energy Transfer's limited partnership units. Electric revenue breakdown: residential, 44%; commercial, 25%; industrial, 11%; oilfield, 10%; other, 10%. Generating sources: gas, 25%; coal, 21%; wind, 6%; purchased, 48%. Fuel costs: 58% of revenues. '23 reported depreciation rate (utility): 2.6%. Has 2,200 employees. Chairman, President and Chief Executive Officer: Sean Trauschke. Incorporated: Oklahoma. Address: 321 North Harvey, P.O. Box 321, Oklahoma City, OK 73101-0321. Tel.: 405-553-3000. Internet: www.oge.com.

OGE Energy's utility subsidiary is progressing on the regulatory front. Remember that in Oklahoma, a $126.6 million rate increase took effect in July, subject to a final order to approve the hike. The Oklahoma Corporation Commission recently delayed the vote due to differences of opinions between commission chairs. The utility initially proposed a $322 million (13.85%) hike or a $19.02 average monthly rise per residential customer. The increase will likely help OGE recover essential capital investments to strengthen and improve the reliability of the electric grid. An order is expected by the end of this year or the beginning of 2025.

Our 2024 profit estimate is staying put at $2.15 a share. Management looks for earnings to come in at the high end of its range of $2.06-$2.18 due to strong load growth and warmer than normal weather. This assumes approval of the Oklahoma rate review, among other things. We look for sharper growth next year compared to 2024 levels. Indeed, our 2025 bottom-line estimate represents 7% growth from our 2024 projections. OGE looks to be increasingly well positioned over the next few years, and should take advantage of increased power demand and the clean energy transition, as a pure play electric utility.

The board of directors has raised the dividend, effective with the October payment. The increase was modest, at $0.003 a share quarterly (1% higher). This issue offers a very attractive dividend, and the yield of 4.3% stands comfortably above the utility average, which is one of the best dividend-paying industries in the market.

This issue is best suited for income-oriented investors. The aforementioned recently raised dividend distribution remains the most notable feature at this juncture. But, intermediate- and long-term risk-adjusted capital appreciation potential is unattractive. Indeed, the current quotation is well within both our 18-month and 3- to 5-year Target Price Ranges. Too, the Timeliness rank has been lowered one notch to 4 (Below Average), which means OGE is slated to trail the broader market averages in the year ahead.

Zachary J. Hodgkinson *December 6, 2024*

(A) Diluted EPS. Excl. nonrecurring gains (losses): '15, (33¢); '17, $1.18; '19, (8¢); '20, ($2.95); '21, $1.32; '22, $1.06; gain on discont. ops.: '19 & '21 EPS don't sum due to rounding. Next earnings report due mid Feb. **(B)** Div'ds historically paid in late Jan., Apr., July, & Oct. ■ Div'd reinvestment plan avail. **(C)** Incl. deferred charges. In '22: $6.15/sh. **(D)** In mill., adj. for split. **(E)** Rate base: Net original cost. Rate allowed on com. eq. in OK in '19: 9.5%; in AR in '18: 9.5%; earned on avg. com. eq., '21: 12.7%. Regulatory Climate: Average.

Company's Financial Strength	B++
Stock's Price Stability	80
Price Growth Persistence	30
Earnings Predictability	95

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PINNACLE WEST NYSE-PNW

RECENT PRICE **83.09** | P/E RATIO **17.0** (Trailing: 15.7 Median: 17.0) | RELATIVE P/E RATIO **0.94** | DIV'D YLD **4.3%** | **VALUE LINE**

TIMELINESS 3 Raised 12/13/24
SAFETY 2 Raised 10/18/24
TECHNICAL 1 Raised 1/3/25
BETA .95 (1.00 = Market)

18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$62-$99	$81 (-10%)

2027-29 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	125	(+50%)	*14%*
Low	90	(+10%)	*6%*

Institutional Decisions

	1Q2024	2Q2024	3Q2024
to Buy	234	245	274
to Sell	268	225	226
Hld's(000)	110427	114098	123296

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	© VALUE LINE PUB. LLC	27-29
High:	61.9	71.1	73.3	82.8	92.5	92.6	99.8	105.5	88.5	80.6	86.0	95.4								
Low:	51.5	51.2	56.0	62.5	75.8	73.4	81.6	60.1	62.8	59.0	68.6	65.2								
	33.37	32.50	30.01	29.67	30.09	31.35	31.58	31.50	31.42	31.90	32.93	30.87	31.81	33.66	38.21	41.40	***44.50***	***43.20***	Revenues per sh	***50.00***
	8.13	8.08	6.85	7.52	7.92	8.15	8.09	9.09	9.39	9.92	10.37	10.69	10.97	11.84	11.50	11.95	***13.10***	***12.95***	"Cash Flow" per sh	***15.35***
	2.12	2.26	3.08	2.99	3.50	3.66	3.58	3.92	3.95	4.43	4.54	4.77	4.87	5.47	4.26	4.41	***5.10***	***4.80***	Earnings per sh [A]	***6.00***
	2.10	2.10	2.10	2.10	2.67	2.23	2.33	2.44	2.56	2.70	2.87	3.04	3.23	3.36	3.43	3.49	3.55	***3.61***	Div'd Decl'd per sh [B] ■	***3.80***
	9.46	7.64	7.03	8.26	8.24	9.36	8.38	9.84	11.64	12.80	10.73	10.76	11.93	13.04	15.09	16.28	***17.00***	***17.00***	Cap'l Spending per sh	***17.20***
	34.16	32.69	33.86	34.98	36.20	38.07	39.50	41.30	43.15	44.80	46.59	48.30	49.96	52.26	53.45	54.47	***61.30***	***61.20***	Book Value per sh [C]	***69.95***
	100.89	101.43	108.77	109.25	109.74	110.18	110.57	110.98	111.34	111.75	112.10	112.44	112.76	113.01	113.17	113.42	***114.00***	***118.00***	Common Shs Outst'g [D]	***125.00***
	16.1	13.7	12.6	14.6	14.3	15.3	15.9	16.0	18.7	19.3	17.8	19.4	16.7	14.1	17.1	17.4	***15.7***		Avg Ann'l P/E Ratio	***18.0***
	.97	.91	.80	.92	.91	.86	.84	.81	.98	.97	.96	1.03	.86	.76	.99	.97	***.87***		Relative P/E Ratio	***1.00***
	6.2%	6.8%	5.4%	4.8%	5.3%	4.0%	4.1%	3.9%	3.5%	3.2%	3.5%	3.3%	4.0%	4.3%	4.7%	4.5%	4.4%		Avg Ann'l Div'd Yield	***3.5%***
							3491.6	3495.4	3498.7	3565.3	3691.2	3471.2	3587.0	3803.8	4324.4	4696.0	***5075***	***5100***	Revenues ($mill)	***6250***
							397.6	437.3	442.0	497.8	511.0	538.3	550.6	618.7	483.6	501.6	***580***	***560***	Net Profit ($mill)	***750***
							34.2%	34.3%	33.9%	32.5%	20.2%	- -	12.1%	14.8%	13.0%	12.9%	***14.0%***	***14.0%***	Income Tax Rate	***14.0%***
							11.6%	11.8%	14.1%	13.9%	15.2%	9.3%	9.5%	10.1%	15.2%	19.3%	***19.5%***	***20.5%***	AFUDC % to Net Profit	***22.0%***
							41.0%	43.0%	45.6%	48.9%	47.0%	47.1%	52.8%	53.9%	56.1%	55.0%	***52.5%***	***54.0%***	Long-Term Debt Ratio	***52.0%***
							59.0%	57.0%	54.4%	51.1%	53.0%	52.9%	47.2%	46.1%	43.9%	45.0%	***47.5%***	***46.0%***	Common Equity Ratio	***48.0%***
							7398.7	8046.3	8825.4	9796.4	9861.1	10263	11948	12820	13790	13718	***14650***	***15650***	Total Capital ($mill)	***18300***
							11194	11809	12714	13445	14030	14523	15159	15987	16854	17980	***19025***	***20050***	Net Plant ($mill)	***23050***
							6.4%	6.4%	6.0%	6.1%	6.2%	6.3%	5.5%	5.8%	4.5%	5.0%	***5.0%***	***5.0%***	Return on Total Cap'l	***5.5%***
							9.1%	9.5%	9.2%	9.9%	9.8%	9.9%	9.8%	10.5%	8.0%	8.1%	***8.5%***	***7.5%***	Return on Shr. Equity	***8.5%***
							9.1%	9.5%	9.2%	9.9%	9.8%	9.9%	9.8%	10.5%	8.0%	8.1%	***8.5%***	***7.5%***	Return on Com Equity [E]	***8.5%***
							3.5%	3.9%	3.5%	4.2%	3.9%	3.8%	3.5%	4.2%	1.7%	1.9%	***2.5%***	***2.0%***	Retained to Com Eq	***3.0%***
							62%	59%	62%	58%	60%	61%	64%	60%	78%	77%	***69%***	***75%***	All Div'ds to Net Prof	***63%***

CAPITAL STRUCTURE as of 9/30/24
Total Debt $9679.7 mill. **Due in 5 Yrs** $2225.0 mill.
LT Debt $8056.2 mill. **LT Interest** $355.0 mill.
(Total Interest Coverage: 2.8x)

Leases, Uncapitalized Annual rentals $19.2 mill.

Pension Assets-12/23 $2835.5 mill.
Oblig. $2908.1 mill.

Pfd Stock None

Common Stock 113,699,820 shs.
as of 10/30/24
MARKET CAP: $9.4 billion (Mid Cap)

ELECTRIC OPERATING STATISTICS

	2021	2022	2023
% Change Retail Sales (KWH)	-.1	+4.4	+2.8
Avg. Indust. Use (MWH)	808	849	874
Avg. Indust. Revs. per KWH (¢)	8.11	9.20	10.38
Capacity at Peak (Mw)	8726	8612	9629
Peak Load, Summer (Mw)	7580	7587	8159
Annual Load Factor (%)	45.1	48.1	45.7
% Change Customers (yr-end)	+2.2	+2.1	+1.8
Fixed Charge Cov. (%)	317	226	220

ANNUAL RATES of change (per sh)

	Past 10 Yrs.	Past 5 Yrs.	Est'd '21-'23 to '27-'29
Revenues	2.0%	3.5%	*5.0%*
"Cash Flow"	4.0%	3.5%	*4.5%*
Earnings	3.5%	2.0%	*4.0%*
Dividends	4.0%	5.0%	*1.5%*
Book Value	4.0%	3.5%	*4.5%*

QUARTERLY REVENUES ($ mill.)

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	696.5	1000.2	1308.2	798.9	3803.8
2022	783.5	1061.7	1469.9	1009.3	4324.4
2023	945.0	1121.7	1637.8	991.5	4696.0
2024	951.7	1309.0	1768.8	***1045.5***	***5075***
2025	***1000***	***1260***	***1750***	***1090***	***5100***

EARNINGS PER SHARE [A]

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	.32	1.91	3.00	.24	5.47
2022	.15	1.45	2.88	d.21	4.26
2023	d.03	.94	3.50	Nil	4.41
2024	.15	1.76	3.37	***d.18***	***5.10***
2025	***.20***	***1.50***	***3.25***	***d.15***	***4.80***

QUARTERLY DIVIDENDS PAID [B] ■

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	.83	.83	.83	.85	3.34
2022	.85	.85	.85	.865	3.42
2023	.865	.865	.865	.88	3.48
2024	.88	.88	.88	.895	3.54
2025					

BUSINESS: Pinnacle West Capital Corporation is a holding company for Arizona Public Service Company (APS), which supplies electricity to 1.4 million customers in most of Arizona, except about half of the Phoenix metro area, the Tucson metro area, and Mohave County in northwestern Arizona. Discontinued SunCor real estate subsidiary in '10. Electric revenue breakdown: residential, 49%; commercial/industrial, 44%; other, 7%. Generating sources: gas, 25%; nuclear, 25%; coal, 18%; renewables, 2%; purchased, 30%. Fuel costs: 38% of revenues. '23 reported deprec. rate: 2.98%. Has 6,133 employees. Chairman, President & CEO: Jeffrey B. Guldner. Inc.: AZ. Address: 400 North Fifth St., P.O. Box 53999, Phoenix, AZ 85072-3999. Tel.: 602-250-1000. Internet: www.pinnaclewest.com.

Pinnacle West Capital will likely report a very strong earnings gain for 2024. Constructive progress on the regulatory front last March helped. A revamped Arizona Corporate Commission raised the utility's authorized return on equity (ROE) to 9.55%, with upside to 9.85% if certain conditions are met, from a miserly 8.7% previously. The restoration of a more reasonable regulated ROE boosted Pinnacle West's earnings power by about $1.00 per share. In addition, the company benefited from a record-setting heat wave in its Arizona service area, as customers used more electricity to cool their homes and businesses. There was a stretch of 113 consecutive days when temperatures rose above 100 degrees in the Phoenix area. There were also 70 days when temperatures rose above 110 degrees, which was up from the previous record of 55 days above 110, set in 2023.

Management expects the company's overheated bottom line to cool off some this year. It has provided a preliminary 2025 weather-normalized earnings projection of $4.40 to $4.60 per share. We suspect the company will be proven to be too conservative in its forecast. Sweltering heat in 2023 followed by an even more oppressive stretch in 2024 doesn't seem like a trend that will pivot back to management's idea of average temperatures, which are based on several decades of data. In addition, Pinnacle West's service area benefits from strong migration, as Arizona's 2.5% flat income tax rate helps draw in out-of-state retirees. A business friendly government also keeps the regional economy headed in the right direction. Customer growth was likely up 2% last year and will probably be up by a similar amount going forward.

These shares are neutrally ranked for year-ahead relative performance. Longer term, we like this electric utility a lot, as it's the beneficiary of a premium service area in terms of rising energy demand from population growth and a thriving economy. Even so, utility investors need to be disciplined buyers and wait for a bit more of a drawdown before committing here. A 5%-7% dip would translate to a worthwhile risk-adjusted annual total return expectation.

Anthony J. Glennon *January 17, 2025*

(A) Diluted EPS. Excl. nonrec. gain/(loss): '09, ($1.45); '17, 8¢; gains/(losses) from discont. ops.: '08, 28¢; '09, (13¢); '10, 18¢; '11, 10¢; '12, (5¢). Qtly. EPS may not sum to full year due to rounding. Next egs. report due late Feb. **(B)** Div'ds historically paid in early Mar., June, Sept., & Dec. There were 5 declarations in '12. ■ Div'd reinvestment plan avail. **(C)** Incl. deferred charges/other intangibles. In '23: $27.22/sh. **(D)** In mill. **(E)** Rate base: Fair value. Rate allowed on common equity in '24: 9.55%-9.85%. Regulatory Climate: Average.

Company's Financial Strength	A
Stock's Price Stability	85
Price Growth Persistence	30
Earnings Predictability	85

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PORTLAND GENERAL NYSE-POR

RECENT PRICE **42.33** | P/E RATIO **13.8** (Trailing: 12.2 Median: 18.0) | RELATIVE P/E RATIO **0.76** | DIV'D YLD **4.9%** | **VALUE LINE**

TIMELINESS 3 Raised 11/15/24
SAFETY 2 Raised 7/19/24
TECHNICAL 1 Raised 1/10/25
BETA .95 (1.00 = Market)

18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$39-$60	$50 (5%)

2027-29 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	75	(+75%)	*19%*
Low	55	(+30%)	*11%*

Institutional Decisions

	1Q2024	2Q2024	3Q2024
to Buy	186	240	241
to Sell	188	144	166
Hld's(000)	102071	106708	118198

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
High:	33.3	40.3	41.0	45.2	50.1	50.4	58.4	63.1	53.1	57.0	51.6	49.8						
Low:	27.4	29.0	33.0	35.3	42.4	39.0	44.0	32.0	40.8	41.6	38.0	39.1						

LEGENDS
25.6 x Dividends p sh
Relative Price Strength
Options: Yes
Shaded area indicates recession

Target Price Range 2027 | 2028 | 2029
128 / 96 / 80 / 64 / 48 / 40 / 32 / 24 / 16 / 12

Percent shares traded: 21 / 14 / 7

% TOT. RETURN 12/24

	THIS STOCK	VL ARITH.* INDEX
1 yr.	6.8	13.6
3 yr.	-5.5	14.7
5 yr.	-3.4	70.9

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	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	
	27.89	23.99	23.67	24.06	23.89	23.18	24.29	21.38	21.62	22.54	22.30	23.75	23.96	26.80	29.65	28.90	*31.40*	*32.75*	Revenues per sh
	4.71	4.07	4.82	4.96	5.15	4.93	6.08	5.37	5.78	6.16	6.65	6.97	7.83	7.25	7.41	6.83	*7.75*	*8.10*	"Cash Flow" per sh
	1.39	1.31	1.66	1.95	1.87	1.77	2.18	2.04	2.16	2.29	2.37	2.39	2.75	2.72	2.74	2.38	*3.10*	*3.25*	Earnings per sh [A]
	.97	1.01	1.04	1.06	1.08	1.10	1.12	1.18	1.26	1.34	1.43	1.52	1.59	1.70	1.79	1.88	1.98	*2.08*	Div'd Decl'd per sh [B] ■ †
	6.12	9.25	5.97	3.98	4.01	8.40	12.87	6.73	6.57	5.77	6.67	6.78	8.76	7.11	8.58	13.42	*12.35*	*11.00*	Cap'l Spending per sh
	21.64	20.50	21.14	22.07	22.87	23.30	24.43	25.43	26.35	27.11	28.07	28.99	29.18	30.28	31.13	32.81	*34.35*	*35.90*	Book Value per sh [C]
	62.58	75.21	75.32	75.36	75.56	78.09	78.23	88.79	88.95	89.11	89.27	89.39	89.54	89.41	89.28	101.16	*106.00*	*110.00*	Common Shs Outst'g [D]
	16.3	14.4	12.0	12.4	14.0	16.9	15.3	17.7	19.1	20.0	18.4	22.3	16.6	17.7	18.2	19.3	*14.3*		Avg Ann'l P/E Ratio
	.98	.96	.76	.78	.89	.95	.81	.89	1.00	1.01	.99	1.19	.85	.96	1.05	1.08	*.79*		Relative P/E Ratio
	4.3%	5.4%	5.2%	4.4%	4.1%	3.7%	3.3%	3.3%	3.1%	2.9%	3.3%	2.8%	3.5%	3.5%	3.6%	4.1%	4.4%		Avg Ann'l Div'd Yield
							1900.0	1898.0	1923.0	2009.0	1991.0	2123.0	2145.0	2396.0	2647.0	2923.0	*3330*	*3600*	Revenues ($mill)
							175.0	172.0	193.0	204.0	212.0	214.0	247.0	244.0	245.0	233.0	*320*	*350*	Net Profit ($mill)
							26.0%	20.7%	20.6%	25.3%	7.4%	11.2%	12.4%	8.6%	15.2%	16.8%	*17.5%*	*17.5%*	Income Tax Rate
							33.7%	19.8%	16.6%	8.8%	8.0%	7.0%	9.7%	10.2%	8.6%	13.7%	*11.0%*	*11.0%*	AFUDC % to Net Profit
							52.7%	47.8%	48.4%	50.1%	46.5%	51.3%	53.6%	56.8%	57.0%	55.8%	*56.0%*	*55.5%*	Long-Term Debt Ratio
							47.3%	52.2%	51.6%	49.9%	53.5%	48.7%	46.4%	43.2%	43.0%	44.2%	*44.0%*	*44.5%*	Common Equity Ratio
							4037.0	4329.0	4544.0	4842.0	4684.0	5323.0	5628.0	6265.0	6459.0	7513.0	*8300*	*8900*	Total Capital ($mill)
							5679.0	6012.0	6434.0	6741.0	6887.0	7161.0	7539.0	8005.0	8465.0	9546.0	*10350*	*11000*	Net Plant ($mill)
							5.8%	5.4%	5.6%	5.5%	5.8%	5.1%	5.6%	4.9%	4.9%	4.2%	*5.0%*	*5.0%*	Return on Total Cap'l
							9.2%	7.6%	8.2%	8.4%	8.5%	8.3%	9.5%	9.0%	8.8%	7.0%	*9.0%*	*9.0%*	Return on Shr. Equity
							9.2%	7.6%	8.2%	8.4%	8.5%	8.3%	9.5%	9.0%	8.8%	7.0%	*9.0%*	*9.0%*	Return on Com Equity [E]
							4.6%	3.3%	3.5%	3.6%	3.5%	3.1%	4.1%	3.5%	3.1%	1.6%	*3.0%*	*3.0%*	Retained to Com Eq
							50%	56%	57%	58%	59%	63%	57%	61%	64%	77%	*64%*	*64%*	All Div'ds to Net Prof

CAPITAL STRUCTURE as of 9/30/24
Total Debt $4739 mill. **Due in 5 Yrs** $570 mill.
LT Debt $4633 mill. **LT Interest** $205 mill.
Incl. $279 mill. finance leases.
(Total Interest Coverage: 2.8x)
Leases, Uncapitalized Annual rentals $3 mill.
Pension Assets-12/23 $530 mill.
Oblig. $690 mill.
Pfd Stock None

Common Stock 105,455,590 shs.
as of 10/18/24

MARKET CAP: $4.5 billion (Mid Cap)

ELECTRIC OPERATING STATISTICS

	2021	2022	2023
% Change Retail Sales (KWH)	+5.1	+3.4	+.9
Avg. Indust. Use (MWH)	20002	22097	23052
Avg. Indust. Revs. per KWH (¢)	5.22	5.23	5.85
Capacity at Peak (MW)	NA	NA	NA
Peak Load, Summer (MW)	4453	4255	4498
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+.6	+1.1	+.7
Fixed Charge Cov. (%)	261	254	217

ANNUAL RATES of change (per sh)

	Past 10 Yrs.	Past 5 Yrs.	Est'd '21-'23 to '27-'29
Revenues	2.0%	5.0%	*3.5%*
"Cash Flow"	3.5%	3.0%	*5.0%*
Earnings	3.5%	3.0%	*5.5%*
Dividends	5.0%	6.0%	*5.5%*
Book Value	3.5%	3.0%	*4.0%*

QUARTERLY REVENUES ($ mill.)

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	609	537	642	608	2396
2022	626	591	743	687	2647
2023	748	648	802	725	2923
2024	929	758	929	*714*	*3330*
2025	*975*	*800*	*1000*	*825*	*3600*

EARNINGS PER SHARE [A]

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	1.07	.36	.56	.73	2.72
2022	.67	.72	.65	.70	2.74
2023	.80	.44	.46	.67	2.38
2024	1.21	.69	.90	*.30*	*3.10*
2025	*1.17*	*.70*	*.93*	*.45*	*3.25*

QUARTERLY DIVIDENDS PAID [B] ■ †

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	.4075	.4075	.43	.43	1.68
2022	.43	.43	.4525	.4525	1.77
2023	.4525	.4525	.475	.475	1.86
2024	.475	.475	.50	.50	1.95
2025	.50				

BUSINESS: Portland General Electric Company provides electricity to 934,000 customers in 51 cities in a 4,000-square-mile area of Oregon, including Portland and Salem (population: 1.9 million). The company is in the process of decommissioning the Trojan nuclear plant, which was closed in 1993. Electric revenue breakdown: residential, 52%; commercial, 33%; industrial, 15%; other, less than 1%. Generating sources: gas, 40%; wind, 7%; coal, 8%; hydro, 4%; purchased, 41%. Fuel costs: 40% of revenues. '23 reported depreciation rate: 3.4%. Has 2,842 full-time employees. Chair: James P. Torgerson. President and CEO: Maria M. Pope. Incorporated: Oregon. Address: 121 S.W. Salmon Street, Portland, OR 97204. Tel.: 503-464-8000. Internet: www.portlandgeneral.com.

Portland General Electric should report a strong bottom-line increase for 2024. Admittedly, 2023 comparisons were easy to improve upon, as demand suffered from mild weather. At the same time, purchased-power costs were exceptionally high in 2023. The weather situation improved last year, and volumes rose due to strong demand growth from the semiconductor industry and data centers. It was also a plus that Portland General has become less reliant on volatile at-the-market purchased power. The utility brought its Clearwater Wind development project on line early in 2024. Portland General will continue to bring on new renewable capacity additions under the formula of half company owned and half long-term stable purchased power agreements from a strategic partner.

Higher electric rates are likely to lift earnings further in 2025. In December, the utility received its general rate case decision from Oregon regulators. Effective from January 1st of this year, residential rates are set to rise by 5.5%. Commercial and industrial rates will be up as much as 7.7%. The company was seeking an 8.6% across-the-board hike in rates for recoupment of investments made, plus timely recovery mechanisms via customer billing pass-throughs. The new rates are based on an authorized return on equity of 9.35%, which suffered a 15 basis point trim from the previous 9.5% level.

Longer-term prospects are favorable. Portland General ought to benefit from 2%-3% annual load growth, supported by a healthy high-tech industrial segment in its service area. Profitability will likely be on the rise, as the utility continues to reduce its reliance on open-market power purchases, which are vulnerable to price spikes during periods of high demand or constrained supply. Portland General has the green light from regulators to add more nonemitting annual power generation, plus significant battery storage capacity. Over the stretch to 2027-2029, 5%-6% annual earnings gains looks feasible.

Utility investors focused on the longer term should find this equity of interest. POR's dividend yield is 120 basis points above the peer-group average. And, total return prospects look worthwhile.

Anthony J. Glennon *January 17, 2025*

(A) Diluted earnings. Excl. nonrecurring gains/(losses): '13, (42¢); '17, (19¢); '20, ($1.03); '22, (14¢); '23, (5¢); Q1-Q3 '24, (13¢). Quarterly EPS many not sum to full year due to rounding. Next earnings report due mid-Feb. **(B)** Dividends paid mid-Jan., Apr., July, and Oct. ■ Dividend reinvestment plan available. † Shareholder investment plan available. **(C)** Incl. deferred charges. In '23: $492 mill., $4.86/sh. **(D)** In mill. **(E)** Rate base: Net original cost. Rate allowed on common equity in '25: 9.34%. Regulatory Climate: Average.

Company's Financial Strength	A
Stock's Price Stability	90
Price Growth Persistence	30
Earnings Predictability	90

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SOUTHERN COMPANY NYSE-SO

RECENT PRICE **86.50** | P/E RATIO **20.6** (Trailing: 20.6 Median: 17.0) | RELATIVE P/E RATIO **1.13** | DIV'D YLD **3.4%** | **VALUE LINE**

TIMELINESS 4 Lowered 11/29/24
SAFETY 2 Lowered 2/21/14
TECHNICAL 2 Raised 2/7/25
BETA .95 (1.00 = Market)

18-Month Target Price Range

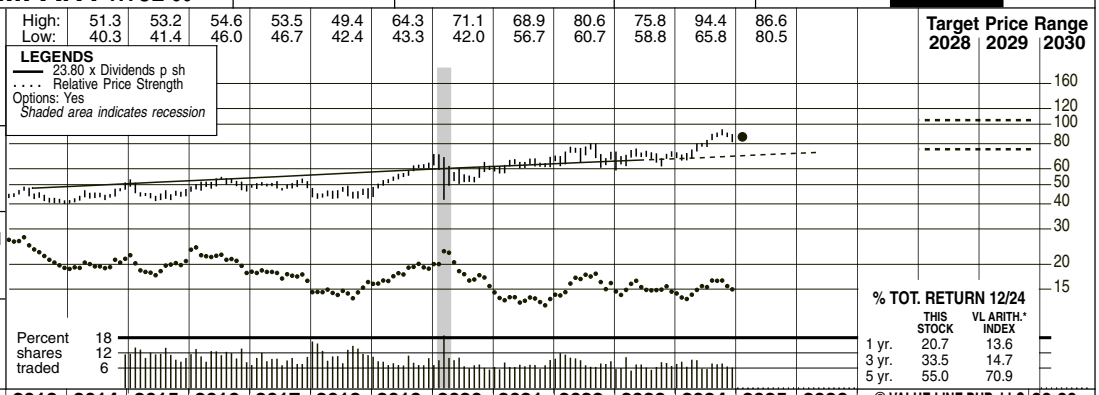
Low-High	Midpoint (% to Mid)
$64-$98	$81 (-5%)

2028-30 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	105	(+20%)	*8%*
Low	75	(-15%)	*Nil*

Institutional Decisions

	1Q2024	2Q2024	3Q2024
to Buy	822	895	980
to Sell	786	732	765
Hld's(000)	707349	735543	829101



2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	© VALUE LINE PUB. LLC	28-30
19.21	20.70	20.41	19.06	19.26	20.34	19.18	20.09	22.86	22.73	20.34	19.29	21.80	26.89	23.15	*24.15*	*24.85*	*25.80*	Revenues per sh	*28.30*
4.43	4.51	4.91	5.18	5.27	5.28	5.47	5.69	6.64	6.41	6.33	6.98	7.20	7.34	7.79	*8.25*	*8.50*	*8.80*	"Cash Flow" per sh	*9.70*
2.32	2.36	2.55	2.67	2.70	2.77	2.84	2.83	3.21	3.00	3.17	3.25	3.42	3.61	3.64	*4.05*	*4.30*	*4.60*	Earnings per sh [A]	*5.50*
1.73	1.80	1.87	1.94	2.01	2.08	2.15	2.22	2.30	2.38	2.46	2.54	2.62	2.70	2.78	2.86	*2.96*	*3.05*	Div'd Decl'd per sh [B] ■	*3.10*
5.70	4.85	5.23	5.54	6.16	6.58	6.22	7.38	7.37	7.74	7.17	7.04	6.83	7.87	8.88	*8.85*	*8.75*	*8.70*	Cap'l Spending per sh	*8.50*
18.15	19.21	20.32	21.09	21.43	21.98	22.59	25.00	23.98	23.92	26.11	26.48	26.30	27.93	28.82	*29.90*	*31.75*	*31.90*	Book Value per sh [C]	*32.25*
819.65	843.34	865.13	867.77	887.09	907.78	911.72	990.39	1007.6	1033.8	1053.3	1056.5	1060.0	1089.0	1091.0	*1095.0*	*1095.0*	*1095.0*	Common Shs Outst'g [D]	*1095.0*
13.5	14.9	15.8	17.0	16.2	16.0	15.8	17.8	15.5	15.1	17.6	17.9	18.4	19.6	19.1	*19.6*	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	*16.5*
.90	.95	.99	1.08	.91	.84	.80	.93	.78	.82	.94	.92	1.00	1.14	1.06	*1.09*			Relative P/E Ratio	*.90*
5.5%	5.1%	4.6%	4.3%	4.6%	4.7%	4.8%	4.4%	4.6%	5.3%	4.4%	4.4%	4.2%	4.1%	4.1%	3.4%			Avg Ann'l Div'd Yield	*3.6%*
17489	19896	23031	23495	21419	20375	23113	29279	25253	*26450*	*27200*	*28250*	Revenues ($mill)	*31000*
2647.0	2757.0	3269.0	3096.0	3354.0	3481.0	3670.0	3931.3	3976.0	*4435*	*4710*	*5035*	Net Profit ($mill)	*6025*
33.4%	28.5%	25.2%	21.3%	15.9%	14.3%	16.3%	18.9%	11.4%	*15.0%*	*15.0%*	*15.0%*	Income Tax Rate	*15.0%*
13.2%	11.9%	7.6%	6.8%	6.0%	6.6%	7.7%	8.0%	7.9%	*8.0%*	*8.0%*	*8.0%*	AFUDC % to Net Profit	*6.0%*
52.8%	61.5%	64.5%	62.0%	60.1%	61.5%	64.0%	63.0%	65.6%	*64.0%*	*64.0%*	*64.0%*	Long-Term Debt Ratio	*63.0%*
44.0%	35.7%	35.0%	37.6%	39.5%	38.1%	35.6%	36.5%	37.6%	*36.0%*	*36.0%*	*36.0%*	Common Equity Ratio	*37.0%*
46788	69359	68953	65750	69594	73336	78285	80558	83654	*85000*	*87500*	*90000*	Total Capital ($mill)	*93500*
61114	78446	79872	80797	83080	87634	91108	94570	99844	*100000*	*100500*	*100800*	Net Plant ($mill)	*110000*
6.6%	4.9%	5.9%	5.9%	6.0%	5.9%	5.8%	5.5%	4.6%	*5.5%*	*5.5%*	*5.5%*	Return on Total Cap'l	*6.5%*
12.0%	10.3%	13.3%	12.4%	12.1%	12.3%	13.0%	12.5%	12.6%	*13.0%*	*13.0%*	*13.0%*	Return on Shr. Equity	*14.5%*
12.6%	11.0%	13.4%	12.5%	12.1%	12.4%	13.1%	12.5%	12.6%	*13.0%*	*13.0%*	*13.0%*	Return on Com Equity [E]	*14.5%*
3.1%	2.5%	3.9%	2.6%	2.8%	2.8%	3.1%	3.0%	3.2%	*3.5%*	*3.5%*	*3.5%*	Retained to Com Eq	*5.0%*
76%	78%	72%	79%	77%	78%	76%	78%	77%	*77%*	*77%*	*77%*	All Div'ds to Net Prof	*67%*

CAPITAL STRUCTURE as of 9/30/24
Total Debt $62896 mill. **Due in 5 Yrs** $15427 mill.
LT Debt $61254 mill. **LT Interest** $1754 mill.
Incl. $215 mill. finance leases.
(LT interest earned: 3.3x)
Leases, Uncapitalized Annual rentals $307 mill.
Pension Assets-12/23 $14218 mill.
Oblig $16382 mill.
Pfd Stock $242 mill. **Pfd Div'd** $15 mill.
Incl. 10 mill. shs. 5.83% cum. pfd. ($25 stated value); 475,115 shs. 4.2%-5.44% cum. pfd. ($100 par).
Common Stock 1,095,684,180 shs.
MARKET CAP: $94.8 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2021	2022	2023
% Change Retail Sales (KWH)	-5.3	+2.0	NA
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Yearend (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+1.3	+1.5	NA
Fixed Charge Cov. (%)	270	275	NA

ANNUAL RATES of change (per sh)

	Past 10 Yrs.	Past 5 Yrs.	Est'd '21-'23 to '28-'30
Revenues	- -	.5%	*6.0%*
"Cash Flow"	4.0%	4.5%	*5.0%*
Earnings	3.0%	3.0%	*6.5%*
Dividends	3.5%	3.5%	*3.5%*
Book Value	3.0%	2.5%	*3.5%*

QUARTERLY REVENUES (mill.)

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2022	6648	7206	8378	7047	29279
2023	6480	5748	6980	6045	25253
2024	6646	6463	7274	*6067*	*26450*
2025	*7000*	*6500*	*7300*	*6400*	*27200*
2026	*7250*	*6700*	*7500*	*6800*	*28250*

EARNINGS PER SHARE [A]

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2022	.97	1.07	1.31	.26	3.61
2023	.79	.79	1.42	.64	3.64
2024	1.03	1.10	1.43	*.49*	*4.05*
2025	*1.10*	*1.10*	*1.50*	*.60*	*4.30*
2026	*1.15*	*1.20*	*1.55*	*.70*	*4.60*

QUARTERLY DIVIDENDS PAID [B] ■

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	.64	.66	.66	.66	2.62
2022	.66	.68	.68	.68	2.70
2023	.68	.70	.70	.70	2.78
2024	.70	.72	.72	.72	2.86
2025					

BUSINESS: The Southern Company, through its subsidiaries, supplies electricity to 4.4 mill. customers in GA, AL, and MS. Also has a competitive generation business. Acq'd AGL Resources (renamed Southern Company Gas, 4.4 mill. customers in GA, NJ, IL, VA, & TN) 7/16. Sold Gulf Power 1/19. Electric revenue breakdown: residential, 43%; commercial, 35%; industrial, 21%; other, 1%. Generating sources: gas, 51%; coal, 19%; nuclear, 10%; other, 11%; purchased, 9%. Fuel costs: 26% of revenues. '23 reported deprec. rates (utility): 2.7%-3.4%. Has 27,300 employees. President and CEO: Chris Womack. Incorporated.: Delaware. Address: 30 Ivan Allen Jr. Blvd., N.W., Atlanta, Georgia 30308. Telephone: 404-506-0747. Internet: www.southerncompany.com.

We look for Southern Company's earnings to advance moderately in 2025. Our profit estimate this year remains unchanged at $4.30 per share, implying 6% growth, which is in line with the utility's long-term 5%-7% target. The recent completion of the Vogtle Nuclear Construction Project should start to benefit results in 2025 and beyond. The Vogtle plant stands to deliver 2,200 megawatts of reliable, carbon free energy for decades, and is the largest generator of clean energy in the U.S. In turn, Southern is increasingly well positioned to take advantage of the clean energy transition and elevated power demand due to technological advancements.

We have introduced our top- and bottom-line estimates for 2026. We think the company will post similar growth in 2026, within management's long-term targets. The demand for nuclear power expansion and electricity should remain elevated for the foreseeable future. And, Southern continues to expect that the U.S. will need to install more than 10 gigawatts of nuclear power to meet increased electricity demand in the coming years. Accordingly, we look for earnings of $4.60 per share and revenues of $28.25 billion.

These shares have fallen a bit in value since our early November report. The stock is down more than 5% over that interim, partly due to weak projected year over year earnings comparisons as well as increased energy transition costs. Still, Southern shares are up more than 25% over the past year, along with the sharp rise in demand for nuclear power expansion and electricity.

This issue is best suited for conservative, income-oriented investors. Indeed, the utility pays a solid dividend, which remains its most notable feature, and is ranked Above Average (2) for Safety. But, many of its peers pay even higher dividends. What's more, intermediate- and long-term capital appreciation potential is weak at this juncture. After rolling out our estimates to 2028-2030, the recent quotation is already well within our new range of $75-$105. The recent price also stands above the midpoint of our 18-month Target Price Range.

Zachary Hodgkinson *February 7, 2025*

(A) Diluted EPS. Excl. nonrec. gain (losses): '09, (25¢); '13, (83¢); '14, (59¢); '15, (25¢); '16, (28¢); '17, ($2.37); '18, (78¢); '19, $1.30; '20, (17¢); '21, (54¢). Next earnings report due in May. **(B)** Div'ds paid in early Mar., June, Sept., and Dec. ■ Div'd reinvestment plan avail. **(C)** Incl. def'd charges. In '23: $17.35/sh. **(D)** In mill. **(E)** Rate base: AL, MS, fair value; FL, GA, orig. cost. Allowed return on common eq. (blended): 12.5%; earned on avg. com. eq., '21: 12.8%. Regulatory Climate: GA, AL Above Average; MS, FL Average.

Company's Financial Strength	A
Stock's Price Stability	90
Price Growth Persistence	65
Earnings Predictability	90

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TXNM ENERGY NYSE-TXNM

RECENT PRICE 47.18 | P/E RATIO 17.1 (Trailing: 18.0 Median: 19.0) | RELATIVE P/E RATIO 0.94 | DIV'D YLD 3.5% | VALUE LINE

TIMELINESS 3 Raised 11/29/24
SAFETY 2 Raised 1/17/25
TECHNICAL 3 Lowered 11/29/24
BETA .90 (1.00 = Market)

18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$33-$49	$41 (-5%)

2027-29 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	65	(+40%)	*11%*
Low	45	(-5%)	*3%*

Institutional Decisions

	1Q2024	2Q2024	3Q2024
to Buy	152	156	153
to Sell	163	127	141
Hld's(000)	84833	87863	101664

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	© VALUE LINE PUB. LLC	27-29
High:	24.5	31.6	31.2	36.2	46.0	45.3	53.0	56.1	50.1	49.3	49.6	50.3								
Low:	20.1	23.5	24.4	29.2	33.3	33.8	39.7	27.1	43.8	43.4	41.4	34.6								
	22.65	19.01	19.31	21.35	16.85	17.42	18.03	18.07	17.11	18.14	18.04	18.30	17.74	20.74	26.21	21.50	*21.85*	*22.85*	Revenues per sh	*27.35*
	1.76	2.32	2.67	3.18	3.39	3.52	4.09	4.28	4.51	5.30	5.47	5.95	5.80	6.19	6.67	6.62	*6.85*	*7.25*	"Cash Flow" per sh	*8.65*
	.11	.58	.87	1.08	1.31	1.41	1.45	1.48	1.46	1.92	2.00	2.16	2.28	2.45	2.69	2.82	*2.75*	*2.85*	Earnings per sh [A]	*3.35*
	.61	.50	.50	.50	.58	.68	.76	.82	.90	.99	1.09	1.18	1.25	1.33	1.41	1.49	1.57	*1.65*	Div'd Decl'd per sh [B] ■	*1.94*
	3.99	3.32	3.25	4.10	3.88	4.37	5.78	7.01	7.53	6.28	6.29	7.74	7.91	10.89	10.63	11.93	*12.90*	*13.85*	Cap'l Spending per sh	*13.50*
	18.89	18.90	17.60	19.62	20.05	20.87	22.39	20.78	21.04	21.28	21.20	21.08	23.88	25.25	25.54	26.04	*27.40*	*28.80*	Book Value per sh [C]	*33.50*
	86.53	86.67	86.67	79.65	79.65	79.65	79.65	79.65	79.65	79.65	79.65	79.65	85.83	85.83	85.83	90.20	*91.00*	*92.00*	Common Shs Outst'g [D]	*95.00*
	NMF	18.1	14.0	14.5	15.0	16.1	18.7	18.7	22.4	20.4	19.4	22.2	19.6	19.9	17.4	16.3	*14.7*		Avg Ann'l P/E Ratio	*16.5*
	NMF	1.21	.89	.91	.95	.90	.98	.94	1.18	1.03	1.05	1.18	1.01	1.08	1.01	.91	*.81*		Relative P/E Ratio	*.90*
	4.9%	4.8%	4.1%	3.2%	3.0%	3.0%	2.8%	3.0%	2.8%	2.5%	2.8%	2.5%	2.8%	2.7%	3.0%	3.2%	3.9%		Avg Ann'l Div'd Yield	*3.5%*
							1435.9	1439.1	1363.0	1445.0	1436.6	1457.6	1523.0	1779.9	2249.6	1939.2	*1990*	*2100*	Revenues ($mill)	*2600*
							116.8	118.8	117.4	154.4	160.6	173.1	183.4	211.6	232.0	244.1	*250*	*265*	Net Profit ($mill)	*320*
							34.8%	36.9%	32.4%	33.0%	12.9%	8.1%	9.5%	13.4%	14.6%	13.6%	*14.5%*	*15.0%*	Income Tax Rate	*16.0%*
							10.7%	17.0%	11.0%	11.9%	12.1%	9.8%	8.9%	8.6%	9.0%	12.3%	*12.0%*	*13.0%*	AFUDC % to Net Profit	*13.0%*
							47.8%	54.1%	55.7%	56.1%	61.1%	59.8%	56.9%	61.8%	63.9%	64.2%	*66.0%*	*67.5%*	Long-Term Debt Ratio	*69.0%*
							51.9%	45.5%	44.0%	43.6%	38.6%	39.9%	42.9%	38.0%	36.0%	35.6%	*33.5%*	*32.0%*	Common Equity Ratio	*30.5%*
							3437.1	3633.3	3806.8	3887.5	4370.0	4207.7	4780.6	5698.6	6096.1	6602.3	*7400*	*8250*	Total Capital ($mill)	*10400*
							4270.0	4535.4	4904.7	4980.2	5234.6	5466.0	5965.1	6752.9	6972.8	7609.9	*8400*	*9300*	Net Plant ($mill)	*11500*
							5.1%	4.8%	4.7%	5.3%	5.0%	5.5%	4.9%	4.6%	4.9%	5.0%	*4.5%*	*4.5%*	Return on Total Cap'l	*4.5%*
							6.5%	7.1%	7.0%	9.0%	9.4%	10.2%	8.9%	9.7%	10.5%	10.3%	*10.0%*	*10.0%*	Return on Shr. Equity	*10.0%*
							6.5%	7.1%	7.0%	9.1%	9.5%	10.3%	8.9%	9.7%	10.6%	10.4%	*10.0%*	*10.0%*	Return on Com Equity [E]	*10.0%*
							3.2%	3.3%	2.8%	4.5%	4.5%	4.8%	4.1%	4.6%	5.1%	5.0%	*4.0%*	*4.0%*	Retained to Com Eq	*4.5%*
							51%	54%	61%	51%	53%	54%	54%	53%	52%	52%	*57%*	*58%*	All Div'ds to Net Prof	*58%*

CAPITAL STRUCTURE as of 9/30/24
Total Debt $5381.7 mill. **Due in 5 Yrs** $2177.6 mill.
LT Debt $4511.2 mill. **LT Interest** $195.0 mill.
(Total Interest Coverage: 2.3x)

Leases, Uncapitalized Annual rentals $12.3 mill.

Pension Assets-12/23 $448.6 mill.
Oblig. $461.2 mill.
Pfd Stock $11.5 mill. **Pfd Div'd** $.5 mill.

Common Stock 90,200,384 shs.
as of 10/25/24
MARKET CAP: $4.3 billion (Mid Cap)

ELECTRIC OPERATING STATISTICS

	2021	2022	2023
% Change Retail Sales (KWH)	1.0	5.2	1.0
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	1968	2139	2162
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	1.2	1.0	1.0
Fixed Charge Cov. (%)	317	289	230

ANNUAL RATES of change (per sh)

	Past 10 Yrs.	Past 5 Yrs.	Est'd '21-'23 to '27-'29
Revenues	2.0%	5.0%	*3.0%*
"Cash Flow"	7.0%	5.0%	*5.0%*
Earnings	7.5%	8.0%	*4.0%*
Dividends	9.0%	7.0%	*5.5%*
Book Value	2.5%	4.0%	*4.5%*

QUARTERLY REVENUES ($ mill.)

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	364.7	426.5	554.6	434.1	1779.9
2022	444.1	499.7	729.9	575.9	2249.6
2023	544.1	477.2	505.9	412.0	1939.2
2024	436.9	488.1	569.3	***495.7***	***1990***
2025	***475***	***510***	***590***	***525***	***2100***

EARNINGS PER SHARE [A]

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	.32	.55	1.37	.21	2.45
2022	.50	.57	1.46	.15	2.69
2023	.55	.55	1.54	.18	2.82
2024	.41	.60	1.43	***.31***	***2.75***
2025	***.42***	***.60***	***1.50***	***.33***	***2.85***

QUARTERLY DIVIDENDS PAID [B] ■

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	.3275	.3275	.3275	.3275	1.31
2022	.3475	.3475	.3475	.3475	1.39
2023	.3675	.3675	.3675	.3675	1.47
2024	.3875	.3875	.3875	.3875	1.55
2025	.4075				

% TOT. RETURN 12/24

	THIS STOCK	VL ARITH.* INDEX
1 yr.	25.3	13.6
3 yr.	21.5	14.7
5 yr.	14.6	70.9

Target Price Range 2027 2028 2029: 128, 96, 80, 64, 48, 40, 32, 24, 16, 12

LEGENDS: 28.6 x Dividends p sh; Relative Price Strength; Options: Yes; *Shaded area indicates recession*

Percent shares traded: 24, 16, 8

BUSINESS: TXNM Energy, Inc. (formerly PNM Resources) is a holding company with two regulated electric utilities. Public Service Company of New Mexico (PNM) serves about 550,000 customers in north central New Mexico, including Albuquerque and Santa Fe. Texas-New Mexico Power Company (TNMP) transmits and distributes power to more than 270,000 homes and businesses in Texas. Electric revenue: residential, 32%; commercial, 28%; indust'l, 7%; other, 33%. Fuel costs: 46% of revenues in 2023; reported depreciation rates: 2.67%-7.64%. Has about 1,600 employees. Chairman and CEO: Patricia K. Collawn. Incorporated: New Mexico. Address: 414 Silver Ave. SW, Albuquerque, New Mexico 87102-3289. Telephone: 505-241-2700. Internet: www.txnmenergy.com.

Last year was an interesting period of transition for TXNM Energy. From the start of 2024 through mid-year, this issue badly underperformed its peer group, with the share price dropping nearly 15% in the wake of the failed merger with Avangrid, which pulled the plug on its $50.30-per-share cash offer. That situation had dragged on since October of 2020, before Avangrid's parent company, the Spanish multinational Iberdrola, lost patience with the process. Oddly enough, it was Avangrid that ended up going private, as Iberdrola recently bought out the minority shareholders. Perhaps to put that saga in the rearview mirror, PNM Resources was rebranded as TXNM Energy. As management explains it, the shift was made to better reflect the changing dynamics of the company, where the Lewisville-Texas based TNMP subsidiary now makes up 40% of the holding company's rate base, and is its engine of growth. It's fair to ask, "what's in a name?" Yet, the tactic has seemingly worked. From its June low, the issue rallied 38% through the close of 2024 and has been one of the best performing utility stocks of late.

Longer-term prospects here appear decent relative to the electric utility peer group. The Public Service Company of New Mexico (PNM) subsidiary is suffering from a poor outcome in the latest general rate case decision, which was handed down about a year ago. On the positive side, PNM's state regulators did green light the utility's intermediate-term resources plan, which should get the New Mexico rate base growing again. Meanwhile, TNMP is expected to see nearly 13% annual rate-base growth for the 2024-2028 stretch, driven by above-average demographic trends and a vibrant Texas economy. For its part, leadership says that it is targeting 6%-7% earning growth over the 2024 to 2028 stretch, using the midpoint of its 2024 initial profit outlook of $2.70 per share as the starting point. We think that's a little aggressive and would be content if the company met our 5.5% annual share-earnings projection.

This equity is not timely. Annual total return prospects don't stand out either at the recent valuation. Moreover, its yield is 20 basis points below the peer median.

Anthony J. Glennon *January 17, 2025*

(A) Dil. EPS. Excl. nonrec. gain/(loss): '08, ($3.77); '10, ($1.36); '11, 88¢; '13, (16¢); '15, ($1.28); '17, (92¢); '18, (93¢); '19, ($1.19); '20, (13¢); '21, (18¢); '22, (72¢); '23, ($1.80). Excl. disc. op. gains: '08, 42¢; '09, 78¢. Next egs. report due early Feb. **(B)** Div'ds paid mid-Feb., May, Aug., & Nov. ■ Div'd reinv. plan avail. **(C)** Incl. def. charges/other intang. In '23: $15.45/sh. **(D)** In mill. **(E)** Rate base: net orig. cost. Rate allowed on com. eq. in NM in '23: 9.26%; in TX in '18: 9.65%; Regulatory Climate: NM, Below Average.; TX, Average.

Company's Financial Strength	B++
Stock's Price Stability	95
Price Growth Persistence	45
Earnings Predictability	100

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XCEL ENERGY NDQ-XEL

RECENT PRICE **65.14** | P/E RATIO **17.7** (Trailing: 18.8 Median: 20.0) | RELATIVE P/E RATIO **0.98** | DIV'D YLD **3.5%** | **VALUE LINE**

TIMELINESS 4 Lowered 10/11/24
SAFETY 2 Lowered 1/19/24
TECHNICAL 1 Raised 1/17/25
BETA .85 (1.00 = Market)

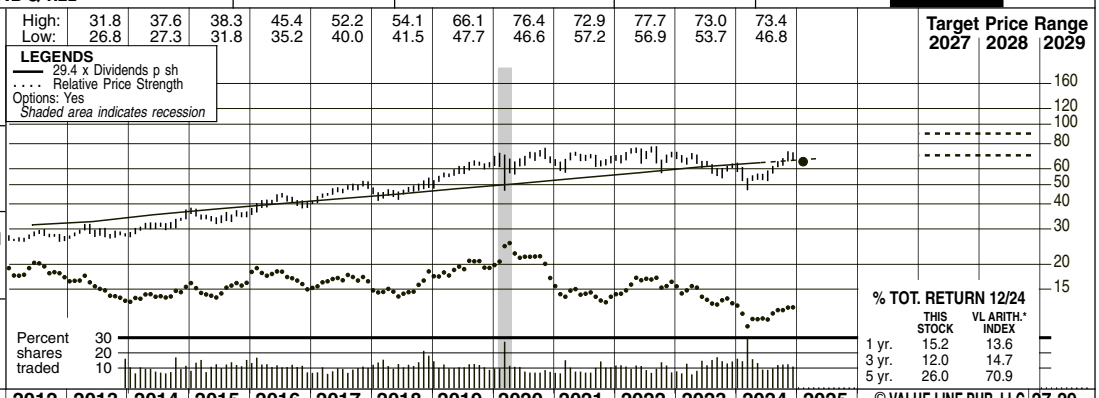
18-Month Target Price Range
Low-High **Midpoint (% to Mid)**
$54-$84 $69 (10%)

2027-29 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	90	(+40%)	*11%*
Low	70	(+5%)	*6%*

Institutional Decisions

	1Q2024	2Q2024	3Q2024
to Buy	433	467	518
to Sell	502	414	408
Hld's(000)	437447	437414	503378



2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	© VALUE LINE PUB. LLC	27-29
24.69	21.08	21.38	21.90	20.76	21.92	23.11	21.72	21.90	22.46	22.44	21.98	21.45	24.69	27.86	25.60	*24.55*	*27.05*	Revenues per sh	*31.10*
3.50	3.48	3.51	3.79	4.00	4.10	4.28	4.56	5.04	5.47	5.92	6.25	6.61	7.08	7.81	7.96	*8.40*	*9.10*	"Cash Flow" per sh	*10.95*
1.46	1.49	1.56	1.72	1.85	1.91	2.03	2.10	2.21	2.30	2.47	2.64	2.79	2.96	3.17	3.35	*3.55*	*3.80*	Earnings per sh [A]	*4.55*
.94	.97	1.00	1.03	1.07	1.11	1.20	1.28	1.36	1.44	1.52	1.62	1.72	1.83	1.95	2.08	2.19	*2.30*	Div'd Decl'd per sh [B] ■ †	*2.74*
4.66	3.91	4.60	4.53	5.27	6.82	6.33	7.26	6.42	6.54	7.70	8.05	9.99	7.80	8.44	10.55	*13.00*	*15.00*	Cap'l Spending per sh	*13.00*
15.35	15.92	16.76	17.44	18.19	19.21	20.20	20.89	21.73	22.56	23.78	25.24	27.12	28.70	30.34	31.74	*34.20*	*36.00*	Book Value per sh [C]	*41.90*
453.79	457.51	482.33	486.49	487.96	497.97	505.73	507.54	507.22	507.76	514.04	524.54	537.44	544.03	549.58	554.94	*575.00*	*580.00*	Common Shs Outst'g [D]	*595.00*
13.7	12.7	14.1	14.2	14.8	15.0	15.4	16.5	18.5	20.2	18.9	22.3	23.9	22.5	22.2	19.0	*16.8*		Avg Ann'l P/E Ratio	*17.5*
.82	.85	.90	.89	.94	.84	.81	.83	.97	1.02	1.02	1.19	1.23	1.22	1.28	1.06	*.93*		Relative P/E Ratio	*.95*
4.7%	5.1%	4.5%	4.2%	3.9%	3.9%	3.8%	3.7%	3.3%	3.1%	3.3%	2.7%	2.6%	2.8%	2.8%	3.3%	3.7%		Avg Ann'l Div'd Yield	*3.4%*
11686	11024	11107	11404	11537	11529	11526	13431	15310	14206	*14120*	*15700*	Revenues ($mill)	*18500*
1021.3	1063.6	1123.4	1171.0	1261.0	1372.0	1473.0	1597.0	1736.0	1851.0	*1995*	*2200*	Net Profit ($mill)	*2700*
33.9%	35.8%	34.1%	30.7%	12.6%	8.5%	--	--	--	--	*NMF*	*NMF*	Income Tax Rate	*NMF*
12.5%	7.7%	7.8%	9.4%	12.4%	8.3%	10.7%	6.2%	5.9%	7.7%	*10.0%*	*9.0%*	AFUDC % to Net Profit	*9.0%*
53.0%	54.1%	56.3%	55.9%	56.4%	56.8%	57.4%	58.2%	57.8%	58.6%	*58.0%*	*61.0%*	Long-Term Debt Ratio	*61.0%*
47.0%	45.9%	43.7%	44.1%	43.6%	43.2%	42.6%	41.8%	42.2%	41.4%	*42.0%*	*39.0%*	Common Equity Ratio	*39.0%*
21714	23092	25216	25975	28025	30646	34220	37391	39488	42529	*47100*	*53200*	Total Capital ($mill)	*64225*
28757	31206	32842	34329	36944	39483	42950	45457	48253	51642	*56225*	*62450*	Net Plant ($mill)	*74050*
6.0%	5.8%	5.7%	5.8%	5.7%	5.6%	5.4%	5.3%	5.5%	5.4%	*5.5%*	*5.0%*	Return on Total Cap'l	*5.5%*
10.0%	10.0%	10.2%	10.2%	10.3%	10.4%	10.1%	10.2%	10.4%	10.5%	*10.0%*	*10.5%*	Return on Shr. Equity	*11.0%*
10.0%	10.0%	10.2%	10.2%	10.3%	10.4%	10.1%	10.2%	10.4%	10.5%	*10.0%*	*10.5%*	Return on Com Equity [E]	*11.0%*
4.5%	4.3%	4.0%	3.9%	4.3%	4.4%	4.2%	4.2%	4.3%	4.3%	*4.0%*	*4.0%*	Retained to Com Eq	*4.5%*
55%	57%	61%	62%	58%	58%	58%	59%	58%	59%	*62%*	*60%*	All Div'ds to Net Prof	*60%*

CAPITAL STRUCTURE as of 9/30/24
Total Debt $28670 mill. **Due in 5 Yrs** $3790 mill.
LT Debt $27471 mill. **LT Interest** $1150 mill.
Incl. $218 mill. finance leases.
(Total Interest Coverage: 2.7x)

Leases, Uncapitalized Annual rentals $277 mill.
Pension Assets-12/23 $2690 mill.
Oblig. $2943 mill.
Pfd Stock None

Common Stock 574,241,745 shs.
as of 10/28/24
MARKET CAP: $37.4 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2021	2022	2023
% Change Retail Sales (KWH)	+1.4	+1.2	-1.6
Resid'l Revs. per KWH (¢)	12.94	13.41	13.80
C & I Revs. per KWH (¢)	8.73	9.02	8.82
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	19849	20346	20512
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	NA	NA	NA
Fixed Charge Cov. (%)	262	255	245

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '21-'23 to '27-'29
Revenues	2.0%	3.0%	*3.0%*
"Cash Flow"	7.0%	7.0%	*6.0%*
Earnings	5.5%	6.5%	*6.5%*
Dividends	6.0%	6.5%	*6.0%*
Book Value	5.0%	6.0%	*5.5%*

Calendar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	3541	3068	3467	3355	13431
2022	3751	3424	4082	4053	15310
2023	4080	3022	3662	3442	14206
2024	3649	3028	3644	*3799*	*14120*
2025	*4100*	*3400*	*4125*	*4075*	*15700*

Calendar	EARNINGS PER SHARE [A] Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	.67	.58	1.13	.58	2.96
2022	.70	.60	1.18	.69	3.17
2023	.76	.52	1.23	.83	3.35
2024	.88	.54	1.25	*.88*	*3.55*
2025	*.90*	*.65*	*1.35*	*.90*	*3.80*

Calendar	QUARTERLY DIVIDENDS PAID [B] ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	.43	.4575	.4575	.4575	1.80
2022	.4575	.4875	.4875	.4875	1.92
2023	.4875	.52	.52	.52	2.05
2024	.52	.5475	.5475	.5475	2.16
2025	.5475				

BUSINESS: Xcel Energy Inc. is the parent of Northern States Power Company (NSP), which supplies electricity to MN, WI, ND, SD & MI & gas to MN, WI, ND & MI; Public Service Company of Colorado (PSCo), which supplies electricity & gas to CO; & Southwestern Public Service Company (SPS), which supplies electricity to TX and NM. Customers: 3.8 mill. electric, 2.2 mill. gas. Electric revenues: resid'l, 31%; comm'l & ind'l, 50%; other, 19%. Purchases 34% of power, owns 66%. Total electric mix: wind, 29%; gas, 23%; coal, 13%, nuclear, 24%, solar/other, 11%. Fuel cost: 40% of revenues. '23 deprec. rate: 3.6%. Employs 11,311. Chrmn., President, and CEO: Robert Frenzel. Inc.: MN. Addr.: 414 Nicollet Mall, Minneapolis, MN 55401. Tel.: 612-330-5500. Int.: www.xcelenergy.com.

Xcel Energy stock has recovered nicely from the sharp sell-off of March, 2024, which coincided with Texas wildfires caused by downed wires. Even with the most recent industry correction, the share price is up nearly 40% from its 2024 nadir. The overreaction came at a time when the complete damages could not yet be assessed and the fires were still raging. It also came when the company was already mired in an ongoing investigation into the causes of the late 2021 Marshall fire in Colorado, with estimated damages of $2 billion. Subsequently, it has been found that physical damages in the Texas panhandle are likely to be around half of the company's $500 million of insurance per incident. The company has already settled nearly 50% of the cases and Texas law typically doesn't support major punitive damages.

Meanwhile, hundreds of Colorado wildfire claims have been combined into one case regarding liability, tentatively schedule for September of this year. Colorado law caps punitive damages at three times actual damages, so there is the potential for billions in payouts. But, there is also a fairly high hurdle for proving negligence in Colorado, which differs markedly from California law, for instance. Net of insurance, we'd be surprised if Xcel was liable for more than $1.5 billion, which is a manageable amount.

The company shored up its balance sheet with a substantial equity offering late last year. About 18 million shares were priced at $65.50 each, raising $1.2 billion. That the company was able to fetch a valuation of 18.5 times expected 2024 adjusted earnings of $3.55 per share is a testament to the Street's confidence in Xcel's ongoing business prospects. The company's diversification across several major service areas affords it financial resources few in the electric utility industry can match. Xcel always seems to have its ducks in a row in its rate cases and resource plans. It will likely find increased avenues of investment via mitigation work in response to these wildfire tragedies.

This stock is untimely. We'd want to see about a 10% pullback in the share price before comfortably recommending XEL to long-term utility investors.

Anthony J. Glennon *January 17, 2025*

(A) Diluted EPS. Excl. nonrec. gain/(losses): '10, 5¢; '15, (16¢); '17, (5¢); '23, (14¢); gain/(loss) on discontinued ops.: '09, (1¢); '10, 1¢. Qtly. EPS may not sum to full yr. due to rounding. Next egs. report due Feb. 6th.
(B) Div'ds typically paid mid-Jan., Apr., July, and Oct. ■ Div'd reinvestment plan available. † Shareholder investment plan available.
(C) Incl. intangibles. In '23: $2798 mill., $5.04/sh. **(D)** In mill. **(E)** Rate base: Varies. Rate allowed on common equity (blended): 9.6%. Regulatory Climate: Average.

Company's Financial Strength	A
Stock's Price Stability	95
Price Growth Persistence	55
Earnings Predictability	100

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Valley Energy, Inc. / Citizens' Electric Company of Lewisburg, PA / Wellsboro Electric Company
Indicated Common Equity Cost Rate
Through Use of a Risk Premium Model
Using an Adjusted Total Market Approach

Line No.		Proxy Group of Seven Natural Gas Distribution Companies	Proxy Group of Fifteen Electric Companies
1.	Prospective Yield on Aaa Rated Corporate Bonds (1)	5.35 %	5.35 %
2.	Adjustment to Reflect Yield Spread Between Aaa Rated Corporate Bonds and A2 Rated Public Utility Bonds (2)	0.38	0.38
3.	Adjusted Prospective Yield on A2 Rated Public Utility Bonds	5.73 %	5.73 %
4.	Adjustment to Reflect Bond Rating Difference of Proxy Group	0.07 (3)	0.13 (4)
5.	Adjusted Bond Yield	5.80 %	5.86 %
6.	Equity Risk Premium (5)	5.06	4.93
7.	Risk Premium Derived Common Equity Cost Rate	10.86 %	10.79 %

Notes: (1) Consensus forecast of Moody's Aaa Rated Corporate bonds from Blue Chip Financial Forecasts (see pages 7 and 8 of this Schedule).

(2) The average yield spread of A2 rated public utility bonds over Aaa rated corporate bonds of 0.38% from page 2 of this Schedule.

(3) Adjustment to reflect the A3 Moody's LT issuer rating of the Proxy Group of Seven Natural Gas Distribution Companies as shown on page 3 of this Schedule. The 0.07% upward adjustment is derived by taking 1/3 of the spread between A2 and Baa2 Public Utility Bonds (1/3 * 0.20% = 0.07%) as derived from page 2 of this Schedule.

(4) Adjustment to reflect the Baa1 Moody's LT issuer rating of the Proxy Group of Fifteen Electric Companies as shown on page 3 of this Schedule. The 0.13% upward adjustment is derived by taking 2/3 of the spread between A2 and Baa2 Public Utility Bonds (2/3 * 0.20% = 0.13%) as derived from page 2 of this Schedule.

(5) From page 5 of this Schedule.

Valley Energy, Inc. / Citizens' Electric Company of Lewisburg, PA / Wellsboro Electric Company
Interest Rates and Bond Spreads for
Moody's Corporate and Public Utility Bonds

Selected Bond Yields

	[1] Aaa Rated Corporate Bond	[2] A2 Rated Public Utility Bond	[3] Baa2 Rated Public Utility Bond
Feb-2025	5.32 %	5.73 %	5.90 %
Jan-2025	5.46	5.81	6.05
Dec-2024	5.20	5.58	5.77
Average	5.33 %	5.71 %	5.91 %

Selected Bond Spreads

A2 Rated Public Utility Bonds Over Aaa Rated Corporate Bonds: 0.38 % (1)

Baa2 Rated Public Utility Bonds Over A2 Rated Public Utility Bonds: 0.20 % (2)

Notes:
(1) Column [2] - Column [1].
(2) Column [3] - Column [2].

Source of Information:
Bloomberg Professional Services

Valley Energy, Inc. / Citizens' Electric Company of Lewisburg, PA / Wellsboro Electric Company
Comparison of Long-Term Issuer Ratings for the
Proxy Group of Forty-Nine Non-Price Regulated Companies

	Moody's Long-Term Issuer Rating February 2025		Standard & Poor's Long-Term Issuer Rating February 2025	
Proxy Group of Seven Natural Gas Distribution Companies	Long-Term Issuer Rating (1)	Numerical Weighting (2)	Long-Term Issuer Rating (1)	Numerical Weighting (2)
Atmos Energy Corporation	A1	5.0	A-	7.0
New Jersey Resources Corporation	A1	5.0	NR	- -
NiSource Inc.	Baa1	8.0	BBB+	8.0
Northwest Natural Holding Company	Baa1	8.0	A+	5.0
ONE Gas, Inc.	A3	7.0	A-	7.0
Southwest Gas Holdings, Inc.	Baa1	8.0	BBB	9.0
Spire Inc.	A1/A2	5.5	BBB+	8.0
Average	A3	6.6	A-	7.3

Proxy Group of Fifteen Electric Companies	Long-Term Issuer Rating (1)	Numerical Weighting (2)	Long-Term Issuer Rating (1)	Numerical Weighting (2)
Alliant Energy Corporation	Baa1	8.0	A/A-	6.5
Ameren Corporation	A3	7.0	BBB+	8.0
American Electric Power Corporation	Baa1	8.0	BBB+	8.0
Duke Energy Corporation	A3	7.0	BBB+	8.0
Edison International	Baa1	8.0	BBB	9.0
Entergy Corporation	Baa1	8.0	BBB+	8.0
Evergy, Inc.	Baa1	8.0	BBB+	8.0
IDACORP, Inc.	Baa1	8.0	BBB	9.0
North Western Corporation	Baa2	9.0	BBB	9.0
OGE Energy Corporation	A3	7.0	A-	7.0
Pinnacle West Capital Corporation	Baa1	8.0	BBB+	8.0
Portland General Electric Company	A3	7.0	BBB+	8.0
Southern Company	A2/A3	6.5	A-	7.0
TXNM Energy, Inc.	Baa1/Baa2	8.5	BBB+/BBB	8.5
Xcel Energy Inc.	A3	7.0	BBB+	8.0
Average	Baa1	7.7	BBB+	8.0

Notes:
(1) Ratings are that of the average of each company's utility operating subsidiaries.
(2) From page 4 of this Schedule.

Source Information: Moody's Investors Service
Standard & Poor's Global Utilities Rating Service

Numerical Assignment for Moody's and Standard & Poor's Bond Ratings

Moody's Bond Rating	Numerical Bond Weighting	Standard & Poor's Bond Rating
Aaa	1	AAA
Aa1	2	AA+
Aa2	3	AA
Aa3	4	AA-
A1	5	A+
A2	6	A
A3	7	A-
Baa1	8	BBB+
Baa2	9	BBB
Baa3	10	BBB-
Ba1	11	BB+
Ba2	12	BB
Ba3	13	BB-
B1	14	B+
B2	15	B
B3	16	B-

Valley Energy, Inc. / Citizens' Electric Company of Lewisburg, PA / Wellsboro Electric Company
Judgment of Equity Risk Premium for the
Proxy Group of Forty-Nine Non-Price Regulated Companies

Line No.		Proxy Group of Seven Natural Gas Distribution Companies	Proxy Group of Fifteen Electric Companies
1.	Calculated equity risk premium based on the total market using the beta approach (1)	5.68 %	5.25 %
2.	Mean equity risk premium based on a study using the holding period returns of public utilities with A2 rated bonds (2)	4.76	4.76
3.	Predicted Equity Risk Premium Based on Regression Analysis of 848 Fully-Litigated Natural Gas Rate Cases (3)	4.73	NA
4.	Predicted Equity Risk Premium Based on Regression Analysis of 1,257 Fully-Litigated Electric Rate Cases (4)	NA	4.77
5.	Average equity risk premium	5.06 %	4.93 %

Notes: (1) From page 6 of this Schedule.
(2) From page 9 of this Schedule.
(3) From page 10 of this Schedule.
(3) From page 11 of this Schedule.

Valley Energy, Inc. / Citizens' Electric Company of Lewisburg, PA / Wellsboro Electric Company
Derivation of Equity Risk Premium Based on the Total Market Approach
Using the Beta for the
Proxy Group of Seven Natural Gas Distribution Companies and Proxy Group of Fifteen Electric Companies

Line No.	Equity Risk Premium Measure	Proxy Group of Seven Natural Gas Distribution Companies	Proxy Group of Fifteen Electric Companies
1.	Kroll Equity Risk Premium (1)	6.10 %	6.10 %
2.	Regression on Kroll Risk Premium Data (2)	6.82	6.82
3.	Kroll Equity Risk Premium based on PRPM (3)	7.32	7.32
4	Equity Risk Premium Based on Value Line Summary and Index (4)	5.85	5.85
5.	Equity Risk Premium Based on Bloomberg, Value Line, and S&P Global Market Intelligence S&P 500 Companies (5)	9.88	9.88
6.	Conclusion of Equity Risk Premium	7.19 %	7.19 %
7.	Adjusted Beta (6)	0.79	0.73
8.	Forecasted Equity Risk Premium	5.68 %	5.25 %

Notes:

(1) Based on the arithmetic mean historical monthly returns on large company common stocks from Kroll Cost of Capital Navigator and Bloomberg Professional Services minus the arithmetic mean monthly yield of Moody's average Aaa and Aa2 corporate bonds from 1928-2024.

(2) This equity risk premium is based on a regression of the monthly equity risk premiums of large company common stocks relative to Moody's average Aaa and Aa2 rated corporate bond yields from 1928-2024 referenced in Note 1 above. Using the equation generated from the regression, an expected equity risk premium is calculated using the average consensus forecast of Aaa corporate bonds of 5.35% (from page 1 of this Schedule).

(3) The Predictive Risk Premium Model (PRPM) is discussed in the accompanying direct testimony. The Ibbotson equity risk premium based on the PRPM is derived by applying the PRPM to the monthly risk premiums between Ibbotson large company common stock monthly returns and average Aaa and Aa corporate monthly bond yields, from January 1928 through February 2025.

(4) The equity risk premium based on the Value Line Summary and Index is derived by subtracting the average consensus forecast of Aaa corporate bonds of 5.35% (from page 1 of this Schedule) from the projected 3-5 year total annual market return of 11.20% (described fully in note 1 on page 2 of Schedule DWD-5).

(5) Using data from the Bloomberg Professional Services, Value Line, and S&P Global Market Intelligence for the S&P 500 for the S&P 500, an expected total return of 15.23% was derived based upon expected dividend yields as a proxy for income returns and long-term earnings growth estimates as a proxy for capital appreciation. Subtracting the average consensus forecast of Aaa corporate bonds of 5.35% results in an expected equity risk premium of 9.88%.

(6) Average of mean and median beta for each proxy group from page 1 of Schedule DWD-5.

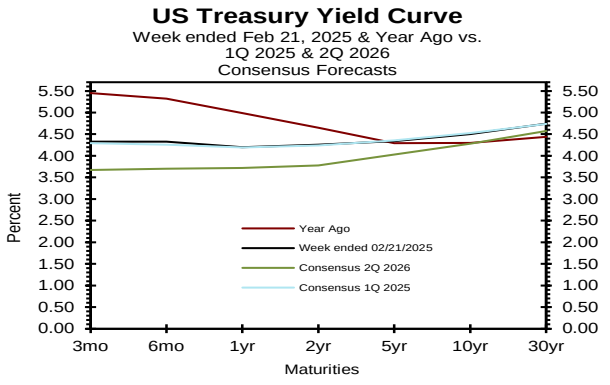
Sources of Information:

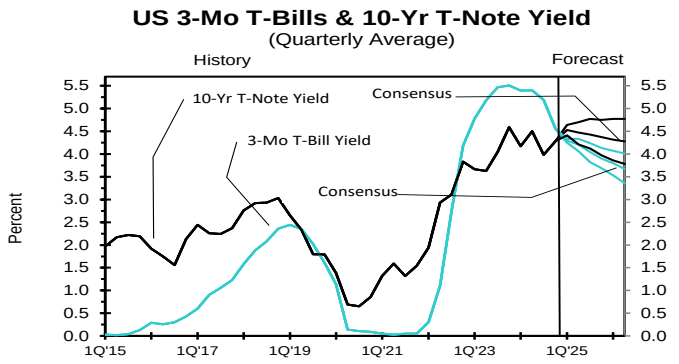
Kroll Cost of Capital Navigator
Industrial Manual and Mergent Bond Record Monthly Update.
Value Line Summary and Index
Blue Chip Financial Forecasts, November 27, 2024 and February 28, 2025
S&P Capital IQ
Bloomberg Professional Services

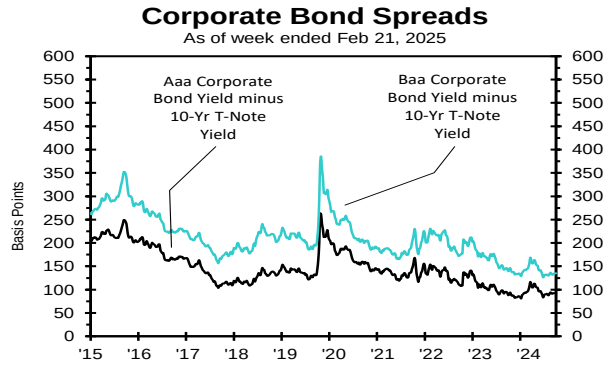
Consensus Forecasts of U.S. Interest Rates and Key Assumptions

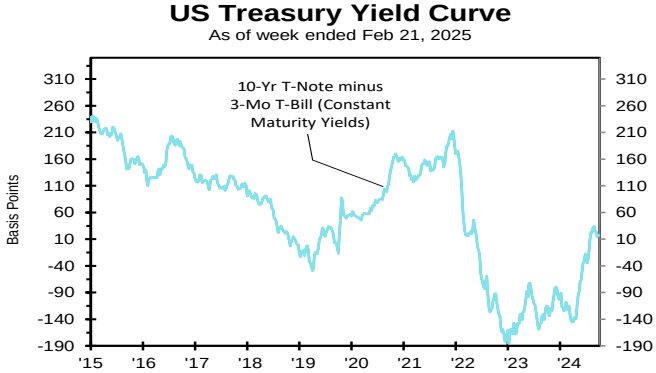
	History								Consensus Forecasts-Quarterly Avg.					
	Average For Week Ending				Average For Month			*Latest Qtr*	1Q	2Q	3Q	4Q	1Q	2Q
Interest Rates	Feb 21	Feb 14	Feb 7	Jan 31	Jan	Dec	Nov	4Q 2024	2025	2025	2025	2025	2026	2026
Federal Funds Rate	4.33	4.33	4.33	4.33	4.33	4.48	4.64	4.65	**4.4**	**4.3**	**4.1**	**4.0**	**3.9**	**3.8**
Prime Rate	7.50	7.50	7.50	7.50	7.50	7.65	7.81	7.82	**7.5**	**7.4**	**7.3**	**7.1**	**7.0**	**6.9**
SOFR	4.34	4.33	4.34	4.36	4.32	4.53	4.64	4.67	**4.3**	**4.3**	**4.1**	**4.0**	**3.9**	**3.7**
Commercial Paper, 1-mo.	4.32	4.31	4.30	4.30	4.32	4.50	4.62	4.63	**4.3**	**4.3**	**4.1**	**4.0**	**3.9**	**3.7**
Treasury bill, 3-mo.	4.33	4.35	4.34	4.31	4.34	4.39	4.62	4.58	**4.3**	**4.2**	**4.0**	**3.9**	**3.8**	**3.7**
Treasury bill, 6-mo.	4.33	4.32	4.28	4.27	4.26	4.32	4.43	4.40	**4.3**	**4.1**	**4.0**	**3.9**	**3.8**	**3.7**
Treasury bill, 1 yr.	4.20	4.26	4.20	4.15	4.18	4.23	4.33	4.25	**4.2**	**4.1**	**4.0**	**3.9**	**3.8**	**3.7**
Treasury note, 2 yr.	4.26	4.30	4.23	4.19	4.27	4.23	4.26	4.15	**4.2**	**4.1**	**4.0**	**3.9**	**3.9**	**3.8**
Treasury note, 5 yr.	4.34	4.38	4.30	4.33	4.43	4.25	4.23	4.13	**4.4**	**4.3**	**4.2**	**4.1**	**4.1**	**4.0**
Treasury note, 10 yr.	4.50	4.53	4.49	4.55	4.63	4.39	4.36	4.28	**4.5**	**4.5**	**4.4**	**4.4**	**4.3**	**4.3**
Treasury note, 30 yr.	4.74	4.74	4.70	4.78	4.85	4.58	4.54	4.50	**4.7**	**4.7**	**4.7**	**4.6**	**4.6**	**4.6**
Corporate Aaa bond	5.43	5.45	5.41	5.47	5.55	5.29	5.23	5.20	**5.5**	**5.4**	**5.4**	**5.4**	**5.4**	**5.4**
Corporate Baa bond	5.85	5.88	5.84	5.88	5.97	5.71	5.66	5.63	**6.2**	**6.2**	**6.2**	**6.2**	**6.2**	**6.2**
State & Local bonds	4.18	4.19	4.16	4.14	4.18	4.10	4.08	4.08	**4.4**	**4.4**	**4.4**	**4.4**	**4.4**	**4.4**
Home mortgage rate	6.85	6.87	6.89	6.95	6.96	6.72	6.81	6.65	**6.9**	**6.8**	**6.7**	**6.6**	**6.5**	**6.5**
	History								Consensus Forecasts-Quarterly					
	1Q	2Q	3Q	4Q	1Q	2Q	3Q	4Q	1Q	2Q	3Q	4Q	1Q	2Q
Key Assumptions	2023	2023	2023	2023	2024	2024	2024	2024	2025	2025	2025	2025	2026	2026
Fed's AFE $ Index	115.5	114.6	115.0	116.6	115.5	117.3	114.9	117.9	**119.9**	**120.0**	**119.3**	**118.5**	**118.0**	**117.5**
Real GDP	2.8	2.4	4.4	3.2	1.6	3.0	3.1	2.3	**2.3**	**2.0**	**1.9**	**1.9**	**2.0**	**2.0**
GDP Price Index	3.6	1.9	3.2	1.5	3.0	2.5	1.9	2.4	**2.7**	**2.5**	**2.5**	**2.5**	**2.5**	**2.2**
Consumer Price Index	3.7	3.0	3.5	2.8	3.7	2.8	1.4	3.0	**3.5**	**2.7**	**2.6**	**2.6**	**2.6**	**2.5**
PCE Price Index	3.9	2.9	2.7	1.7	3.4	2.5	1.5	2.4	**2.8**	**2.6**	**2.5**	**2.5**	**2.5**	**2.3**

Forecasts for interest rates and the Federal Reserve's Advanced Foreign Economies Index represent averages for the quarter. Forecasts for Real GDP, GDP Price Index, CPI and PCE Price Index are seasonally adjusted annual rates of change (saar). Individual panel members' forecasts are on pages 4 through 9. Historical data: Treasury rates from the Federal Reserve Board's H.15; AAA-AA and A-BBB corporate bond yields from Bank of America-Merrill Lynch and are 15+ years, yield to maturity; State and local bond yields from Bank of America-Merrill Lynch, A-rated, yield to maturity; Mortgage rates from Freddie Mac, 30-year, fixed; SOFR from the New York Fed. All interest rate data are sourced from Haver Analytics. Historical data for Fed's Major Currency Index are from FRSR H.10. Historical data for Real GDP, GDP Price Index and PCE Price Index are from the Bureau of Economic Analysis (BEA). Consumer Price Index history is from the Department of Labor's Bureau of Labor Statistics (BLS).









Long-Range Survey:

The table below contains the results of our twice-annual long-range CONSENSUS survey. There are also Top 10 and Bottom 10 averages for each variable. Shown are consensus estimates for the years 2026 through 2030 and averages for the five-year periods 2026-2030 and 2031-2035. Apply these projections cautiously. Few if any economic, demographic and political forces can be evaluated accurately over such long time spans.

		Average For The Year					Five-Year Averages	
		2026	2027	2028	2029	2030	2026-2030	2031-2035
1. Federal Funds Rate	**CONSENSUS**	**3.4**	**3.3**	**3.3**	**3.2**	**3.2**	**3.3**	**3.2**
	Top 10 Average	3.7	3.7	3.6	3.7	3.7	3.7	3.6
	Bottom 10 Average	3.0	2.9	2.9	2.9	2.8	2.9	2.9
2. Prime Rate	**CONSENSUS**	**6.5**	**6.4**	**6.4**	**6.4**	**6.3**	**6.4**	**6.3**
	Top 10 Average	6.8	6.8	6.7	6.8	6.7	6.7	6.7
	Bottom 10 Average	6.2	6.1	6.1	6.0	5.9	6.1	5.9
3. SOFR	**CONSENSUS**	**3.3**	**3.3**	**3.3**	**3.3**	**3.3**	**3.3**	**3.3**
	Top 10 Average	3.6	3.6	3.6	3.6	3.6	3.6	3.6
	Bottom 10 Average	3.1	3.0	3.0	2.9	2.9	3.0	2.9
4. Commercial Paper, 1-Mo	**CONSENSUS**	**3.4**	**3.4**	**3.4**	**3.4**	**3.3**	**3.4**	**3.3**
	Top 10 Average	3.6	3.6	3.6	3.6	3.6	3.6	3.6
	Bottom 10 Average	3.2	3.1	3.1	3.0	3.0	3.1	3.0
5. Treasury Bill Yield, 3-Mo	**CONSENSUS**	**3.3**	**3.3**	**3.2**	**3.2**	**3.2**	**3.3**	**3.2**
	Top 10 Average	3.6	3.6	3.5	3.6	3.6	3.6	3.5
	Bottom 10 Average	3.1	3.0	2.9	2.9	2.8	2.9	2.8
6. Treasury Bill Yield, 6-Mo	**CONSENSUS**	**3.4**	**3.3**	**3.3**	**3.2**	**3.2**	**3.3**	**3.2**
	Top 10 Average	3.6	3.6	3.6	3.6	3.6	3.6	3.6
	Bottom 10 Average	3.1	3.0	3.0	2.9	2.8	3.0	2.9
7. Treasury Bill Yield, 1-Yr	**CONSENSUS**	**3.4**	**3.4**	**3.3**	**3.3**	**3.3**	**3.3**	**3.3**
	Top 10 Average	3.7	3.7	3.6	3.6	3.6	3.6	3.6
	Bottom 10 Average	3.2	3.1	3.0	3.0	2.9	3.0	2.9
8. Treasury Note Yield, 2-Yr	**CONSENSUS**	**3.6**	**3.6**	**3.5**	**3.5**	**3.5**	**3.5**	**3.5**
	Top 10 Average	3.9	3.9	3.9	3.9	3.9	3.9	3.9
	Bottom 10 Average	3.3	3.2	3.1	3.1	3.0	3.1	3.0
9. Treasury Note Yield, 5-Yr	**CONSENSUS**	**3.8**	**3.8**	**3.8**	**3.8**	**3.7**	**3.8**	**3.8**
	Top 10 Average	4.2	4.3	4.3	4.3	4.3	4.3	4.3
	Bottom 10 Average	3.4	3.4	3.3	3.3	3.2	3.3	3.2
10. Treasury Note Yield, 10-Yr	**CONSENSUS**	**4.0**	**4.1**	**4.0**	**4.0**	**3.9**	**4.0**	**4.0**
	Top 10 Average	4.5	4.6	4.5	4.5	4.5	4.5	4.5
	Bottom 10 Average	3.6	3.5	3.4	3.4	3.3	3.5	3.4
11. Treasury Bond Yield, 30-Yr	**CONSENSUS**	**4.3**	**4.4**	**4.3**	**4.3**	**4.2**	**4.3**	**4.2**
	Top 10 Average	4.7	4.8	4.8	4.8	4.8	4.8	4.7
	Bottom 10 Average	3.9	3.9	3.8	3.8	3.7	3.8	3.8
12. Corporate Aaa Bond Yield	**CONSENSUS**	**5.1**	**5.2**	**5.2**	**5.1**	**5.1**	**5.2**	**5.1**
	Top 10 Average	5.5	5.7	5.6	5.6	5.6	5.6	5.5
	Bottom 10 Average	4.8	4.8	4.7	4.7	4.6	4.7	4.6
13. Corporate Baa Bond Yield	**CONSENSUS**	**6.0**	**6.1**	**6.0**	**6.0**	**6.0**	**6.0**	**5.9**
	Top 10 Average	6.4	6.6	6.5	6.5	6.4	6.5	6.4
	Bottom 10 Average	5.7	5.7	5.6	5.6	5.5	5.6	5.5
14. State & Local Bonds Yield	**CONSENSUS**	**4.1**	**4.3**	**4.2**	**4.2**	**4.3**	**4.2**	**4.1**
	Top 10 Average	4.5	4.6	4.6	4.6	4.6	4.6	4.6
	Bottom 10 Average	3.8	3.9	3.9	3.9	3.9	3.9	3.6
15. Home Mortgage Rate	**CONSENSUS**	**6.2**	**6.1**	**6.0**	**6.0**	**5.9**	**6.0**	**5.9**
	Top 10 Average	6.6	6.6	6.5	6.4	6.4	6.5	6.4
	Bottom 10 Average	5.7	5.7	5.6	5.5	5.4	5.6	5.4
A. Fed's AFE Nominal $ Index	**CONSENSUS**	**115.5**	**115.0**	**114.5**	**113.9**	**113.2**	**114.4**	**112.6**
	Top 10 Average	117.0	116.3	115.8	115.3	114.8	115.8	114.6
	Bottom 10 Average	113.9	113.6	113.1	112.5	111.8	113.0	110.9
		Year-Over-Year, % Change					Five-Year Averages	
		2026	2027	2028	2029	2030	2026-2030	2031-2035
B. Real GDP	**CONSENSUS**	**1.9**	**2.0**	**2.0**	**2.0**	**2.0**	**2.0**	**1.9**
	Top 10 Average	2.2	2.3	2.3	2.2	2.2	2.2	2.2
	Bottom 10 Average	1.7	1.7	1.8	1.7	1.7	1.7	1.7
C. GDP Chained Price Index	**CONSENSUS**	**2.2**	**2.2**	**2.2**	**2.2**	**2.2**	**2.2**	**2.1**
	Top 10 Average	2.4	2.3	2.3	2.3	2.3	2.3	2.3
	Bottom 10 Average	2.1	2.0	2.0	2.0	2.0	2.0	2.0
D. Consumer Price Index	**CONSENSUS**	**2.4**	**2.3**	**2.2**	**2.2**	**2.2**	**2.2**	**2.2**
	Top 10 Average	2.6	2.5	2.4	2.5	2.4	2.5	2.4
	Bottom 10 Average	2.1	2.0	2.0	2.0	2.0	2.0	2.0
E. PCE Price Index	**CONSENSUS**	**2.2**	**2.2**	**2.1**	**2.1**	**2.1**	**2.2**	**2.1**
	Top 10 Average	2.5	2.3	2.3	2.3	2.3	2.3	2.3
	Bottom 10 Average	2.0	2.0	1.9	2.0	2.0	2.0	2.0

Projected Market Appreciation of the S&P Utility Index
Derivation of Mean Equity Risk Premium Based Studies
Using Holding Period Returns and
Projected Market Appreciation of the S&P Utility Index

Line No.		Implied Equity Risk Premium
1.	Historical Equity Risk Premium (1)	4.16 %
2.	Regression of Historical Equity Risk Premium (2)	4.80
3	Forecasted Equity Risk Premium Based on PRPM (3)	5.07
4.	Forecasted Equity Risk Premium based on Projected Total Return on the S&P Utilities Index (Bloomberg, Value Line, and S&P Capital IQ Data) (4)	5.00
5.	Average Equity Risk Premium (5)	4.76 %

Notes: (1) Based on S&P Public Utility Index monthly total returns and Moody's Public Utility Bond average monthly yields from 1928-2024. Holding period returns are calculated based upon income received (dividends and interest) plus the relative change in the market value of a security over a one-year holding period.

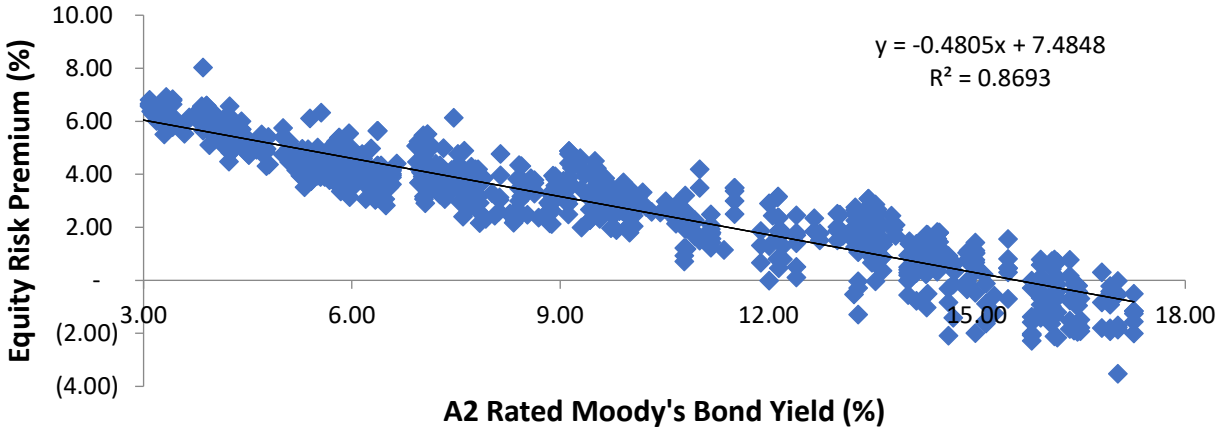
(2) This equity risk premium is based on a regression of the monthly equity risk premiums of the S&P Utility Index relative to Moody's A2 rated public utility bond yields from 1928 - 2024 referenced in note 1 above. Using the equation generated from the regression, an expected equity risk premium is calculated using the prospective A2 rated public utility bond yield of 5.73% (from line 3, page 1 of this Schedule).

(3) The Predictive Risk Premium Model (PRPM) is applied to the risk premium of the monthly total returns of the S&P Utility Index and the monthly yields on Moody's A2 rated public utility bonds from January 1928 - February 2025.

(4) Using data from Bloomberg, Value Line, and S&P Capital IQ for the S&P Utilities Index, an expected return of 10.73% was derived based on expected dividend yields as a proxy for income returns and long-term growth estimates as a proxy for market appreciation. Subtracting the expected A2 rated public utility bond yield of 5.73%, calculated on line 3 of page 1 of this Schedule results in an equity risk premium of 5.00%. (10.73% - 5.73% = 5.00%).

(5) Average of lines 1 through 4.

Valley Energy, Inc. / Citizens' Electric Company of Lewisburg, PA / Wellsboro Electric Company
Prediction of Equity Risk Premiums Relative to
Moody's A2 Rated Utility Bond Yields - Natural Gas Utilities



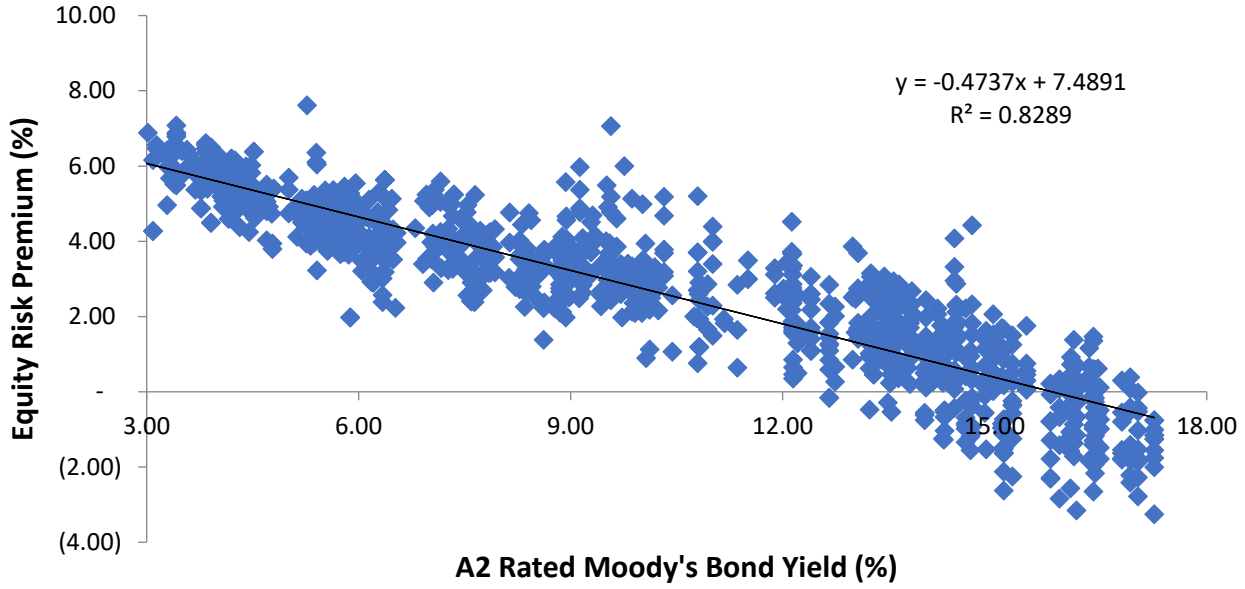
Constant	Slope	Prospective A2 Rated Utility Bond (1)	Equity Risk Premium
7.4848 %	-0.480	5.73 %	4.73 %

Notes:

(1) From line 3 of page 1 of this Schedule.

Source of Information: Regulatory Research Associates.

Valley Energy, Inc. / Citizens' Electric Company of Lewisburg, PA / Wellsboro Electric Company
Prediction of Equity Risk Premiums Relative to
Moody's A2 Rated Utility Bond Yields - Electric Utilities



Constant	Slope	Prospective A2 Rated Utility Bond (1)	Equity Risk Premium
7.4891 %	-0.4737	5.73 %	4.77 %

Notes:

(1) From line 3 of page 1 of this Schedule.

Source of Information: Regulatory Research Associates.

Valley Energy, Inc. / Citizens' Electric Company of Lewisburg, PA / Wellsboro Electric Company
Indicated Common Equity Cost Rate Through Use
of the Traditional Capital Asset Pricing Model (CAPM) and Empirical Capital Asset Pricing Model (ECAPM)

Proxy Group of Seven Natural Gas Distribution Companies

	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]
Proxy Group of Seven Natural Gas Distribution Companies	Value Line Adjusted Beta	Bloomberg Adjusted Beta	Average Beta	Market Risk Premium (1)	Risk-Free Rate (2)	Traditional CAPM Cost Rate	ECAPM Cost Rate	Indicated Common Equity Cost Rate (3)
Atmos Energy Corporation	0.90	0.60	0.75	8.15 %	4.55 %	10.66 %	11.17 %	10.92 %
New Jersey Resources Corporation	1.00	0.60	0.80	8.15	4.55	11.07	11.48	11.27
NiSource Inc.	0.95	0.61	0.78	8.15	4.55	10.91	11.36	11.13
Northwest Natural Holding Company	0.90	0.69	0.80	8.15	4.55	11.07	11.48	11.27
ONE Gas, Inc.	0.85	0.62	0.74	8.15	4.55	10.58	11.11	10.85
Southwest Gas Holdings, Inc.	0.95	0.85	0.90	8.15	4.55	11.89	12.09	11.99 (4)
Spire Inc.	0.90	0.65	0.78	8.15	4.55	10.91	11.36	11.13
Mean			0.79			11.01 %	11.44 %	11.10 %
Median			0.78			10.91 %	11.36 %	11.13 %
Average of Mean and Median			0.79			10.96 %	11.40 %	11.12 %

Notes on page 2 of this Schedule.

Proxy Group of Fifteen Electric Companies

	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]
Proxy Group of Fifteen Electric Companies	Value Line Adjusted Beta	Bloomberg Adjusted Beta	Average Beta	Market Risk Premium (1)	Risk-Free Rate (2)	Traditional CAPM Cost Rate	ECAPM Cost Rate	Indicated Common Equity Cost Rate (3)
Alliant Energy Corporation	0.90	0.54	0.72	8.15 %	4.55 %	10.42 %	10.99 %	10.70 %
Ameren Corporation	0.90	0.52	0.71	8.15	4.55	10.34	10.93	10.63
American Electric Power Corporation	0.85	0.45	0.65	8.15	4.55	9.85	10.56	10.21
Duke Energy Corporation	0.90	0.43	0.66	8.15	4.55	9.93	10.62	10.28
Edison International	1.05	0.66	0.86	8.15	4.55	11.56	11.85	11.70
Entergy Corporation	1.00	0.56	0.78	8.15	4.55	10.91	11.36	11.13
Evergy, Inc.	0.95	0.54	0.75	8.15	4.55	10.66	11.17	10.92
IDACORP, Inc.	0.85	0.51	0.68	8.15	4.55	10.09	10.75	10.42
North Western Corporation	1.00	0.69	0.84	8.15	4.55	11.40	11.72	11.56
OGE Energy Corporation	1.05	0.65	0.85	8.15	4.55	11.48	11.78	11.63
Pinnacle West Capital Corporation	0.95	0.51	0.73	8.15	4.55	10.50	11.05	10.78
Portland General Electric Company	0.95	0.61	0.78	8.15	4.55	10.91	11.36	11.13
Southern Company	0.95	0.45	0.70	8.15	4.55	10.26	10.87	10.56
TXNM Energy, Inc.	0.90	0.42	0.66	8.15	4.55	9.93	10.62	10.28
Xcel Energy Inc.	0.85	0.40	0.62	8.15	4.55	9.60	10.38	9.99
Mean			0.73			10.52 %	11.07 %	10.79 %
Median			0.72			10.42 %	10.99 %	10.70 %
Average of Mean and Median			0.73			10.47 %	11.03 %	10.75 %

Notes on page 2 of this Schedule.

Valley Energy, Inc. / Citizens' Electric Company of Lewisburg, PA / Wellsboro Electric Company
Notes to Accompany the Application of the CAPM and ECAPM

Notes:

(1) The market risk premium (MRP) is derived by using five different measures from four sources: Kroll, Value Line, Bloomberg, and S&P Capital IQ as illustrated below:

Measure 1: Kroll Arithmetic Mean MRP (1926-2024)

Arithmetic Mean Monthly Returns for Large Stocks 1926-2024:	12.29 %
Arithmetic Mean Income Returns on Long-Term Government Bonds:	4.99
MRP based on Kroll Historical Data:	7.31 %

Measure 2: Application of a Regression Analysis to Kroll Historical Data

(1926-2024)	7.94 %

Measure 3: Application of the PRPM to Kroll Historical Data

(January 1926 - February 2025)	8.18 %

Measure 4: Value Line Projected MRP (Thirteen weeks ending February 28, 2025)

Total projected return on the market 3-5 years hence*:	11.20 %
Risk-Free Rate (see notes 2 and 3):	4.55
MRP based on Value Line Summary & Index:	6.65 %

*Forcasted 3-5 year capital appreciation plus expected dividend yield

Measure 5: Bloomberg, Value Line, and S&P Capital IQ Projected Return on the Market based on the S&P 500

Total return on the Market based on the S&P 500:	15.23 %
Risk-Free Rate (see notes 2 and 3):	4.55
MRP based on Bloomberg, Value Line, and S&P Capital IQ data	10.68 %

Average of all MRP Measures:	8.15 %

(2) For reasons explained in the Direct Testimony, the appropriate risk-free rate for cost of capital purposes is the average forecast of 30 year Treasury Bonds per the consensus of nearly 50 economists reported in Blue Chip Financial Forecasts. (See pages 7 and 8 of Schedule DWD-4.) The projection of the risk-free rate is illustrated below:

First Quarter 2025	4.70 %
Second Quarter 2025	4.70
Third Quarter 2025	4.70
Fourth Quarter 2025	4.60
First Quarter 2026	4.60
Second Quarter 2026	4.60
2026-2030	4.30
2031-2035	4.20
	4.55 %

(3) Average of Column 6 and Column 7.

Sources of Information:
Value Line Summary and Index
Blue Chip Financial Forecasts, November 27, 2024 and February 28, 2025
Kroll Cost of Capital Navigator
S&P Capital IQ
Bloomberg Professional Services

Valley Energy, Inc. / Citizens' Electric Company of Lewisburg, PA / Wellsboro Electric Company
Basis of Selection of the Group of Non-Price Regulated Companies
Comparable in Total Risk to the Proxy Group of Seven Natural Gas Distribution Companies

The criteria for selection of the proxy group of non-price regulated companies comparable in total risk to the proxy group of seven natural gas distribution companies was that the non-price regulated companies be domestic and reported in Value Line Investment Survey (Standard Edition).

The proxy group of non-price regulated companies was selected based on the unadjusted beta range of 0.64 - 0.92 and residual standard error of the regression range of 2.8368 - 3.3832 of the proxy group of seven natural gas distribution companies.

These ranges are based upon plus or minus two standard deviations of the unadjusted beta and standard error of the regression. Plus or minus three standard deviations captures 95.50% of the distribution of unadjusted betas and residual standard errors of the regression.

The standard deviation of the proxy group of seven natural gas distribution companies' residual standard error of the regression is 0.1366. The standard deviation of the standard error of the

$$\text{Standard Deviation of the Std. Err. of the Regr.} = \frac{\text{Standard Error of the Regression}}{\sqrt{2N}}$$

where: N = number of observations. Since Value Line betas are derived from weekly price change observations over a period of five years, N = 259

$$\text{Thus,} \quad 0.1366 = \frac{3.1100}{\sqrt{518}} = \frac{3.1100}{22.7596}$$

Source of Information: Value Line Proprietary Database, December 2024.
Value Line Investment Survey (Standard Edition).

Valley Energy, Inc. / Citizens' Electric Company of Lewisburg, PA / Wellsboro Electric Company
Basis of Selection of the Group of Non-Price Regulated Companies
Comparable in Total Risk to the Proxy Group of Fifteen Electric Companies

The criteria for selection of the proxy group of non-price regulated companies comparable in total risk to the proxy group of fifteen electric companies was that the non-price regulated companies be domestic and reported in Value Line Investment Survey (Standard Edition).

The proxy group of non-price regulated companies was selected based on the unadjusted beta range of 0.71 - 0.97 and residual standard error of the regression range of 2.6065 - 3.1089 of the proxy group of fifteen electric companies.

These ranges are based upon plus or minus two standard deviations of the unadjusted beta and standard error of the regression. Plus or minus three standard deviations captures 95.50% of the distribution of unadjusted betas and residual standard errors of the regression.

The standard deviation of the proxy group of fifteen electric companies' residual standard error of the regression is 0.1256. The standard deviation of the standard error of the regression is

$$\text{Standard Deviation of the Std. Err. of the Regr.} = \frac{\text{Standard Error of the Regression}}{\sqrt{2N}}$$

where: N = number of observations. Since Value Line betas are derived from weekly price change observations over a period of five years, N = 259

$$\text{Thus,} \quad 0.1256 = \frac{2.8577}{\sqrt{518}} = \frac{2.8577}{22.7596}$$

Source of Information: Value Line Proprietary Database, December 2024.
Value Line Investment Survey (Standard Edition).

Valley Energy, Inc. / Citizens' Electric Company of Lewisburg, PA / Wellsboro Electric Company
Basis of Selection of Comparable Risk
Domestic Non-Price Regulated Companies

Proxy Group of Seven Natural Gas Distribution Companies	[1] Value Line Adjusted Beta	[2] Unadjusted Beta	[3] Residual Standard Error of the Regression	[4] Standard Deviation of Beta
Atmos Energy Corporation	0.85	0.75	2.8989	0.0647
New Jersey Resources Corporation	0.95	0.91	3.0464	0.0680
NiSource Inc.	0.90	0.83	2.6470	0.0591
Northwest Natural Holding Company	0.85	0.71	3.3761	0.0754
ONE Gas, Inc.	0.85	0.71	3.2540	0.0726
Southwest Gas Holdings, Inc.	0.90	0.80	3.4852	0.0778
Spire Inc.	0.85	0.74	3.0953	0.0691
Average	0.88	0.78	3.1100	0.0700
Beta Range (+/- 2 std. Devs. of Beta)	0.64	0.92		
2 std. Devs. of Beta	0.14			
Residual Std. Err. Range (+/- 2 std. Devs. of the Residual Std. Err.)	2.8368	3.3832		
Std. dev. of the Res. Std. Err.	0.1366			
2 std. devs. of the Res. Std. Err.	0.2732			

Proxy Group of Fifteen Electric Companies	[1] Value Line Adjusted Beta	[2] Unadjusted Beta	[3] Residual Standard Error of the Regression	[4] Standard Deviation of Beta
Alliant Energy Corporation	0.90	0.79	2.8682	0.0640
Ameren Corporation	0.90	0.78	2.7253	0.0608
American Electric Power Corporation	0.80	0.68	2.8069	0.0627
Duke Energy Corporation	0.90	0.80	2.8177	0.0629
Edison International	1.00	0.96	3.0475	0.0680
Entergy Corporation	0.95	0.91	2.8593	0.0638
Evergy, Inc.	0.95	0.88	2.9738	0.0664
IDACORP, Inc.	0.85	0.71	2.7358	0.0611
North Western Corporation	0.95	0.89	2.8815	0.0643
OGE Energy Corporation	1.05	1.05	2.8365	0.0633
Pinnacle West Capital Corporation	0.95	0.88	3.0813	0.0688
Portland General Electric Company	0.90	0.83	2.9422	0.0657
Southern Company	0.95	0.87	2.7873	0.0622
TXNM Energy, Inc.	0.90	0.78	2.6718	0.0596
Xcel Energy Inc.	0.85	0.73	2.8298	0.0632
Average	0.92	0.84	2.8577	0.0638
Beta Range (+/- 2 std. Devs. of Beta)	0.71	0.97		
2 std. Devs. of Beta	0.13			
Residual Std. Err. Range (+/- 2 std. Devs. of the Residual Std. Err.)	2.6065	3.1089		
Std. dev. of the Res. Std. Err.	0.1256			
2 std. devs. of the Res. Std. Err.	0.2512			

Source of Information: Value Line Proprietary Database, December 2024.

Valley Energy, Inc. / Citizens' Electric Company of Lewisburg, PA / Wellsboro Electric Company
Proxy Group of Non-Price Regulated Companies
Comparable in Total Risk to the
Proxy Group of Seven Natural Gas Distribution Companies and Proxy Group of Fifteen Electric Companies

Proxy Group of Forty-Nine Non-Price Regulated Companies	[1] Value Line Adjusted Beta	[2] Unadjusted Beta	[3] Residual Standard Error of the Regression	[4] Standard Deviation of Beta
Abbott Labs.	0.90	0.79	2.9573	0.0660
AbbVie Inc.	0.85	0.70	3.1365	0.0700
Air Products & Chem.	0.90	0.83	3.0324	0.0677
Alphabet Inc.	0.90	0.81	3.1907	0.0712
Altria Group	0.85	0.76	2.8948	0.0646
Apple Inc.	0.95	0.91	3.2127	0.0717
Assurant Inc.	0.90	0.79	3.0394	0.0679
AutoZone Inc.	0.95	0.88	3.2399	0.0723
Booz Allen Hamilton	0.85	0.74	3.2930	0.0735
Brady Corp.	0.95	0.90	2.8860	0.0644
BWX Technologies	0.80	0.68	3.2662	0.0729
CACI Int'l	0.90	0.80	3.0359	0.0678
Casey's Gen'l Stores	0.90	0.79	3.1661	0.0707
Cencora	0.80	0.66	2.9646	0.0662
CSW Industrials	0.90	0.77	3.2779	0.0732
CVS Health	0.90	0.79	3.3646	0.0751
Danaher Corp.	0.90	0.81	3.0286	0.0676
Dolby Labs.	0.95	0.87	2.9508	0.0659
Exponent, Inc.	0.95	0.88	3.3456	0.0747
Fastenal Co.	0.90	0.80	2.9253	0.0653
Franklin Electric	0.90	0.82	2.9333	0.0655
GATX Corp.	0.95	0.90	2.9875	0.0667
Henry (Jack) & Assoc	0.85	0.74	3.1928	0.0713
Hunt (J.B.)	0.95	0.91	3.2647	0.0729
Huntington Ingalls	0.95	0.89	3.3736	0.0753
L3Harris Technologie	0.90	0.83	3.1556	0.0711
Landstar System	0.80	0.65	2.8665	0.0640
Lockheed Martin	0.85	0.75	2.8741	0.0642
McKesson Corp.	0.85	0.70	3.1485	0.0703
Microsoft Corp.	0.90	0.78	2.8520	0.0637
MSC Industrial Direc	0.90	0.84	2.9545	0.0660
Oracle Corp.	0.85	0.70	3.0995	0.0692
O'Reilly Automotive	0.90	0.84	3.0259	0.0676
OSI Systems	0.90	0.81	3.2160	0.0718
Packaging Corp.	0.95	0.85	2.8607	0.0639
Pfizer, Inc.	0.80	0.67	3.1709	0.0708
Philip Morris Int'l	0.95	0.87	2.8750	0.0642
Prestige Consumer	0.85	0.75	3.3470	0.0747
Selective Ins. Group	0.85	0.74	2.9941	0.0668
Service Corp. Int'l	0.90	0.84	3.1842	0.0711
Sherwin-Williams	0.95	0.90	2.9254	0.0653
Smith (A.O.)	0.90	0.79	3.0828	0.0688
Thermo Fisher Sci.	0.85	0.77	2.8565	0.0638
UniFirst Corp.	0.90	0.81	3.0115	0.0672
UnitedHealth Group	0.95	0.90	3.1445	0.0702
Universal Corp.	0.80	0.68	3.2233	0.0720
VeriSign Inc.	0.90	0.80	2.8857	0.0644
Waters Corp.	0.95	0.86	3.2280	0.0721
Watsco, Inc.	0.85	0.76	3.1218	0.0697
Average	0.89	0.80	3.0829	0.0688
Proxy Group of Seven Natural Gas Distribution Companies	0.88	0.78	3.1100	0.0700

Source of Information: Value Line Proprietary Database, December 2024.

Valley Energy, Inc. / Citizens' Electric Company of Lewisburg, PA / Wellsboro Electric Company
Proxy Group of Non-Price Regulated Companies
Comparable in Total Risk to the
Proxy Group of Seven Natural Gas Distribution Companies and Proxy Group of Fifteen Electric Companies

Proxy Group of Forty-Seven Non-Price Regulated Companies	[1] Value Line Adjusted Beta	[2] Unadjusted Beta	[3] Residual Standard Error of the Regression	[4] Standard Deviation of Beta
3M Company	0.95	0.90	2.8096	0.0627
Abbott Laboratories	0.90	0.79	2.9573	0.0660
Agilent Technologies, Inc.	0.95	0.86	2.8368	0.0633
Air Products and Chemicals, Inc.	0.90	0.83	3.0324	0.0677
Allstate Corporation	1.00	0.94	2.7930	0.0624
Altria Group, Inc.	0.85	0.76	2.8948	0.0646
Analog Devices, Inc.	1.00	0.95	2.8971	0.0647
Archer-Daniels-Midland Company	0.95	0.89	2.7243	0.0608
Assurant, Inc.	0.90	0.79	3.0394	0.0679
Brady Corporation	0.95	0.90	2.8860	0.0644
Broadridge Financial Solutions, Inc.	0.90	0.82	2.7633	0.0617
Brown & Brown, Inc.	0.95	0.91	2.6119	0.0583
Brown-Forman Corporation 'B'	0.90	0.80	2.7338	0.0610
CACI International Inc	0.90	0.80	3.0359	0.0678
Cisco Systems, Inc.	0.85	0.75	2.8343	0.0633
Danaher Corporation	0.90	0.81	3.0286	0.0676
Dolby Laboratories, Inc.	0.95	0.87	2.9508	0.0659
Expeditors International	0.95	0.91	2.6741	0.0597
FactSet Research Systems Inc.	1.00	0.95	2.7486	0.0614
Fastenal Company	0.90	0.80	2.9253	0.0653
Federal Signal Corporation	0.95	0.91	2.7333	0.0610
Franklin Electric Co., Inc.	0.90	0.82	2.9333	0.0655
GATX Corporation	0.95	0.90	2.9875	0.0667
Gentex Corporation	1.00	0.93	2.6082	0.0582
Home Depot, Inc.	0.95	0.90	2.6215	0.0585
Ingredion, Inc.	0.90	0.79	2.6281	0.0587
Innospec Inc.	1.00	0.94	3.0243	0.0675
International Business Machines Corporation	0.90	0.85	2.6691	0.0596
Juniper Networks, Inc.	1.00	0.93	2.8368	0.0633
Lockheed Martin Corporation	0.85	0.75	2.8741	0.0642
Microsoft Corporation	0.90	0.78	2.8520	0.0637
Motorola Solutions, Inc.	0.95	0.85	2.7315	0.0610
MSA Safety, Inc.	0.95	0.92	3.0893	0.0690
MSC Industrial Direct Co., Inc.	0.90	0.84	2.9545	0.0660
O'Reilly Automotive, Inc.	0.90	0.84	3.0259	0.0676
Packaging Corporation of America	0.95	0.85	2.8607	0.0639
Philip Morris International Inc.	0.95	0.87	2.8750	0.0642
Selective Insurance Group, Inc.	0.85	0.74	2.9941	0.0668
Sensient Technologies Corporation	0.90	0.85	2.8202	0.0630
Sherwin-Williams Company	0.95	0.90	2.9254	0.0653
Smith Corporation (A.O.)	0.90	0.79	3.0828	0.0688
Texas Instruments Incorporated	0.85	0.77	2.7711	0.0619
Thermo Fisher Scientific Inc.	0.85	0.77	2.8565	0.0638
UniFirst Corporation	0.90	0.81	3.0115	0.0672
VeriSign, Inc.	0.90	0.80	2.8857	0.0644
Verisk Analytics, Inc.	0.90	0.78	2.7553	0.0615
Zoetis, Inc.	1.00	0.96	2.8162	0.0629
Average	0.92	0.85	2.8596	0.0638
Proxy Group of Fifteen Electric Companies	0.92	0.84	2.8577	0.0638

Source of Information: Value Line Proprietary Database, December 2024.

Valley Energy, Inc. / Citizens' Electric Company of Lewisburg, PA / Wellsboro Electric Company
Summary of Cost of Equity Models Applied to
Proxy Group of Non-Price Regulated Companies
Comparable in Total Risk to the
Proxy Group of Seven Natural Gas Distribution Companies and Proxy Group of Fifteen Electric Companies

Principal Methods	Proxy Group of Forty-Nine Non-Price Regulated Companies	Proxy Group of Forty-Seven Non-Price Regulated Companies
Discounted Cash Flow Model (DCF) (1)	11.87 %	11.17 %
Risk Premium Model (RPM) (2)	12.27	12.29
Capital Asset Pricing Model (CAPM) (3)	11.75	11.89
Mean	11.96 %	11.78 %
Median	11.87 %	11.89 %
Average of Mean and Median	11.92 %	11.84 %

Notes:
(1) From pages 2-3 of this Schedule.
(2) From page 4 of this Schedule.
(3) From pages 8-9 of this Schedule.

Valley Energy, Inc. / Citizens' Electric Company of Lewisburg, PA / Wellsboro Electric Company
DCF Results for the Proxy Group of Non-Price-Regulated Companies Comparable in Total Risk to the
Proxy Group of Seven Natural Gas Distribution CompaniesProxy Group of Forty-Nine Non-Price Regulated Companies

	[1]	[2]	[3]	[4]	[5]	[6]	[7]
Proxy Group of Forty-Nine Non-Price Regulated Companies	Average Dividend Yield	Value Line Projected Five Year Growth in EPS	Zack's Five Year Projected Growth Rate in EPS	S&P Capital IQ Projected Five Year Growth in EPS	Average Projected Five Year Growth Rate in EPS	Adjusted Dividend Yield	Indicated Common Equity Cost Rate (1)
Abbott Labs.	1.94 %	4.50 %	10.40 %	9.57 %	8.16 %	2.02 %	10.18 %
AbbVie Inc.	3.59	4.00	10.20	11.68	8.63	3.74	12.37
Air Products & Chem.	2.30	10.50	7.90	10.34	9.58	2.41	11.99
Alphabet Inc.	0.42	13.50	15.60	16.59	15.23	0.45	15.68
Altria Group	7.64	6.00	3.50	4.31	4.60	7.82	12.42
Apple Inc.	0.41	9.00	13.80	9.53	10.78	0.43	11.21
Assurant Inc.	1.51	9.50	NA	NA	9.50	1.58	11.08
AutoZone Inc.	-	11.50	11.80	12.73	12.01	-	NA
Booz Allen Hamilton	1.69	10.50	14.00	13.50	12.67	1.80	14.47
Brady Corp.	1.29	15.50	NA	11.00	13.25	1.38	14.63
BWX Technologies	0.87	9.00	10.10	10.92	10.01	0.91	10.92
CACI Int'l	-	4.50	14.10	14.08	10.89	-	NA
Casey's Gen'l Stores	0.48	12.00	12.60	12.53	12.38	0.51	12.89
Cencora	0.91	6.50	12.10	11.70	10.10	0.96	11.06
CSW Industrials	0.27	13.50	NA	12.50	13.00	0.29	13.29
CVS Health	4.93	0.50	11.30	23.31	11.70	5.22	16.92
Danaher Corp.	0.57	2.00	10.20	9.43	7.21	0.59	7.80
Dolby Labs.	1.64	9.50	NA	NA	9.50	1.72	11.22
Exponent, Inc.	1.32	7.50	NA	NA	7.50	1.37	8.87
Fastenal Co.	2.28	9.00	9.80	9.26	9.35	2.39	11.74
Franklin Electric	1.05	7.50	12.00	12.00	10.50	1.11	11.61
GATX Corp.	1.52	10.50	NA	NA	10.50	1.60	12.10
Henry (Jack) & Assoc	1.33	6.50	8.60	8.63	7.91	1.38	9.29
Hunt (J.B.)	1.02	6.00	16.40	12.48	11.63	1.08	12.71
Huntington Ingalls	2.88	10.00	11.10	11.08	10.73	3.03	13.76
L3Harris Technologie	2.25	9.00	7.30	7.88	8.06	2.34	10.40
Landstar System	0.84	6.00	NA	11.00	8.50	0.88	9.38
Lockheed Martin	2.78	12.00	7.80	6.45	8.75	2.90	11.65
McKesson Corp.	0.48	10.00	14.30	14.04	12.78	0.51	13.29
Microsoft Corp.	0.78	14.50	14.40	12.97	13.96	0.83	14.79
MSC Industrial Direc	4.21	0.50	NA	NA	0.50	4.22	4.72 (2)
Oracle Corp.	0.93	10.00	10.20	11.22	10.47	0.98	11.45
O'Reilly Automotive	-	10.50	12.80	12.12	11.81	-	NA
OSI Systems	-	10.50	12.90	14.05	12.48	-	NA
Packaging Corp.	2.21	9.00	8.30	11.31	9.54	2.32	11.86
Pfizer, Inc.	6.57	2.50	13.80	2.56	6.29	6.78	13.07
Philip Morris Int'l	4.09	5.00	8.20	9.87	7.69	4.25	11.94
Prestige Consumer	-	5.50	7.00	7.67	6.72	-	NA
Selective Ins. Group	1.68	10.50	NA	16.40	13.45	1.79	15.24
Service Corp. Int'l	1.59	4.50	10.80	10.77	8.69	1.66	10.35
Sherwin-Williams	0.89	12.00	9.80	9.56	10.45	0.94	11.39
Smith (A.O.)	1.97	9.00	12.00	12.00	11.00	2.08	13.08
Thermo Fisher Sci.	0.32	6.00	7.70	9.55	7.75	0.33	8.08
UniFirst Corp.	0.68	8.50	NA	NA	8.50	0.71	9.21
UnitedHealth Group	1.61	11.00	12.40	15.03	12.81	1.71	14.52
Universal Corp.	6.04	13.50	NA	NA	13.50	6.45	19.95 (2)
VeriSign Inc.	-	12.00	NA	NA	12.00	-	NA
Waters Corp.	-	6.50	7.80	8.29	7.53	-	NA
Watsco, Inc.	2.19	7.00	NA	NA	7.00	2.27	9.27
	NA = Not Available					Mean	11.93 %
						Median	11.80 %
						Average of Mean and Median	11.87 %

Notes:

(1) The application of the DCF model to the domestic, non-price regulated comparable risk companies is identical to the application of the DCF to the Utility Proxy Groups. The dividend yield is derived by using the 60 day average price and the spot indicated dividend as of 02/28/2025. The dividend yield is then adjusted by 1/2 the average projected growth rate in EPS, which is calculated by averaging the 5 year projected growth in EPS provided by Value Line, www.zacks.com, and S&P Capital IQ (excluding any negative growth rates) and then adding that growth rate to the adjusted dividend yield.

(2) Results were excluded from the final average and median as they were more than two standard deviations from the proxy group's mean.

Source of Information:

Value Line Investment Survey.
www.zacks.com, Downloaded on 02/28/2025
S&P Capital IQ

Valley Energy, Inc. / Citizens' Electric Company of Lewisburg, PA / Wellsboro Electric Company
DCF Results for the Proxy Group of Non-Price-Regulated Companies Comparable in Total Risk to the
Proxy Group of Seven Natural Gas Distribution CompaniesProxy Group of Forty-Nine Non-Price Regulated Companies

	[1]	[2]	[3]	[4]	[5]	[6]	[7]
Proxy Group of Forty-Seven Non-Price Regulated Companies	Average Dividend Yield	Value Line Projected Five Year Growth in EPS	Zack's Five Year Projected Growth Rate in EPS	S&P Capital IQ Projected Five Year Growth in EPS	Average Projected Five Year Growth Rate in EPS	Adjusted Dividend Yield	Indicated Common Equity Cost Rate (1)
3M Company	2.08 %	31.00 %	5.80 %	(6.19) %	18.40 %	2.27 %	20.67 % (2)
Abbott Laboratories	1.94	4.50	10.40	9.57	8.16	2.02	10.18
Agilent Technologies, Inc.	0.71	6.50	6.60	7.56	6.89	0.73	7.62
Air Products and Chemicals, Inc.	2.30	10.50	7.90	10.34	9.58	2.41	11.99
Allstate Corporation	2.08	29.00	9.80	NMF	19.40	2.28	21.68 (2)
Altria Group, Inc.	7.64	6.00	3.50	4.31	4.60	7.82	12.42
Analog Devices, Inc.	1.82	9.00	12.00	16.87	12.62	1.93	14.55
Archer-Daniels-Midland Company	4.10	3.00	7.30	7.27	5.86	4.22	10.08
Assurant, Inc.	1.51	9.50	NA	NA	9.50	1.58	11.08
Brady Corporation	1.29	15.50	NA	11.00	13.25	1.38	14.63
Broadridge Financial Solutions, Inc.	1.51	9.50	NA	NA	9.50	1.58	11.08
Brown & Brown, Inc.	0.56	12.50	9.10	10.06	10.55	0.59	11.14
Brown-Forman Corporation 'B'	2.50	14.00	3.20	0.17	5.79	2.57	8.36
CACI International Inc	-	4.50	14.10	14.08	10.89	-	NA
Cisco Systems, Inc.	2.70	3.50	5.10	4.47	4.36	2.76	7.12
Danaher Corporation	0.57	2.00	10.20	9.43	7.21	0.59	7.80
Dolby Laboratories, Inc.	1.64	9.50	NA	NA	9.50	1.72	11.22
Expeditors International	1.28	(0.50)	4.30	10.18	7.24	1.33	8.57
FactSet Research Systems Inc.	0.88	9.00	9.20	9.86	9.35	0.92	10.27
Fastenal Company	2.28	9.00	9.80	9.26	9.35	2.39	11.74
Federal Signal Corporation	0.59	13.50	14.00	12.00	13.17	0.63	13.80
Franklin Electric Co., Inc.	1.05	7.50	12.00	12.00	10.50	1.11	11.61
GATX Corporation	1.52	10.50	NA	NA	10.50	1.60	12.10
Gentex Corporation	1.75	12.50	14.30	14.33	13.71	1.87	15.58
Home Depot, Inc.	2.27	6.50	7.10	4.04	5.88	2.34	8.22
Ingredion, Inc.	2.36	9.50	11.00	11.00	10.50	2.48	12.98
Innospec Inc.	1.42	7.50	NA	7.50	7.50	1.47	8.97
International Business Machines Corporation	2.82	3.00	4.20	7.49	4.90	2.89	7.79
Juniper Networks, Inc.	2.38	6.50	12.40	16.12	11.67	2.52	14.19
Lockheed Martin Corporation	2.78	12.00	7.80	6.45	8.75	2.90	11.65
Microsoft Corporation	0.78	14.50	14.40	12.97	13.96	0.83	14.79
Motorola Solutions, Inc.	0.94	10.00	8.40	7.39	8.60	0.98	9.58
MSA Safety, Inc.	1.23	8.00	NA	NA	8.00	1.28	9.28
MSC Industrial Direct Co., Inc.	4.21	0.50	NA	NA	0.50	4.22	4.72 (2)
O'Reilly Automotive, Inc.	-	10.50	12.80	12.12	11.81	-	NA
Packaging Corporation of America	2.21	9.00	8.30	11.31	9.54	2.32	11.86
Philip Morris International Inc.	4.09	5.00	8.20	9.87	7.69	4.25	11.94
Selective Insurance Group, Inc.	1.68	10.50	NA	16.40	13.45	1.79	15.24
Sensient Technologies Corporation	2.22	2.50	NA	14.00	8.25	2.31	10.56
Sherwin-Williams Company	0.89	12.00	9.80	9.56	10.45	0.94	11.39
Smith Corporation (A.O.)	1.97	9.00	12.00	12.00	11.00	2.08	13.08
Texas Instruments Incorporated	2.86	3.00	11.60	10.95	8.52	2.98	11.50
Thermo Fisher Scientific Inc.	0.32	6.00	7.70	9.55	7.75	0.33	8.08
UniFirst Corporation	0.68	8.50	NA	NA	8.50	0.71	9.21
VeriSign, Inc.	-	12.00	NA	NA	12.00	-	NA
Verisk Analytics, Inc.	0.63	11.00	12.00	11.98	11.66	0.67	12.33
Zoetis, Inc.	1.19	7.50	9.30	9.24	8.68	1.24	9.92
	NA = Not Available					Mean	11.11 %
						Median	11.22 %
						Average of Mean and Median	11.17 %

Notes:

(1) The application of the DCF model to the domestic, non-price regulated comparable risk companies is identical to the application of the DCF to the Utility Proxy Groups. The dividend yield is derived by using the 60 day average price and the spot indicated dividend as of 02/28/2025. The dividend yield is then adjusted by 1/2 the average projected growth rate in EPS, which is calculated by averaging the 5 year projected growth in EPS provided by Value Line, www.zacks.com, and S&P Capital IQ (excluding any negative growth rates) and then adding that growth rate to the adjusted dividend yield.

(2) Results were excluded from the final average and median as they were more than two standard deviations from the proxy group's mean.

Source of Information:

Value Line Investment Survey.
www.zacks.com, Downloaded on 02/28/2025
S&P Capital IQ

Valley Energy, Inc. / Citizens' Electric Company of Lewisburg, PA / Wellsboro Electric Company
Indicated Common Equity Cost Rate
Through Use of a Risk Premium Model
Using an Adjusted Total Market Approach

Line No.		Proxy Group of Forty-Nine Non-Price Regulated Companies	Proxy Group of Forty-Seven Non-Price Regulated Companies
1.	Prospective Yield on Baa2 Rated Corporate Bonds (1)	6.14 %	6.14
2.	Adjustment to Reflect Bond rating Difference of Non-Price Regulated Companies (2)	(0.14)	(0.18)
3.	Adjusted Bond Yield	6.01	5.96
4.	Equity Risk Premium (3)	6.26	6.33
5.	Risk Premium Derived Common Equity Cost Rate	12.27 %	12.29

Notes: (1) Average forecast of Baa corporate bonds based upon the consensus of nearly 50 economists reported in Blue Chip Financial Forecasts dated November 27, 2024 and February 28, 2025 (see pages 7 and 8 of Schedule DWD-4). The estimates are detailed below.

First Quarter 2025	6.20 %
Second Quarter 2025	6.20
Third Quarter 2025	6.20
Fourth Quarter 2025	6.20
First Quarter 2026	6.20
Second Quarter 2026	6.20
2026-2030	6.00
2031-2035	5.90
Average	6.14 %

(2) The average yield spread of Baa2 rated corporate bonds over A2 corporate bonds for the three months ending February 2025. To reflect the A3/Baa1 average rating of the Proxy Group of Forty-Nine Non-Price Regulated Companies, the yield on the Baa corporate bond must be adjusted by one-half the spread between A2 and Baa2 corporate bond yields. Further, to reflect the A3 average rating of the Proxy Group of Forty-Seven Non-Price Regulated Companies, the yield on the Baa corporate bond must be adjusted by two-thirds the spread between A2 and Baa2 corporate bond yields, both shown below:

	A2 Corp. Bond Yield	Baa2 Corp. Bond Yield	Spread
Feb-25	5.66 %	5.92 %	0.26 %
Jan-25	5.80	6.08	0.28
Dec-24	5.53	5.80	0.27
		Average yield spread	0.27
		1/2 of spread	0.14
		2/3 of spread	0.18

(3) From page 7 of this Schedule.

Valley Energy, Inc. / Citizens' Electric Company of Lewisburg, PA / Wellsboro Electric Company
Comparison of Long-Term Issuer Ratings for the
Proxy Group of Forty-Nine Non-Price Regulated Companies and Proxy Group of Forty-Seven Non-Price Regulated Companies

Proxy Group of Forty-Nine Non-Price Regulated Companies	Moody's Long-Term Issuer Rating February 2025		Standard & Poor's Long-Term Issuer Rating February 2025	
	Long-Term Issuer Rating	Numerical Weighting (1)	Long-Term Issuer Rating	Numerical Weighting (1)
Abbott Labs.	Aa3	4.0	AA-	4.0
AbbVie Inc.	A3	7.0	A-	7.0
Air Products & Chem.	A2	6.0	A	6.0
Alphabet Inc.	Aa2	3.0	AA+	2.0
Altria Group	A3	7.0	BBB	9.0
Apple Inc.	Aaa	1.0	AA+	2.0
Assurant Inc.	Baa2	9.0	BBB	9.0
AutoZone Inc.	Baa1	8.0	BBB	9.0
Booz Allen Hamilton	NA	--	NA	--
Brady Corp.	NA	--	NA	--
BWX Technologies	Ba2	12.0	BB	12.0
CACI Int'l	NA	--	BB+	11.0
Casey's Gen'l Stores	NA	--	NA	--
Cencora	Baa2	9.0	BBB+	8.0
CSW Industrials	NA	--	NA	--
CVS Health	Baa3	10.0	BBB	9.0
Danaher Corp.	A3	7.0	A-	7.0
Dolby Labs.	NA	--	NA	--
Exponent, Inc.	NA	--	NA	--
Fastenal Co.	NA	--	NA	--
Franklin Electric	NA	--	NA	--
GATX Corp.	Baa2	9.0	BBB	9.0
Henry (Jack) & Assoc	NA	--	NA	--
Hunt (J.B.)	Baa1	8.0	BBB+	8.0
Huntington Ingalls	Baa3	10.0	BBB-	10.0
L3Harris Technologie	Baa2	9.0	BBB	9.0
Landstar System	NA	--	NA	--
Lockheed Martin	A2	6.0	A-	7.0
McKesson Corp.	A3	7.0	BBB+	8.0
Microsoft Corp.	Aaa	1.0	AAA	1.0
MSC Industrial Direc	NA	--	NA	--
Oracle Corp.	Baa2	9.0	BBB	9.0
O'Reilly Automotive	Baa1	8.0	BBB	9.0
OSI Systems	NA	--	NA	--
Packaging Corp.	Baa2	9.0	BBB	9.0
Pfizer, Inc.	A2	6.0	A	6.0
Philip Morris Int'l	A2	6.0	A-	7.0
Prestige Consumer	NA	--	BB	12.0
Selective Ins. Group	Baa2	9.0	BBB	9.0
Service Corp. Int'l	Ba3	13.0	BB+	11.0
Sherwin-Williams	Baa2	9.0	BBB	9.0
Smith (A.O.)	NA	--	NA	--
Thermo Fisher Sci.	A3	7.0	A-	7.0
UniFirst Corp.	NA	--	NA	--
UnitedHealth Group	A2	6.0	A+	5.0
Universal Corp.	WR	--	BBB-	10.0
VeriSign Inc.	Baa3	10.0	BBB	9.0
Waters Corp.	NA	--	NA	--
Watsco, Inc.	NA	--	NA	--
Natural Gas CEM Proxy Group Average	A3/Baa1	7.5	BBB+	7.8

Notes:
(1) From page 4 of Schedule DWD-4.

Source of Information:
Bloomberg Professional Services.

Valley Energy, Inc. / Citizens' Electric Company of Lewisburg, PA / Wellsboro Electric Company
Comparison of Long-Term Issuer Ratings for the
Proxy Group of Forty-Nine Non-Price Regulated Companies and Proxy Group of Forty-Seven Non-Price Regulated Companies

Proxy Group of Forty-Seven Non-Price Regulated Companies	Moody's Long-Term Issuer Rating February 2025		Standard & Poor's Long-Term Issuer Rating February 2025	
	Long-Term Issuer Rating	Numerical Weighting (1)	Long-Term Issuer Rating	Numerical Weighting (1)
3M Company	A3	7.0	BBB+	8.0
Abbott Laboratories	Aa3	4.0	AA-	4.0
Agilent Technologies, Inc.	Baa1	8.0	BBB+	8.0
Air Products and Chemicals, Inc.	A2	6.0	A	6.0
Allstate Corporation	A3	7.0	BBB+	8.0
Altria Group, Inc.	A3	7.0	BBB	9.0
Analog Devices, Inc.	A2	6.0	A-	7.0
Archer-Daniels-Midland Company	A2	6.0	A	6.0
Assurant, Inc.	Baa2	9.0	BBB	9.0
Brady Corporation	NA	--	NA	--
Broadridge Financial Solutions, Inc.	Baa2	9.0	BBB	9.0
Brown & Brown, Inc.	Baa3	10.0	BBB-	10.0
Brown-Forman Corporation 'B'	A1	5.0	A-	7.0
CACI International Inc	NA	--	BB+	11.0
Cisco Systems, Inc.	A1	5.0	AA-	4.0
Danaher Corporation	A3	7.0	A-	7.0
Dolby Laboratories, Inc.	NA	--	NA	--
Expeditors International	NA	--	NA	--
FactSet Research Systems Inc.	Baa3	10.0	NA	--
Fastenal Company	NA	--	NA	--
Federal Signal Corporation	NA	--	NA	--
Franklin Electric Co., Inc.	NA	--	NA	--
GATX Corporation	Baa2	9.0	BBB	9.0
Gentex Corporation	NA	--	NA	--
Home Depot, Inc.	A2	6.0	A	6.0
Ingredion, Inc.	Baa1	8.0	BBB	9.0
Innospec Inc.	NA	--	NR	--
International Business Machines Corporation	A3	7.0	A-	7.0
Juniper Networks, Inc.	Baa2	9.0	BBB	9.0
Lockheed Martin Corporation	A2	6.0	A-	7.0
Microsoft Corporation	Aaa	1.0	AAA	1.0
Motorola Solutions, Inc.	Baa2	9.0	BBB	9.0
MSA Safety, Inc.	NA	--	NA	--
MSC Industrial Direct Co., Inc.	NA	--	NA	--
O'Reilly Automotive, Inc.	Baa1	8.0	BBB	9.0
Packaging Corporation of America	Baa2	9.0	BBB	9.0
Philip Morris International Inc.	A2	6.0	A-	7.0
Selective Insurance Group, Inc.	Baa2	9.0	BBB	9.0
Sensient Technologies Corporation	WR	--	NR	--
Sherwin-Williams Company	Baa2	9.0	BBB	9.0
Smith Corporation (A.O.)	NA	--	NA	--
Texas Instruments Incorporated	Aa3	4.0	A+	5.0
Thermo Fisher Scientific Inc.	A3	7.0	A-	7.0
UniFirst Corporation	NA	--	NA	--
VeriSign, Inc.	Baa3	10.0	BBB	9.0
Verisk Analytics, Inc.	Baa1	8.0	BBB	9.0
Zoetis, Inc.	A3	7.0	BBB	9.0
Electric CEM Proxy Group Average	A3	7.2	BBB+	7.6

Notes:
(1) From page 4 of Schedule DWD-4.

Source of Information:
Bloomberg Professional Services.

Valley Energy, Inc. / Citizens' Electric Company of Lewisburg, PA / Wellsboro Electric Company
Derivation of Equity Risk Premium Based on the Total Market Approach
Using the Beta for
Non-Price Regulated Companies of Comparable risk to the
Proxy Group of Seven Natural Gas Distribution Companies and Proxy Group of Fifteen Electric Companies

Line No.	Equity Risk Premium Measure	Proxy Group of Forty-Nine Non-Price Regulated Companies	Proxy Group of Forty-Seven Non-Price Regulated Companies
1.	Kroll Equity Risk Premium (1)	6.10 %	6.10 %
2.	Regression on Kroll Risk Premium Data (2)	6.82	6.82
3.	Kroll Equity Risk Premium based on PRPM (3)	7.32	7.32
4.	Equity Risk Premium Based on Value Line Summary and Index (4)	5.85	5.85
5.	Equity Risk Premium Based on Bloomberg, Value Line, and S&P Global Market Intelligence S&P 500 Companies (5)	9.88	9.88
6.	Conclusion of Equity Risk Premium	7.19 %	7.19 %
7.	Adjusted Beta (6)	0.87	0.88
8.	Forecasted Equity Risk Premium	6.26 %	6.33 %

Notes:
(1) From note 1 of page 6 of Schedule DWD-4.
(2) From note 2 of page 6 of Schedule DWD-4.
(3) From note 3 of page 6 of Schedule DWD-4.
(4) From note 4 of page 6 of Schedule DWD-4.
(5) From note 5 of page 6 of Schedule DWD-4.
(6) Average of mean and median beta from pages 8-9 of this Schedule.

Sources of Information:
Kroll Cost of Capital Navigator
Value Line Summary and Index.
Blue Chip Financial Forecasts, November 27, 2024 and February 28, 2025
Bloomberg Professional Services.

Valley Energy, Inc. / Citizens' Electric Company of Lewisburg, PA / Wellsboro Electric Company
Traditional CAPM and ECAPM Results for the Proxy Groups of Non-Price-Regulated Companies Comparable in Total Risk to the
Proxy Group of Seven Natural Gas Distribution Companies and Proxy Group of Fifteen Electric Companies

Proxy Group of Forty-Nine Non-Price Regulated Companies

	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]
Proxy Group of Forty-Nine Non-Price Regulated Companies	Value Line Adjusted Beta	Bloomberg Beta	Average Beta	Market Risk Premium (1)	Risk-Free Rate (2)	Traditional CAPM Cost	ECAPM Cost Rate	Indicated Common Equity Cost Rate (3)
Abbott Labs.	0.85	0.62	0.73	8.15 %	4.55 %	10.50 %	11.05 %	10.78 %
AbbVie Inc.	0.80	0.49	0.65	8.15	4.55	9.85	10.56	10.21
Air Products & Chem.	0.90	0.89	0.89	8.15	4.55	11.80	12.03	11.92
Alphabet Inc.	0.90	0.98	0.94	8.15	4.55	12.21	12.33	12.27
Altria Group	0.85	0.46	0.66	8.15	4.55	9.93	10.62	10.28
Apple Inc.	0.95	0.93	0.94	8.15	4.55	12.21	12.33	12.27
Assurant Inc.	0.90	0.79	0.84	8.15	4.55	11.40	11.72	11.56
AutoZone Inc.	0.90	0.69	0.80	8.15	4.55	11.07	11.48	11.27
Booz Allen Hamilton	0.90	0.97	0.94	8.15	4.55	12.21	12.33	12.27
Brady Corp.	0.95	0.72	0.83	8.15	4.55	11.32	11.66	11.49
BWX Technologies	0.85	0.87	0.86	8.15	4.55	11.56	11.85	11.70
CACI Int'l	0.90	0.82	0.86	8.15	4.55	11.56	11.85	11.70
Casey's Gen'l Stores	0.90	0.66	0.78	8.15	4.55	10.91	11.36	11.13
Cencora	0.75	0.56	0.65	8.15	4.55	9.85	10.56	10.21
CSW Industrials	0.90	1.26	1.08	8.15	4.55	13.35	13.19	13.27
CVS Health	0.90	0.76	0.83	8.15	4.55	11.32	11.66	11.49
Danaher Corp.	0.90	0.90	0.90	8.15	4.55	11.89	12.09	11.99
Dolby Labs.	0.95	0.89	0.92	8.15	4.55	12.05	12.21	12.13
Exponent, Inc.	1.00	1.14	1.07	8.15	4.55	13.27	13.13	13.20
Fastenal Co.	0.85	0.93	0.89	8.15	4.55	11.80	12.03	11.92
Franklin Electric	0.90	1.01	0.96	8.15	4.55	12.38	12.46	12.42
GATX Corp.	0.95	1.04	1.00	8.15	4.55	12.70	12.70	12.70
Henry (Jack) & Assoc	0.85	0.69	0.77	8.15	4.55	10.83	11.30	11.06
Hunt (J.B.)	0.95	1.07	1.01	8.15	4.55	12.78	12.76	12.77
Huntington Ingalls	0.95	1.04	1.00	8.15	4.55	12.70	12.70	12.70
L3Harris Technologie	0.90	0.85	0.88	8.15	4.55	11.72	11.97	11.85
Landstar System	0.80	0.99	0.90	8.15	4.55	11.89	12.09	11.99
Lockheed Martin	0.85	0.47	0.66	8.15	4.55	9.93	10.62	10.28
McKesson Corp.	0.80	0.66	0.73	8.15	4.55	10.50	11.05	10.78
Microsoft Corp.	0.90	1.03	0.97	8.15	4.55	12.46	12.52	12.49
MSC Industrial Direc	0.90	0.88	0.89	8.15	4.55	11.80	12.03	11.92
Oracle Corp.	0.85	1.36	1.11	8.15	4.55	13.60	13.37	13.49
O'Reilly Automotive	0.90	0.59	0.75	8.15	4.55	10.66	11.17	10.92
OSI Systems	0.95	1.25	1.10	8.15	4.55	13.52	13.31	13.41
Packaging Corp.	0.95	0.79	0.87	8.15	4.55	11.64	11.91	11.77
Pfizer, Inc.	0.80	0.47	0.64	8.15	4.55	9.77	10.50	10.13
Philip Morris Int'l	0.90	0.45	0.67	8.15	4.55	10.01	10.68	10.35
Prestige Consumer	0.90	0.67	0.78	8.15	4.55	10.91	11.36	11.13
Selective Ins. Group	0.90	0.66	0.78	8.15	4.55	10.91	11.36	11.13
Service Corp. Int'l	0.95	0.90	0.92	8.15	4.55	12.05	12.21	12.13
Sherwin-Williams	0.95	1.16	1.05	8.15	4.55	13.11	13.01	13.06
Smith (A.O.)	0.90	0.96	0.93	8.15	4.55	12.13	12.27	12.20
Thermo Fisher Sci.	0.85	0.83	0.84	8.15	4.55	11.40	11.72	11.56
UniFirst Corp.	0.90	0.62	0.76	8.15	4.55	10.75	11.23	10.99
UnitedHealth Group	0.95	0.36	0.65	8.15	4.55	9.85	10.56	10.21
Universal Corp.	0.85	0.68	0.77	8.15	4.55	10.83	11.30	11.06
VeriSign Inc.	0.90	0.67	0.78	8.15	4.55	10.91	11.36	11.13
Waters Corp.	0.90	0.94	0.92	8.15	4.55	12.05	12.21	12.13
Watsco, Inc.	0.90	1.34	1.12	8.15	4.55	13.68	13.44	13.56
		Mean	0.86			11.58 %	11.86 %	11.72 %
		Median	0.87			11.64 %	11.91 %	11.77 %
		Average of Mean and Median	0.87			11.61 %	11.89 %	11.75 %

Notes on page 9 of this Schedule

Valley Energy, Inc. / Citizens' Electric Company of Lewisburg, PA / Wellsboro Electric Company
Traditional CAPM and ECAPM Results for the Proxy Groups of Non-Price-Regulated Companies Comparable in Total Risk to the
Proxy Group of Seven Natural Gas Distribution Companies and Proxy Group of Fifteen Electric Companies

Proxy Group of Forty-Seven Non-Price Regulated Companies

	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]
Proxy Group of Forty-Seven Non-Price Regulated Companies	Value Line Adjusted Beta	Bloomberg Beta	Average Beta	Market Risk Premium (1)	Risk-Free Rate (2)	Traditional CAPM Cost Rate	ECAPM Cost Rate	Indicated Common Equity Cost Rate (3)
3M Company	NMF	0.95	0.95	8.15 %	4.55 %	12.29 %	12.40 %	12.34 %
Abbott Laboratories	0.85	0.62	0.73	8.15	4.55	10.50	11.05	10.78
Agilent Technologies, Inc.	0.90	1.02	0.96	8.15	4.55	12.38	12.46	12.42
Air Products and Chemicals, Inc.	0.90	0.89	0.89	8.15	4.55	11.80	12.03	11.92
Allstate Corporation	1.00	0.63	0.81	8.15	4.55	11.15	11.54	11.35
Altria Group, Inc.	0.85	0.46	0.66	8.15	4.55	9.93	10.62	10.28 (4)
Analog Devices, Inc.	1.00	1.19	1.09	8.15	4.55	13.44	13.25	13.34
Archer-Daniels-Midland Company	0.95	0.59	0.77	8.15	4.55	10.83	11.30	11.06
Assurant, Inc.	0.90	0.79	0.84	8.15	4.55	11.40	11.72	11.56
Brady Corporation	0.95	0.72	0.83	8.15	4.55	11.32	11.66	11.49
Broadridge Financial Solutions, Inc.	0.90	0.86	0.88	8.15	4.55	11.72	11.97	11.85
Brown & Brown, Inc.	1.00	0.72	0.86	8.15	4.55	11.56	11.85	11.70
Brown-Forman Corporation 'B'	0.90	0.82	0.86	8.15	4.55	11.56	11.85	11.70
CACI International Inc	0.90	0.82	0.86	8.15	4.55	11.56	11.85	11.70
Cisco Systems, Inc.	0.85	0.81	0.83	8.15	4.55	11.32	11.66	11.49
Danaher Corporation	0.90	0.90	0.90	8.15	4.55	11.89	12.09	11.99
Dolby Laboratories, Inc.	0.95	0.89	0.92	8.15	4.55	12.05	12.21	12.13
Expeditors International	0.90	0.77	0.84	8.15	4.55	11.40	11.72	11.56
FactSet Research Systems Inc.	1.00	0.84	0.92	8.15	4.55	12.05	12.21	12.13
Fastenal Company	0.85	0.93	0.89	8.15	4.55	11.80	12.03	11.92
Federal Signal Corporation	1.00	1.25	1.13	8.15	4.55	13.76	13.50	13.63 (4)
Franklin Electric Co., Inc.	0.90	1.01	0.96	8.15	4.55	12.38	12.46	12.42
GATX Corporation	0.95	1.04	1.00	8.15	4.55	12.70	12.70	12.70
Gentex Corporation	1.00	0.95	0.98	8.15	4.55	12.54	12.58	12.56
Home Depot, Inc.	0.95	1.08	1.01	8.15	4.55	12.78	12.76	12.77
Ingredion, Inc.	0.90	0.71	0.80	8.15	4.55	11.07	11.48	11.27
Innospec Inc.	0.95	1.15	1.05	8.15	4.55	13.11	13.01	13.06
International Business Machines Corporation	0.95	0.77	0.86	8.15	4.55	11.56	11.85	11.70
Juniper Networks, Inc.	0.95	0.62	0.79	8.15	4.55	10.99	11.42	11.20
Lockheed Martin Corporation	0.85	0.47	0.66	8.15	4.55	9.93	10.62	10.28 (4)
Microsoft Corporation	0.90	1.03	0.97	8.15	4.55	12.46	12.52	12.49
Motorola Solutions, Inc.	0.95	0.94	0.94	8.15	4.55	12.21	12.33	12.27
MSA Safety, Inc.	1.00	0.90	0.95	8.15	4.55	12.29	12.40	12.34
MSC Industrial Direct Co., Inc.	0.90	0.88	0.89	8.15	4.55	11.80	12.03	11.92
O'Reilly Automotive, Inc.	0.90	0.59	0.75	8.15	4.55	10.66	11.17	10.92
Packaging Corporation of America	0.95	0.79	0.87	8.15	4.55	11.64	11.91	11.77
Philip Morris International Inc.	0.90	0.45	0.67	8.15	4.55	10.01	10.68	10.35
Selective Insurance Group, Inc.	0.90	0.66	0.78	8.15	4.55	10.91	11.36	11.13
Sensient Technologies Corporation	0.95	0.97	0.96	8.15	4.55	12.38	12.46	12.42
Sherwin-Williams Company	0.95	1.16	1.05	8.15	4.55	13.11	13.01	13.06
Smith Corporation (A.O.)	0.90	0.96	0.93	8.15	4.55	12.13	12.27	12.20
Texas Instruments Incorporated	0.90	1.09	0.99	8.15	4.55	12.62	12.64	12.63
Thermo Fisher Scientific Inc.	0.85	0.83	0.84	8.15	4.55	11.40	11.72	11.56
UniFirst Corporation	0.90	0.62	0.76	8.15	4.55	10.75	11.23	10.99
VeriSign, Inc.	0.90	0.67	0.78	8.15	4.55	10.91	11.36	11.13
Verisk Analytics, Inc.	0.90	0.72	0.81	8.15	4.55	11.15	11.54	11.35
Zoetis, Inc.	1.00	0.86	0.93	8.15	4.55	12.13	12.27	12.20
		Mean	0.88			11.73 %	11.97 %	11.88 %
		Median	0.88			11.72 %	11.97 %	11.89 %
		Average of Mean and Median	0.88			11.73 %	11.97 %	11.89 %

Notes:
(1) From note 1 of page 2 of Schedule DWD-5.
(2) From note 2 of page 2 of Schedule DWD-5.
(3) Average of CAPM and ECAPM cost rates.
(4) Results were excluded from the final average and median as they were more than two standard deviations from the proxy group's mean.

Valley Energy, Inc. / Citizens' Electric Company of Lewisburg, PA / Wellsboro Electric Company
Derivation of Investment Risk Adjustment Based upon
Ibbotson Associates' Size Premia for the Decile Portfolios of the NYSE/AMEX/NASDAQ

Line No.		[1] Market Capitalization on February 28, 2025 (1) (millions)	(times larger)		[2] Applicable Decile of the NYSE/AMEX/ NASDAQ (2)	[3] Applicable Size Premium (3)	[4] Spread from Applicable Size Premium (4)
1.	a. Valley Energy, Inc.	$ 18.603			10	4.47%	
	b. Citizens' Electric Company of Lewisburg, PA	$ 18.097			10	4.47%	
	c. Wellsboro Electric Company	$ 24.787			10	4.47%	
2.	a. Proxy Group of Seven Natural Gas Distribution Companies	$ 4,721.136	253.8	x	5	0.74%	3.73%
	b. Proxy Group of Fifteen Electric Companies	$ 16,525.930	913.2	x	3	0.49%	3.98%
	c. Proxy Group of Fifteen Electric Companies	$ 16,525.930	666.7	x	3	0.49%	3.98%
			[A]		[B]	[C]	[D]

	Decile	Market Capitalization of Smallest Company (millions)	Market Capitalization of Largest Company (millions)	Size Premium (Return in Excess of CAPM)*
Largest	1	$ 47,156.530	$ 3,522,211.140	-0.01%
	2	20,191.220	46,949.060	0.33%
	3	9,937.940	20,178.360	0.49%
	4	6,196.710	9,937.350	0.50%
	5	3,948.050	6,181.270	0.74%
	6	2,481.780	3,946.150	1.00%
	7	1,422.890	2,464.500	1.19%
	8	731.190	1,417.450	0.88%
	9	304.620	729.920	1.73%
Smallest	10	1.110	304.480	4.47%

*From 2025 Kroll Cost of Capital Navigator

Notes:

(1) From page 2 of this Schedule.
(2) Gleaned from Columns [B] and [C] on the bottom of this page. The appropriate decile (Column [A]) corresponds to the market capitalization of the proxy group, which is found in Column [1].
(3) Corresponding risk premium to the decile is provided in Column [D] on the bottom of this page.
(4) Line No. 1 Column [3] – Line No. 2 Column [3]. For example, the 3.73% in Column [4], Line No. 2 is derived as follows 3.73% = 4.47% - 0.74%.

Valley Energy, Inc. / Citizens' Electric Company of Lewisburg, PA / Wellsboro Electric Company
Market Capitalization of Valley Energy, Inc. / Citizens' Electric Company of Lewisburg, PA / Wellsboro Electric Company and the
Proxy Group of Seven Natural Gas Distribution Companies and Proxy Group of Fifteen Electric Companies

		[1]	[2]	[3]	[4]	[5]	[6]
Company	Exchange	Common Stock Shares Outstanding at Fiscal Year End 2024 (millions)	Book Value per Share at Fiscal Year End 2023 (1)	Total Common Equity at Fiscal Year End 2024 (millions)	Closing Stock Market Price on February 28, 2025	Market-to-Book Ratio on February 28, 2025 (2)	Market Capitalization on February 28, 2025 (3) (millions)
Valley Energy, Inc.		NA	NA	$ 11.462 (4)	NA		
Citizens' Electric Company of Lewisburg, PA		NA	NA	$ 9.022 (4)	NA		
Wellsboro Electric Company		NA	NA	$ 12.356 (4)	NA		
Based upon Proxy Group of Seven Natural Gas Distribution Companies						162.3 (5)	$ 18.603 (6)
Based upon Proxy Group of Fifteen Electric Companies						200.6 (5)	$ 18.097 (6)
Based upon Proxy Group of Fifteen Electric Companies						200.6 (5)	$ 24.787 (6)
Proxy Group of Seven Natural Gas Distribution Companies							
Atmos Energy Corporation	NYSE	148.49	$ 73.203	$ 10,870.06	$ 152.13	207.8 %	$ 22,590.207
New Jersey Resources Corporation	NYSE	97.58	20.40	1,990.74	48.38	237.20	4,721.14
NiSource Inc.	NYSE	447.38	17.40	7,783.50	40.81	234.60	18,257.65
Northwest Natural Holding Company	NYSE	37.63	34.12	1,283.84	40.88	119.80	1,538.36
ONE Gas, Inc.	NYSE	56.55	48.91	2,765.88	75.15	153.60	4,249.43
Southwest Gas Holdings, Inc.	NYSE	71.56	46.25	3,310.04	75.05	162.30	5,370.86
Spire Inc.	NYSE	53.17	54.87	2,917.30	76.86	140.10	4,086.66
Median		71.564	$ 46.253	$ 2,917.300	$ 75.050	162.3 %	$ 4,721.136
Proxy Group of Fifteen Electric Companies							
Alliant Energy Corporation	NASDAQ	256.10	$ 26.463	$ 6,777.00	$ 64.53	243.8 %	$ 16,525.930
Ameren Corporation	NYSE	266.30	42.62	11,349.00	101.56	238.30	27,045.43
American Electric Power Corporation	NASDAQ	526.18	47.98	25,246.70	106.05	221.00	55,801.88
Duke Energy Corporation	NYSE	771.00	61.15	47,150.00	117.49	192.10	90,584.79
Edison International	NYSE	383.92	36.02	13,828.00	54.44	151.20	20,900.87
Entergy Corporation	NYSE	212.85	68.70	14,622.65	87.31	127.10	18,583.81
Evergy, Inc.	NASDAQ	229.73	42.06	9,663.10	68.91	163.80	15,830.65
IDACORP, Inc.	NYSE	50.62	57.45	2,907.57	117.91	205.30	5,968.04
North Western Corporation	NASDAQ	64.76	43.01	2,785.31	55.93	130.00	3,622.13
OGE Energy Corporation	NYSE	200.30	22.52	4,511.60	46.28	205.50	9,269.88
Pinnacle West Capital Corporation	NYSE	113.54	54.41	6,177.66	92.54	170.10	10,506.78
Portland General Electric Company	NYSE	101.16	32.81	3,319.00	44.83	136.60	4,534.99
Southern Company	NYSE	1,092.00	28.80	31,444.00	89.79	311.80	98,050.68
TXNM Energy, Inc.	NYSE	90.20	26.04	2,349.09	52.25	200.60	4,712.97
Xcel Energy Inc.	NASDAQ	554.94	31.75	17,617.00	72.10	227.10	40,011.30
Median		229.729	$ 42.063	$ 9,663.100	$ 72.100	200.6 %	$ 16,525.930

NA= Not Available

Notes: (1) Column 3 / Column 1.
(2) Column 4 / Column 2.
(3) Column 1 * Column 4.
(4) Requested rate base multiplied by the requested common equity ratio.
(5) The market-to-book ratio of Valley Energy, Inc. / Citizens' Electric Company of Lewisburg, PA / Wellsboro Electric Company on February 28, 2025 is assumed to be equal to the market-to-book ratio of Proxy Group of Seven Natural Gas Distribution Companies and Proxy Group of
(6) Column [3] multiplied by Column [5].

Source of Information: 2024 Annual Forms 10K
Bloomberg Professional

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	**:**		
	:		
v.	**:**	**Docket Nos.**	**R-2025-3054392**
	:		**R-2025-3054393**
Citizens' Electric Company of Lewisburg, PA,	**:**		**R-2025-3054394**
Valley Energy Company, and Wellsboro	**:**		
Electric Company	**:**		

REBUTTAL TESTIMONY

AND EXHIBIT

OF

DYLAN W. D'ASCENDIS

ON BEHALF OF

CITIZENS' ELECTRIC COMPANY OF LEWISBURG, PA,
VALLEY ENERGY, INC., AND
WELLSBORO ELECTRIC COMPANY

AUGUST 13, 2025

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I. INTRODUCTION, PURPOSE AND SUMMARY

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Dylan W. D'Ascendis. My business address is 1820 Chapel Ave., W., Suite 300, Cherry Hill, N.J. 08003.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am a Partner at ScottMadden, Inc.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING?

A. I am submitting this rebuttal testimony (referred to throughout as my "Rebuttal Testimony") before the Pennsylvania Public Utility Commission ("PA PUC" or the "Commission") on behalf of Valley Energy, Inc. ("Valley"), Citizens' Electric Company of Lewisburg, PA ("Citizens'"), and Wellsboro Electric Company ("Wellsboro") (collectively "the Companies").

Q. ARE YOU THE SAME DYLAN W. D'ASCENDIS WHO PROVIDED DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes, I am.

Q. WHAT IS THE PURPOSE OF THIS REBUTTAL TESTIMONY?

A. The purpose of my Rebuttal Testimony is two-fold. First, I update the analyses in my Direct Testimony to reflect current data. Second, I address certain aspects of the direct testimonies of Mr. Christopher Keller and Mr. D. C. Patel, witnesses for the PA PUC's Bureau of Investigation and Enforcement ("I&E") (collectively, the "I&E ROE Witnesses"), Mr. Christopher C. Walters, witness for the Pennsylvania Office of Consumer Advocate ("OCA"), and Mr. Justin B. Farr, witness for the Pennsylvania Office of Small Business Advocate ("OSBA") (collectively referred to as the "Opposing Witnesses") as they pertain to the Companies' allowed cost of capital, which the Companies should have the opportunity to earn on their authorized jurisdictional rate base.

Q. PLEASE SUMMARIZE THE KEY ISSUES AND RECOMMENDATIONS OFFERED BY THE OPPOSING WITNESSES THAT YOU ADDRESS IN YOUR REBUTTAL TESTIMONY.

A. Due to the passage of time since my Direct Testimony analysis (which included data as of February 28, 2025), I have updated my analysis using data as of July 18, 2025. Based on these updated analyses, the reasonable range of ROEs attributable to Valley are from 10.42% to 10.89% (unadjusted) and from 11.47% to 11.94% (adjusted) and the reasonable range of ROEs attributable to Citizens' and Wellsboro are from 10.19% to 10.76% (unadjusted) and from 11.09% to 11.66% (adjusted). Given these ranges, my recommended ROEs for the Companies of 11.65% continues to be reasonable. Conversely, recommended ROEs of 10.51% (Mr. Patel for Valley), 10.78% (Mr. Keller for Citizens' and Wellsboro), and 9.50% (Mr. Walters for all Companies) are inadequate at this time.[1]

My Rebuttal Testimony also responds to substantive recommendations offered by the Opposing Witnesses in their direct testimonies. Regarding the I&E ROE Witnesses' direct testimonies, their ROE recommendations generally fall within my initial and updated model results before adjustments for Company-specific factors. I will address why the Companies' small size and management performance adjustments should continue to be considered by the Commission when determining their ROEs. Adjusting the I&E ROE Witnesses' recommended ROEs for Company-specific factors would result in ROEs similar to my recommendation.

Regarding Mr. Walters' direct testimony, I will discuss my disagreement with several inputs Mr. Walters uses in his analysis that serve to understate his recommended

[1] Mr. Farr does not conduct an independent analysis of the Companies' ROE, but relies on the Commission's Bureau of Technical Utility Services ("TUS") quarterly calculation of the ROE for the Distribution System Improvement Charge ("DSIC") for his recommendation.

ROE. For example, I disagree with Mr. Walters' use of the sustainable growth version of the Discounted Cash Flow ("DCF") model, his use of the multi-stage DCF model ("MSDCF") and his application of the Capital Asset Pricing Model ("CAPM").

Regarding Mr. Farr's direct testimony, while he does not conduct an independent assessment of the Companies' appropriate ROEs, he relies on the Bureau of Technical Utility Services' ("TUS") quarterly calculation of the ROE for the Distribution System Improvement Charge ("DSIC"). Like the I&E ROE Witnesses' analysis, the range of ROEs calculated by the TUS in their quarterly report are comparable to my initial and updated model results and the top end of the ROE ranges for gas and electric utilities are comparable to my Company-specific recommendation. The calculated ranges of ROEs, however, do not reflect the Companies' managements' performance, and therefore is an incomplete analysis of the Companies' ROE.

My Rebuttal Testimony discusses these factors and others in detail. My Rebuttal Testimony also addresses the unfounded critiques of my Direct Testimony.

Q. HAVE YOU PREPARED AN EXHIBIT WHICH SUPPORTS YOUR REBUTTAL TESTIMONY?

A. Yes. It has been designated as Exhibit__(DWD-1R), which consists of Schedules DWD-1R through DWD-14R.

Q. HOW IS THE REMAINDER OF YOUR REBUTTAL TESTIMONY ORGANIZED?

A. The remainder of my Rebuttal Testimony is organized as follows:

- Section II – Presents my updated analysis;
- Section III – Contains my response to the I&E ROE Witnesses;
- Section IV – Contains my response to Mr. Walters; and

- Section V – Contains my response to Mr. Farr;
- Section VI – Summarizes my conclusions and recommendations.

II. UPDATED ANALYSIS

Q. HAVE YOU UPDATED YOUR COST OF COMMON EQUITY ANALYSES?

A. Yes, I have. Due to the passage of time since my Direct Testimony analysis (which included data as of February 28, 2025), I have updated my analysis using data as of July 18, 2025.

Q. HAVE YOU APPLIED ANY OF YOUR ROE MODELS DIFFERENTLY IN YOUR UPDATED ANALYSES?

A. No, I have not.

Q. HAVE YOU UPDATED YOUR UTILITY PROXY GROUPS IN YOUR UPDATED ANALYSES?

A. Yes, I have. I re-ran my selection criteria put forth in my Direct Testimony[2] and used 2024 fiscal year data to select updated proxy groups as shown on Tables 1 and 2 below:

Table 1: Updated Gas Proxy Group[3]

Company	Ticker
Atmos Energy Corporation	ATO
Chesapeake Utilities Corporation	CPK
New Jersey Resources Corporation	NJR
NiSource, Inc.	NI
Northwest Natural Holding Company	NWN
ONE Gas, Inc.	OGS
Southwest Gas Holdings, Inc.	SWX
Spire Inc.	SR

[2] D'Ascendis Direct Testimony, at 14-15.

[3] Chesapeake Utilities Corporation passed all selection criteria using fiscal year 2024 data.

Table 2: Updated Electric Proxy Group[4]

Company	Ticker
Alliant Energy Corporation	LNT
American Electric Power Corporation	AEP
Ameren Corporation	AEE
Duke Energy Corporation	DUK
Edison International	EIX
Entergy Corporation	ETR
Evergy, Inc.	EVRG
FirstEnergy Corporation	FE
IDACORP, Inc.	IDA
OGE Energy Corporation	OGE
Pinnacle West Capital Corporation	PNW
Portland General Electric Company	POR
Southern Company	SO
Xcel Energy, Inc.	XEL

Q. PLEASE SUMMARIZE YOUR UPDATED COST OF COMMON EQUITY RESULTS BASED ON YOUR UPDATED ANALYSES.

A. Using data as of July 18, 2025, my updated results are presented in page 2 of Schedule DWD-1R, and in Table 3, below.

[4] FirstEnergy's sale of transmission assets closed March of 2024 and now passes all other selection criteria. NorthWestern Corporation no longer passes the criterion that requires 70% or more assets attributable to regulated electric operations. TXNM Energy Inc. no longer passes criterion (iii) which prohibits inclusion of companies involved in any major merger or acquisition activity.

Table 3: Summary of Updated Common Equity Rates

	Gas Proxy Group	Electric Proxy Group
Discounted Cash Flow Model	10.42%	10.19%
Risk Premium Model	10.72%	10.70%
Capital Asset Pricing Model	10.82%	10.42%
Cost of Equity Models Applied to Comparable Risk, Non-Price Regulated Companies	10.89%	10.76%
Indicated Range of Common Equity Cost Rates Before Adjustments	10.42% - 10.89%	10.19% - 10.76%
Size Adjustment	1.00%	0.85%
Performance Factor Adjustment	0.05%	0.05%
Indicated Range of Common Equity Cost Rates After Adjustments	11.47% - 11.94%	11.09% - 11.66%
Recommended Cost of Common Equity After Adjustments	11.65%	11.65%

In view of the unadjusted and adjusted ranges of ROEs, I maintain my original recommendation of 11.65% for the Companies.

III. RESPONSE TO I&E ROE WITNESSES KELLER AND PATEL

Q. PLEASE SUMMARIZE MR. PATEL'S RECOMMENDATIONS REGARDING THE OVERALL COST OF CAPITAL FOR VALLEY.

A. Mr. Patel accepts Valley's requested capital structure and cost of long-term debt.[5] Regarding the appropriate ROE for Valley, Mr. Patel recommends a 10.51% ROE based on his DCF results.[6]

[5] Patel Direct Testimony, at 16-17.
[6] *Id.* at 30.

Q. PLEASE SUMMARIZE MR. KELLER'S RECOMMENDATIONS REGARDING THE OVERALL COST OF CAPITAL FOR CITIZENS' AND WELLSBORO.

A. Mr. Keller accepts Citizens' and Wellsboro's capital structure and long-term debt cost rate.[7] Regarding ROE, Mr. Keller recommends an ROE of 10.78%, based on his DCF model.[8]

Q. DO YOU HAVE ANY GENERAL COMMENTS ON THE I&E ROE WITNESSES' INDICATED MODEL RESULTS?

A. Yes, I do. While I do not agree generally with several inputs used by the I&E ROE Witnesses in their analyses, or their sole reliance on the DCF model, their ROE recommendations fall within my unadjusted range of ROE results. Because the U.S. Supreme Court stated that: "Under the statutory standard of 'just and reasonable' it is the result reached not the method employed which is controlling."[9], and both of our approaches indicate comparable results applicable to our respective proxy groups, I will not discuss my concerns with their approaches or the bases of their recommendations.

Q. THAT SAID, DO YOU HAVE ANY CONCERNS ABOUT THE I&E ROE WITNESSES' ULTIMATE ROE RECOMMENDATIONS?

A. Yes, I do. The I&E ROE Witnesses' recommendations do not reflect the Companies' smaller size compared to their own proxy groups or a performance factor adjustment. These omissions serve to understate the Companies' required return.

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7 Keller Direct Testimony, at 16-17.
8 *Id.* at 29.
9 *Fed. Power Comm'n v. Hope Nat. Gas Co*., 320 U.S. 591, 64 S. Ct. 281, 88 L. Ed. 333 (1944)

A. FAILURE TO REFLECT THE COMPANIES' GREATER RELATIVE RISK DUE TO THEIR SMALL SIZE

Q. DO THE I&E ROE WITNESSES MAKE A SPECIFIC ADJUSTMENT TO REFLECT THE SMALLER SIZE OF THE COMPANIES RELATIVE TO THEIR PROXY GROUPS?

A. No. As discussed in my Direct Testimony,[10] relative company size is a significant element of business risk for which investors expect to be compensated through greater returns. Smaller companies are simply less able to cope with significant events which affect sales, revenues and earnings. For example, smaller companies face more exposure to business cycles and economic conditions, both nationally and locally. Additionally, the loss of revenues from a few large customers would have a far greater effect on a small company than on a larger company with a more diverse customer base. Finally, smaller companies are generally less diverse in their operations and have less financial flexibility. Consistent with the financial principle of risk and return in my Direct Testimony,[11] such increased risk due to small size must be taken into account in the allowed rate of return on common equity.

Q. DO THE I&E ROE WITNESSES RELY ON STUDIES THAT SUPPORT THE SMALL SIZE PREMIUM?

A. Yes. In the Fama and French article cited by the I&E ROE Witnesses in their direct testimony,[12] the authors propose that their three-factor model include the "Small Minus Big" factor, which indicates that small capitalization firms are more risky than large

10 D'Ascendis Direct Testimony, at 47-51.
11 *Id.* at 47-49.
12 *See,* Keller Direct Testimony, at 44 and Patel Direct Testimony, at 48.

capitalization firms,[13] confirming that size is a risk factor which must be taken into account in estimating the cost of common equity.

Q. THE I&E ROE WITNESSES CITE A STUDY BY DR. ANNIE WONG FOR THE PROPOSITION THAT THERE IS NO SIZE PREMIUM FOR UTILITIES.[14] DOES THIS STUDY ESTABLISH THAT CONTENTION?

A. No, it does not. In the Wong study, Dr. Wong attempted to relate a change in beta to the size effect. Dr. Wong's beta study is incorrect, as beta is a measure of market risk, whereas size is a company-specific, or diversifiable risk. While betas may contain some measure of diversifiable risk, betas have low explanatory power. As shown in Schedule DWD-2R, the R-Squared, which measures the variability of returns applicable to beta, is approximately 0.19 for Mr. Patel's gas proxy group and 0.20 for Mr. Keller's electric proxy group, which means approximately 79% to 80% of the I&E ROE Witnesses' proxy group's returns are unexplained by beta.

Q. IS THERE ALSO A PUBLISHED RESPONSE TO DR. WONG'S ARTICLE?

A. Yes, there is. In response to Professor Wong's article, *The Quarterly Review of Economics and Finance* published an article in 2003, authored by Thomas M. Zepp, which commented on the Wong article cited by Mr. Keller. Relative to Dr. Wong's results, Dr. Zepp concluded in the Abstract on page 1 of his article: "Her weak results, however, do not rule out the possibility of a small firm effect for utilities."[15] Dr. Zepp also noted on page 582 that: "Two other studies discussed here support a conclusion that smaller water utility

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13 Eugene F. Fama and Kenneth R. French, "The Capital Asset Pricing Model: Theory and Evidence", *Journal of Economic Perspectives*, Vol. 18, No. 3, Summer 2004, at 39.

14 Keller Direct Testimony, at 45, and Patel Direct Testimony, at 51.

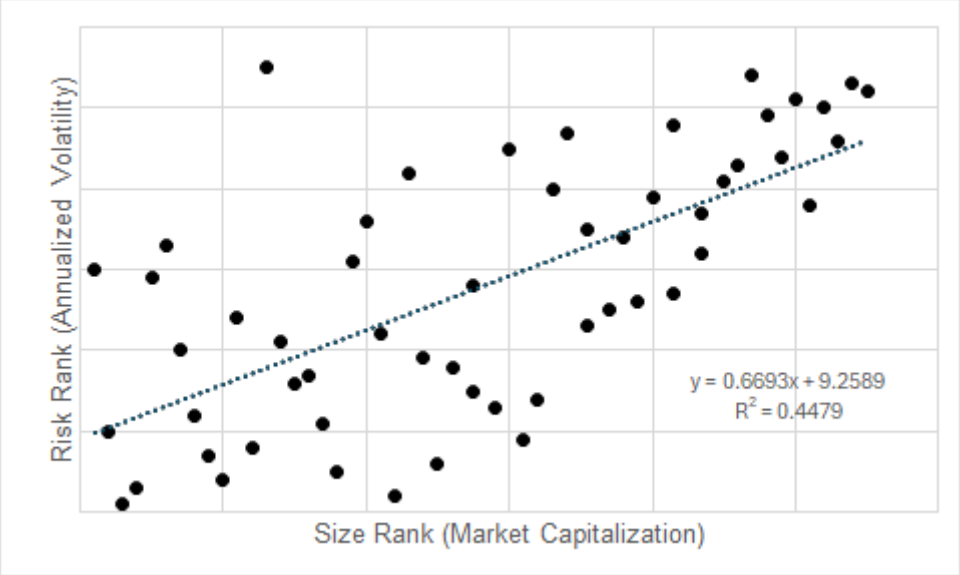
15 Thomas M. Zepp, "Utility Stocks and the Size Effect --- Revisited", *The Quarterly Review of Economics and Finance*, 43 (2003), at 578-582.

stocks are more risky than larger ones. To the extent that water utilities are representative of all utilities, there is support for smaller utilities being more risky than larger ones."[16]

Q. HAVE YOU PERFORMED STUDIES LINKING SIZE AND RISK FOR UTILITY COMPANIES?

A. Yes, I have performed two studies that link size and risk for utility companies. My first study included the universe of electric, gas, and water companies included in *Value Line* Standard Edition. For each of the utilities, the annualized volatility (a measure of risk)[17] was calculated, and each company was ranked by its current market capitalization (a measure of size) as reported by *Value Line*. Ranking the companies by size (largest to smallest) and risk (least risky to most risky), results in the scatterplot shown on Chart 1, below:

Chart 1: Relationship Between Size and Risk for the *Value Line* Universe of Utility Companies[18]



[16] Thomas M. Zepp, "Utility Stocks and the Size Effect --- Revisited", *The Quarterly Review of Economics and Finance*, 43 (2003), at 578-583.

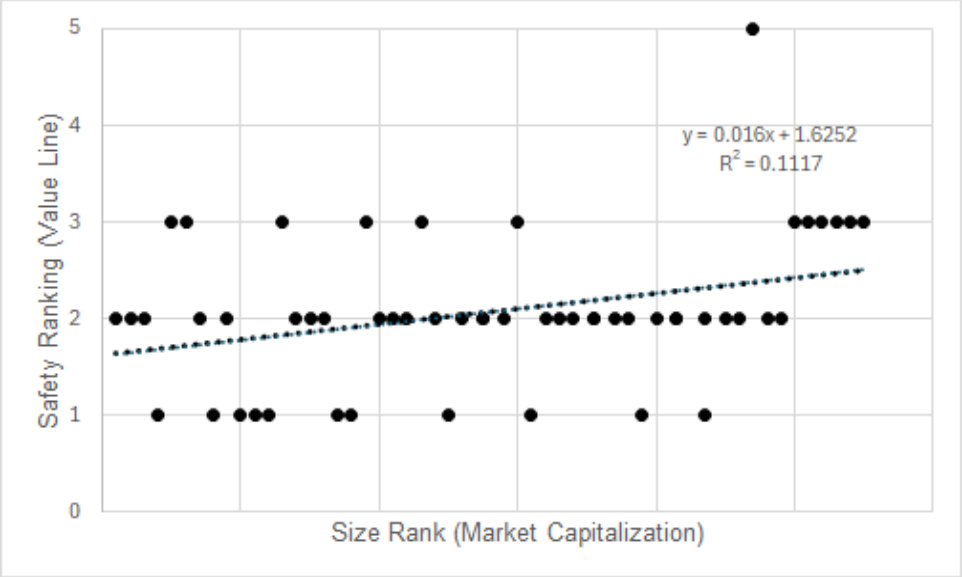
[17] Annualized volatility equals the standard deviation of returns over the period multiplied by the square root of 252, or the approximate number of trading days in a year.

[18] Source: *Value Line*

As shown in Chart 1 above, as company size decreases (increasing size rank), the annualized volatility increases, linking size and risk for utilities, which is significant at 95.0% confidence level.

The second study used the same universe of companies, but instead of annualized volatility, I used the *Value Line* Safety Ranking, which is another measure of total risk.[19] After ranking the companies by size and Safety Ranking, I made a scatterplot of those data, as shown on Chart 2, below:

Chart 2: Relationship Between Size and Safety Ranking for the *Value Line* Universe of Utility Companies[20]



Similar to the first study, as company size decreases, Safety Ranking degrades, indicating a link between size and risk for utilities. This study is also significant at the 95% confidence level. The I&E ROE Witnesses assertions that size and risk are not linked for utility companies should be dismissed by the Commission.

[19] *Value Line* also ranks stocks for Safety by analyzing the total risk of a stock compared to the approximately 1,700 stocks in the *Value Line* universe. Each of the stocks tracked in the *Value Line Investment Survey* is ranked in relationship to each other, from 1 (the highest rank) to 5 (the lowest rank). Safety is a quality rank, not a performance rank, and stocks ranked 1 and 2 are most suitable for conservative investors; those ranked 4 and 5 will be more volatile. Volatility means prices can move dramatically and often unpredictably, either down or up. The major influences on a stock's Safety rank are the company's financial strength, as measured by balance sheet and financial ratios, and the stability of its price over the past five years.

[20] Source: *Value Line*.

Q. THE I&E ROE WITNESSES POINT TO THE COMMISSION'S DECISION IN DOCKET NO. 2019-3008212 IN NOTING THAT THE COMMISSION DID NOT MAKE AN EXPLICIT SIZE ADJUSTMENT.[21] PLEASE COMMENT.

A. While the Commission did not make an explicit size adjustment in that proceeding, it did acknowledge that size is a factor in assessing a company's ability to attract capital (i.e., the cost required by investors).[22] Specifically, the Commission adjusted the DCF result by one standard deviation of the mean and median to account for size. Applying that same approach in my Direct Testimony resulted in size premiums of 1.53% for Valley and 0.85% for Citizens' and Wellsboro,[23] consistent with my recommended size premiums for Valley and Citizens' and Wellsboro, respectively.

Q. HAVE YOU CALCULATED THE STANDARD DEVIATION OF THE I&E ROE WITNESSES' DCF RESULTS?

A. Yes, I have. As put forth in Schedule DWD-3R, using data from the I&E ROE Witnesses' Exhibits, I have calculated an 81-basis-point standard deviation for Mr. Patel's DCF results and a 115-basis-point standard deviation for Mr. Keller's DCF results. These indicated size adjustments are comparable to my recommended size adjustments and should continue to be considered by the Commission when determining the appropriate ROEs for the Companies in this proceeding.

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21 *See,* Keller Direct Testimony, at 46, and Patel Direct Testimony, at 52.
22 D'Ascendis Direct Testimony, at 50-51.
23 *Id.* at 51.

B. PERFORMANCE FACTOR ADJUSTMENT

Q. THE OPPOSING WITNESSES HAVE NOT CONSIDERED A PERFORMANCE FACTOR ADJUSTMENT FOR THE COMPANIES' COST OF COMMON EQUITY. PLEASE COMMENT.

A. As discussed in my Direct Testimony,[24] the Companies should each be awarded a five-basis point upward adjustment to their indicated ROE based on Code 66 Pa.C.S. § 523 regarding performance factor. Mr. Rogers (Valley), Mr. Johnson (Citizens'), and Mr. Farnsworth (Wellsboro) testified[25] regarding the management efficiency of the Companies. No witness from I&E or the OCA has refuted the efficiency of each Company's management, yet both refuted the adjustment, since the Companies were simply doing "what they are required to do". Simply put, Code 66 Pa.C.S. § 523 is in existence to incentivize companies to "do their job" at a high level. The Companies in this case fulfill the requirement of the statute and should receive the benefit of doing so.

C. RESPONSE TO THE I&E ROE WITNESSES' CRITICISMS OF COMPANY TESTIMONY

Q. DO THE I&E ROE WITNESSES HAVE CRITIQUES OF THE ANALYSES MADE IN YOUR DIRECT TESTIMONY?

A. Yes. The I&E ROE Witnesses have the following critiques of my analyses in my Direct Testimony: (1) that I have given weight to models other than the DCF in my determination of the ROE for the Companies; (2) that the PRPM is relatively new and not commonly used and cannot be performed without expense; (3) my use of the Empirical CAPM ("ECAPM"); (4) that I rely on the 30-year Treasury bond in my CAPM analysis; (5) that

[24] D'Ascendis Direct Testimony, at 51-52.

[25] *See,* Rogers Rebuttal Testimony, at 3-4, Johnson Rebuttal Testimony, at 2-5, and Farnsworth Rebuttal Testimony, at 2-3.

the Market Risk Premium ("MRP") used in my CAPM is too high; (6) that my selection and use of a Non-Price Regulated Proxy Group similar in total risk to my Utility Proxy Group is "speculative and subjective";[26] (7) that the size adjustment I use is not applicable to utility companies; and (8) that exemplary management performance is not a basis for awarding a higher ROE.

As I addressed critiques (7) and (8) in my response to the I&E ROE Witnesses' analyses, I will not address them again here. I will address the remaining critiques in turn.

Q. DO YOU AGREE WITH THE I&E ROE WITNESSES THAT YOU PLACE TOO MUCH WEIGHT ON MODELS OTHER THAN THE DCF MODEL?

A. No, I do not. As discussed in my Direct Testimony,[27] the use of multiple models adds reliability to the estimation of the common equity cost rate, with the prudence of using multiple cost of common equity models supported in both the financial literature and regulatory precedent.

Q. DOES MR. WALTERS ECHO YOUR OPINION IN HIS DIRECT TESTIMONY?

A. Yes, he does. At page 27 of his direct testimony, Mr. Walters states that "Using multiple models provides a more comprehensive and balanced view, helps identify outlier results, and increases confidence that the final estimate reasonably reflects investor expectations under current market conditions."

Q. ARE THERE EXAMPLES FROM FINANCIAL LITERATURE WHICH SUPPORT THE USE OF MULTIPLE COST OF COMMON EQUITY MODELS IN DETERMINING THE INVESTOR-REQUIRED RETURN?

A. Yes. In one example, Morin states:

> Each methodology requires the exercise of considerable judgment on the reasonableness of the assumptions underlying the methodology and on the

[26] Keller Direct Testimony, at 42.
[27] D'Ascendis Direct Testimony, at 46.

reasonableness of the proxies used to validate a theory. The inability of the DCF model to account for changes in relative market valuation, discussed below, is a vivid example of the potential shortcomings of the DCF model when applied to a given company. Similarly, the inability of the CAPM to account for variables that affect security returns other than beta tarnishes its use.

No one individual method provides the necessary level of precision for determining a fair return, but each method provides useful evidence to facilitate the exercise of an informed judgment. Reliance on any single method or preset formula is inappropriate when dealing with investor expectations because of possible measurement difficulties and vagaries in individual companies' market data. (emphasis added)

* * *

There is ample academic support in the financial literature for the need to rely upon several financial models in arriving at a recommended common equity cost rate. Professor Eugene Brigham, a widely respected scholar and finance academician, asserts(footnote omitted):

> *Three methods typically are used: (1) the Capital Asset Pricing Model (CAPM), (2) the discounted cash flow (DCF) method, and (3) the bond-yield-plus-risk-premium approach.* ***These methods are not mutually exclusive – no method dominates the others****, and all are subject to error when used in practice. Therefore, when faced with the task of estimating a company's cost of equity, we generally use all three methods and then choose among them on the basis of our confidence in the data used for each in the specific case at hand. (italics in original) (emphasis added)*

Another prominent finance scholar, Professor Stewart Myers, in an early pioneering article on regulatory finance, stated(footnote omitted):

> *Use more than one model when you can. Because estimating the opportunity cost of capital is difficult,* ***only a fool throws away useful information****. That means you should not use any one model or measure mechanically and exclusively. Beta is helpful as one tool in a kit, to be used in parallel with DCF models or other techniques for interpreting capital market data. (italics in original) (emphasis added)*

* * *

Reliance on multiple tests recognizes that no single methodology produces a precise definitive estimate of the cost of equity. As stated in Bonbright, Danielsen, and Kamerschen (1988), *'no single or group test or technique is conclusive.'* (italics in original)

* * *

> **While it is certainly appropriate to use the DCF methodology to estimate the cost of equity, there is no proof that the DCF produces a more accurate estimate of the cost of equity than other methodologies.** Sole reliance on the DCF model ignores the capital market evidence and financial theory formalized in the CAPM and other risk premium methods. **The DCF model is one of many tools to be employed in conjunction with other methods to estimate the cost of equity.** It is not a superior methodology that supplants other financial theory and market evidence. The broad usage of the DCF methodology in regulatory proceedings in contrast to its virtual disappearance in academic textbooks does not make it superior to other methods. The same is true of the Risk Premium and CAPM methodologies. (emphasis added)[28]

Finally, Brigham and Gapenski note:

> In practical work, *it is often best to use all three methods* – CAPM, bond yield plus risk premium, and DCF – and then apply judgment when the methods produce different results. People experienced in estimating equity capital costs recognize that both careful analysis and some very fine judgments are required. It would be nice to pretend that these judgments are unnecessary and to specify an easy, precise way of determining the exact cost of equity capital. Unfortunately, this is not possible. Finance is in large part a matter of judgment, and we simply must face this fact. (italics in original)[29]

In the academic literature cited above, three methods are consistently mentioned: the DCF, CAPM, and the RPM, all of which I used in my analyses.

Q. ARE THERE SPECIFIC EXAMPLES WHERE THE PA PUC HAS CONSIDERED MULTIPLE COST OF COMMON EQUITY MODELS?

A. Yes. In Docket No. R-2013-2360798, concerning Columbia Water Company ("Columbia"), where I was Columbia's ROE witness, the Commission stated:

> Based on our review of the testimony, data, and cost models presented, we believe that the evidence in this case supports an ROE finding in the reasonable range of 9.25% to 10.25% using the DCF method as the foundation. The equity-heavy capital structure of Columba indicates that a slightly lower ROE is appropriate. However, the small size of the Company, its management effectiveness, and the results of other ROE

[28] Roger A. Morin, Modern Regulatory Finance, Public Utilities Reports, Inc., 2021 (Morin), at 476-479.

[29] Eugene F. Brigham and Louis C. Gapenski, Financial Management – Theory and Practice, 4th Ed. (The Dryden Press, 1985) at 256.

> models other than the DCF are all reasons to set a higher ROE. Therefore, within our indicated range of reasonableness, we conclude that an ROE of 9.75% is appropriate for our ratemaking determinations herein.

Also, in Docket No. R-2014-2402324 concerning Emporium Water Company ("Emporium"), where I was Emporium's ROE witness, the Commission stated the following:

> The ALJ recommended that the Commission adopt the Company's proposed return on common equity of 11.05%.[Footnote Omitted] R.D. at 11. The ALJ explained that the Company's position allows it to pay its debt service, which includes principal payments and interest, and provides a modest return on equity ($34,000). The ALJ states that I&E's and the OCA's positions fail to meet the standards set by the *Hope* and *Bluefield* by not even allowing the Company to pay their debt service, which may lead to possible default on the loans and the bankruptcy of the Company. R.D. at 35.
>
> * * *
>
> As discussed, *supra*, the OCA recommends a return of 9.10% as the midpoint of its DCF and CE analyses; I&E recommends a return of 8.89% based on its DCF analyses; and the Company proposes a return of 10.3%, which utilizes its DCF, RP, and CAPM analyses to which the Company adds a size risk adjustment of 75 basis points. Based on our review of the testimony, data, and cost models presented, and considering our adoption of a 60% / 40% hypothetical capital structure, we believe that the range of returns provided in evidence supports an ROE finding of 10.0% for our ratemaking determinations herein.

Lastly, in Docket Nos. R-2021-3027385 and R-2021-3027386 concerning Aqua, the Commission stated:

> Therefore, our methodology for determining Aqua's ROE shall utilize both I&E's DCF and CAPM methodologies. As noted above, the Commission recognizes the importance of informed judgment and information provided by other ROE models. In the *2012 PPL Order*, the Commission considered PPL's CAPM and RP methods, tempered by informed judgment, instead of DCF-only results. We conclude that methodologies other than the DCF can be used as a check upon the reasonableness of the DCF derived ROE calculation. Historically, we have relied primarily upon the DCF methodology in arriving at ROE determinations and have utilized the results of the CAPM as a check upon the reasonableness of the DCF derived equity return. As such, where evidence based on other methods suggests that the DCF-only results may understate the utility's ROE, we will consider those other methods, to some degree, in determining the appropriate range of

> reasonableness for our equity return determination. In light of the above, we shall determine an appropriate ROE for Aqua using informed judgement based on I&E's DCF and CAPM methodologies.[30]

In the Commission Orders cited above, there is clear language that the Commission considers multiple models in its determination of ROE. It is also my interpretation of these Orders that the Commission correctly observes capital market conditions and their effect on the model results in determining an ROE for utility companies.

Q. MR. KELLER SAYS THAT THE PRPM WAS PUBLISHED IN 2011.[31] DOES THAT MEAN THAT THE METHODOLOGY BEHIND THE PRPM WAS ALSO PUBLISHED IN 2011?

A. No. As discussed in my Direct Testimony,[32] the PRPM is based on the research of Robert F. Engle, dating back to the early 1980s. Dr. Engle discovered that the volatility of market prices, returns and risk premiums clusters over time, making prices, returns and risk premiums highly predictable. In 2003, he shared the Nobel Prize in Economics for this work, characterized as "methods of analyzing economic time series with time-varying volatility ("ARCH").[33] Dr. Engle[34] noted that relative to volatility, "the standard tools have become the ARCH / GARCH[35] models." Hence, the methodology is <u>not</u> new.

In addition, the GARCH methodology has been well tested by academia, since Engle's, *et al*. research was originally published in 1982, over 40 years ago. I use the well-established GARCH methodology to estimate the PRPM model using a standard commercial and relatively inexpensive statistical package, Eviews,© to develop a means by which to

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30 *Pa. PUC v. Aqua Pennsylvania, Inc.,* Docket Nos. R-2021-3027385 & R-2021-3027386, pp. 154-155 (Order entered May 16, 2022).

31 Keller Direct Testimony, at 39.

32 D'Ascendis Direct Testimony, at 27-28.

33 www.nobelprize.org.

34 Robert Engle, "GARCH 101: The Use of ARCH / GARCH Models in Applied Econometrics", *Journal of Economic Perspectives*, Volume 15, No. 4, Fall 2001, p. 157-168.

35 Autoregressive Conditional Heteroskedasticity / Generalized Autoregressive Conditional Heteroskedasticity.

estimate a predicted equity risk premium, and when added to a bond yield, results in a cost of common equity.

The PRPM is also in the public domain, having been published six times in academically peer-reviewed journals: Journal of Economics and Business (June 2011 and April 2015),[36] The Journal of Regulatory Economics (December 2011),[37] The Electricity Journal (May 2013 and March 2020),[38] and Energy Policy (April 2019).[39] Notably, none of these articles have been rebutted in the academic literature.

Finally, the PRPM was presented to a number of utility industry/regulatory/academic groups including the following: The Edison Electric Institute Cost of Capital Working Group; The NARUC Staff Subcommittee on Accounting and Finance; The National Association of Electric Companies Finance/Accounting/Taxation and Rates and Regulations Committees; the NARUC Electric Committee; The Wall Street Utility Group; the Indiana Utility Regulatory Commission Cost of Capital Task Force; the Financial Research Institute of the University of Missouri Hot Topic Hotline Webinar; and the Center for Research and Regulated Industries Annual Eastern Conference on two occasions.

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[36] Eugene A. Pilotte and Richard A. Michelfelder, "Treasury Bond Risk and Return, the Implications for the Hedging of Consumption and Lessons for Asset Pricing", *Journal of Economics and Business*, June 2011, 582-604; and Richard A. Michelfelder, "Empirical Analysis of the Generalized Consumption Asset Pricing Model: Estimating the Cost of Capital", *Journal of Economics and Business*, April 2015, 37-50.

[37] Pauline M. Ahern, Frank J. Hanley, and Richard A. Michelfelder, "New Approach to Estimating the Equity Risk Premium for Public Utilities", *The Journal of Regulatory Economics*, December 2011, at 40:261-278.

[38] Richard A. Michelfelder, Pauline M. Ahern, Dylan W. D'Ascendis, and Frank J. Hanley, "Comparative Evaluation of the Predictive Risk Premium Model, the Discounted Cash Flow Model and the Capital Asset Pricing Model for Estimating the Cost of Common Equity", The Electricity Journal, April 2013, at 84-89; and Richard A. Michelfelder, Pauline M. Ahern, and Dylan W. D'Ascendis, "Decoupling, Risk Impacts and the Cost of Capital", *The Electricity Journal,* January 2020.

[39] Richard A. Michelfelder, Pauline M. Ahern, and Dylan W. D'Ascendis, "Decoupling Impact and Public Utility Conservation Investment", *Energy Policy*, April 2019, 311-319.

Q. HAS THE PRPM BEEN IMPLICITLY ACCEPTED BY OTHER REGULATORY COMMISSIONS?

A. Yes. In Docket No. 2017-292-WS, the Public Service Commission of South Carolina ("PSC SC") accepted Carolina Water Services' entire requested ROE, which included the PRPM. The relevant portion states:

> The Commission finds Mr. D'Ascendis' arguments persuasive. He provided more indicia of market returns, by using more analytical methods and proxy group calculations. Mr. D'Ascendis' use of analysts' estimates for his DCF analysis is supported by consensus, as is his use of the arithmetic mean. The Commission also finds that Mr. D'Ascendis' non-price regulated proxy group more accurately reflects the total risk faced [by] price regulated utilities and CWS. Furthermore, there is no dispute that CWS is significantly smaller than its proxy group counterparts, and, therefore, it may present a higher risk. An appropriate ROE for CWS is 10.45% to 10.95%. The Company used an ROE of 10.5% in computing its Application, a return on the low end of Mr. D'Ascendis' range, and the Commission finds that ROE is supported by the evidence.[40]

In addition, in Docket No. W-354, Subs 363, 364 and 365, the State of North Carolina Utilities Commission ("NCUC") approved my RPM and CAPM analyses, which used PRPM analyses as presented in this proceeding. The relevant portion of the order states:

> In doing so the Commission finds that the DCF (8.81%), Risk Premium (10.00%) and CAPM (9.29%) model results provided by witness D'Ascendis, as updated to use current rates in D'Ascendis Late-Filed Exhibit No. 1, as well as the risk premium (9.57%) analysis of witness Hinton, are credible, probative, and are entitled to substantial weight as set forth below.[41]

Q. MR. KELLER POSITS THAT YOU USE PROPRIETARY SOFTWARE TO CONDUCT YOUR PRPM.[42] IS THAT TRUE?

A. No. The GARCH methodology is available in various statistical packages such as EViews®, SAS, RATS, S-Plus and JMulti, which are not cost-prohibitive and provide instructions for

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40 PSC SC Docket No. 2017-292-WS - Order No. 2018-345, at 14. (May 17, 2018)

41 NCUC Docket No. W-354, Sub 363, 364, 365, *Order Granting Partial Rate Increase and Requiring Customer Notice*, at PDF 72 (March 31, 2020).

42 Keller Direct Testimony, at 39-40.

using the various statistical methodologies in their software. I provided all parties in these proceedings the backup data to run their own GARCH models. While the software I used in this proceeding costs approximately $2,375 for a single user commercial license,[43] JMulti is a free downloadable software with GARCH estimation applications.

Q. THE I&E ROE WITNESSES DO NOT AGREE WITH YOUR USE OF THE ECAPM. PLEASE RESPOND.[44]

A. I disagree. As discussed in my Direct Testimony,[45] although numerous tests of the CAPM have confirmed its validity, it has been determined that the empirical Security Market Line ("SML") described by the traditional CAPM is not as steeply sloped as the predicted SML. Tests of the CAPM have measured the extent to which security returns and betas are related as predicted by the CAPM, thus confirming its validity. As such, the ECAPM should be used in a CAPM analysis.

Q. IS THERE ADDITIONAL EVIDENCE THAT SUPPORTS THE VALIDITY OF THE ECAPM?

A. Yes, there is. The empirical issues with the CAPM have been present since the presentation of the model, as noted by Dianna R. Harrington in her text Modern Portfolio Theory & the Capital Asset Pricing Model:

> So far we have learned some very interesting things about the CAPM and reality. Some of the earliest work tested realized data (history) against data generated by simulated portfolios. Early studies by Douglas (1969) and Lintner (Douglas [1969]) showed discrepancies between what was expected on the basis of the CAPM and the actual relationships that were apparent in the capital markets. Theoretically, the minimal rate of return from the portfolios (the intercept) and the actual risk-free rate for the period should have been equal. They were not.

* * *

[43] http://www.eviews.com/general/prices/prices.html

[44] *See,* Keller Direct Testimony at 40; Patel Direct Testimony at 47.

[45] D'Ascendis Direct Testimony, at 35-36.

Another study, now more famous than Lintner's was done by Black, Jensen, and Scholes (1972). Lintner had used what is called a cross-sectional method (looking at a number of stock returns during one time period), whereas Black, Jensen, and Scholes used a time-series method (using returns for a number of stocks over several time periods). To make their test, Black, Jensen, and Scholes assumed that what had happened in the past was a good proxy for the investor expectations (a frequent assumption in CAPM tests). Using historical data, they generated estimates using what we call the market model:

$$R_{jt} = \alpha_j + \beta_j (R_{mt}) + \varepsilon_j$$

Where:
R = total returns
β = the slope of the line (the incremental return for risk)
α = the intercept or a constant (expected to be 0 over time and across all firms)
ε = an error term (expected to be random, without information)
m = the market proxy
j = the firm or portfolio
t = the time period

Instead of using single stocks, they formed portfolios in an effort to wash out one source of error; because betas of single firms are quite unstable.

On the basis of the CAPM, they expected to find

1. That the intercept was equal to the risk-free rate (their proxy was the Treasury bill rate)
2. That the capital market line had a positive slope and that riskier (higher beta) securities provided higher return

Instead they found

1. That the intercept was different from the risk-free rate
2. That high-risk securities earned less and low-risk securities earned more than predicted by the model
3. That the intercept seemed to depend on the beta of any asset: high-beta stocks had a different intercept than low-beta stocks

* * *

Fama and MacBeth (1974) criticized the Black, Jensen, and Scholes study (hereafter called BJS). In a reformulation of the study, they supported the first of the BJS findings. They found that the intercept exceeded the risk-free proxy, but did not find the evidence to support the other BJS conclusions.[46]

Harrington discusses Black's potential solution to this phenomenon:

[46] Dianna R. Harrington, Modern Portfolio Theory & the Capital Asset Pricing Model – A User's Guide, Prentice-Hall, Inc. 1983, at 43-45.

> Black's replacement for the risk-free asset was a portfolio that had no covariability with the market portfolio. Because the relevant risk in the CAPM is systematic risk, a risk-free asset would be the one with no volatility relative to the market – that is, a portfolio with a beta of zero. All investor-perceived levels of risk could be obtained from various linear combinations of Black's zero-beta portfolio and the market portfolio… Since R_z (the rate of return of the zero-beta asset) and R_m are uncorrelated (as R_f and R_m were assumed to be in the simple CAPM), the investor can choose from various combinations of R_z and R_m. On segment R_mY, R_z, is sold short and proceeds are invested in R_m. On segment R_zR_m, portions of the zero-beta portfolio are purchased. At R_m, the investor is fully invested in the market portfolio. The equilibrium CAPM was rewritten by Black as follows:
>
> $$E(R_i) = (1 - \beta_i) E(R_z) + \beta_i E(R_m)$$
>
> Where:
>
> E indicates expected,
> $E(R_z)$ is less than $E(R_m)$, and
> R_z holdings over the whole market must be in equilibrium. That is, the number of short sellers and lenders of securities must be equal.
>
> Black's adaptation is intriguing. The result of using this model is a capital market line that has a less steep slope and a higher intercept than those of the simple CAPM. If Black's model is more correct in its description of investor behavior in the marketplace, then the use of the simple model would produce equity return predictions that would be too low for sticks with betas greater than one and too high for stocks with betas of less than one.[47]

As such, while I still find the CAPM to be appropriate, if the I&E ROE Witnesses are of the opinion that the CAPM is not reliable,[48] they should have applied an ECAPM analysis.

Q. HAVE OTHER JURISDICTIONS CONSIDERED THE ECAPM?

A. Yes, it has been accepted in Alaska, Minnesota, Mississippi, Nevada, New York, and Virginia.[49]

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47 Dianna R. Harrington, Modern Portfolio Theory & the Capital Asset Pricing Model – A User's Guide, Prentice-Hall, Inc. 1983, at 30-31.

48 Keller Direct Testimony at 22; Patel Direct Testimony at 22-23.

49 The Regulatory Commission of Alaska, Docket P-97-7, Order Rejecting 1997, 1998, 1999 and 2000 Filed TAPS Rates; Setting Just and Reasonable Rates; Requiring Refunds and Filings; and Outlining Phase II Issues, November 27, 2002, at 146; Minnesota Public Utilities Commission, MPUC Docket No. G011/GR-15-736, In the Matter of the Application of Minnesota Energy Resources Corporation for Authority to Increase Rates for Natural Gas Service in Minnesota, Findings of Fact, Conclusions of Law, and Recommendation, August 19, 2016, at 29; Mississippi Public Service Commission, Docket No. 01-UN-0548, Notice of Intent of Mississippi Power Company to Change Rates for Electric Service in its Certificated Areas

Q. DO YOU AGREE WITH THE I&E ROE WITNESSES' OPINION[50] THAT THE 10-YEAR TREASURY NOTE IS SUPERIOR TO THE 30-YEAR TREASURY BOND IN THE CAPM?

A. No, I do not. As discussed below, the tenor of the risk-free rate used in the CAPM should match the life (or duration) of the underlying investment. As noted by Morningstar:

> The traditional thinking regarding the time horizon of the chosen Treasury security is that it should match the time horizon of whatever is being valued. When valuing a business that is being treated as a going concern, the appropriate Treasury yield should be that of a long-term Treasury bond. Note that the horizon is a function of the investment, not the investor. If an investor plans to hold stock in a company for only five years, the yield on a five-year Treasury note would not be appropriate since the company will continue to exist beyond those five years.[51]

Morin also confirms this when he states:

> [b]ecause common stock is a long-term investment and because the cash flows to investors in the form of dividends last indefinitely, the yield on very long-term government bonds, namely, the yield on 30-year Treasury bonds, is the best measure of the risk-free rate for use in the CAPM (footnote omitted)… The expected common stock return is based on long-term cash flows, regardless of an individual's holding time period.[52]

Pratt and Grabowski recommend a similar approach to selecting the risk-free rate: "In theory, when determining the risk-free rate and the matching ERP you should be matching the risk-free security and the ERP with the period in which the investment cash flows are

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in the Twenty-Three Counties of Southeast Mississippi, Final Order, December 3, 2001, at 19; Public Utilities Commission of Nevada, Docket No. 20-02023, Application of Southwest Gas Corporation for authority to increase its retail natural gas utility service rates for Southern and Northern Nevada, Order, September 23, 2020, at 35; New York Public Service Commission, Case 16-G-0058, Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of KeySpan Gas East Corporation d/b/a National Grid for Gas Service, Order Adopting Terms of Joint Proposal and Establishing Gas Rate Plans, December 16, 2016, at 32; In the Matter of Application of Virginia Electric and Power Company, d/b/a Dominion Energy North Carolina for Adjustment of Rates and Charges Applicable to Electric Service in North Carolina, Docket No. E-22, Sub 562 Order Accepting Public Staff Stipulation in Part, Accepting CIGFUR Stipulation, Deciding Contested Issues, and Granting Partial Rate Increase, February 24, 2020, at 40.

50 Keller Direct Testimony, at 41; Patel Direct Testimony, at 43-44.

51 Morningstar, Inc., 2013 Ibbotson Stocks, Bonds, Bills and Inflation Valuation Yearbook, at 44.

52 Morin, at 169.

expected."[53] As a practical matter, equity securities represent a perpetual claim on cash flows; 30-year Treasury bonds are the longest-maturity securities available to match that perpetual claim. The I&E ROE Witnesses' use of a medium-term Treasury bond does not match the life of the assets being valued. The use of a 30-year Treasury bond is the more appropriate risk-free rate.

Q. THE I&E ROE WITNESSES CLAIM THAT LONG-TERM GOVERNMENT BONDS ARE SUBJECT TO MATURITY RISK.[54] PLEASE COMMENT.

A. They are mistaken. If a long-term Treasury note is held to maturity, there is no risk (the investor will get the stated coupon rate and principal at the end). Since the cost of equity is a long-term concept, the investment horizon of an individual investor is irrelevant.

Q. MR. PATEL BELIEVES THAT YOUR CALCULATED MARKET RETURNS AND MRPS ARE TOO HIGH.[55] PLEASE RESPOND.

A. Even though Mr. Patel questions the reasonableness of my calculated market returns and MRPs, they are consistent with actual realized returns and MRPs, as shown on Table 4, below, and Schedule DWD-4R.

Table 4: Percentile Ranks of Calculated Market Returns and Risk Premiums[56]

	D'Ascendis Testimony	%	Percentile Rank
Average Market Return	Direct	12.70%	47th
Average Market Return	Rebuttal	13.46%	48th
Average Market Risk Premium	Direct	8.15%	48th
Average Market Risk Premium	Rebuttal	8.86%	50th

53 Shannon Pratt and Roger Grabowski, Cost of Capital: Applications and Examples, 3rd Ed. (Hoboken, NJ: John Wiley & Sons, Inc., 2008), at 92. "ERP" is the Equity Risk Premium.
54 Keller Direct Testimony, at 41; Patel Direct Testimony, at 43.
55 Patel Direct Testimony, at 45-46.
56 Schedule DWD-4R.

Chart 3: Frequency Distribution of Observed Market Returns, 1926 - 2024[57]

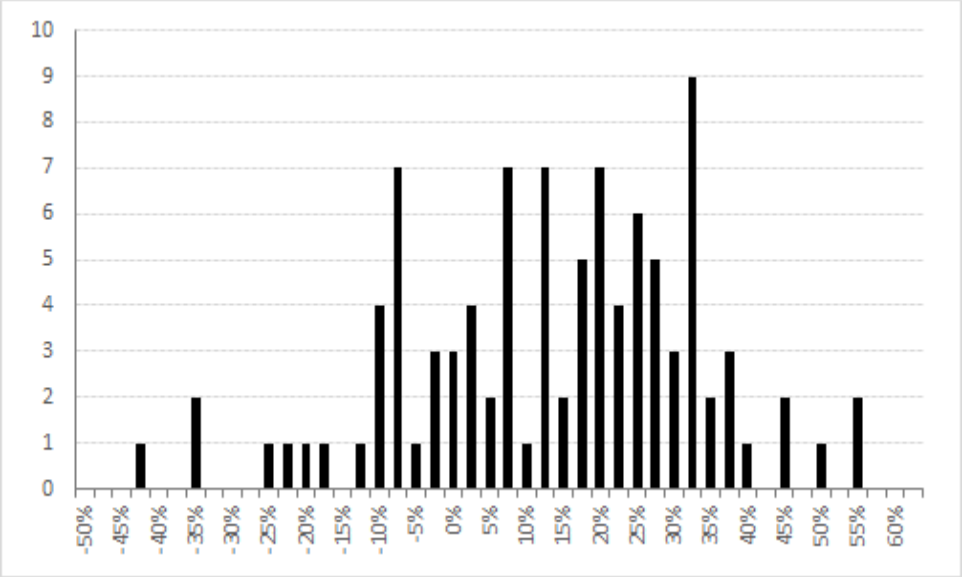
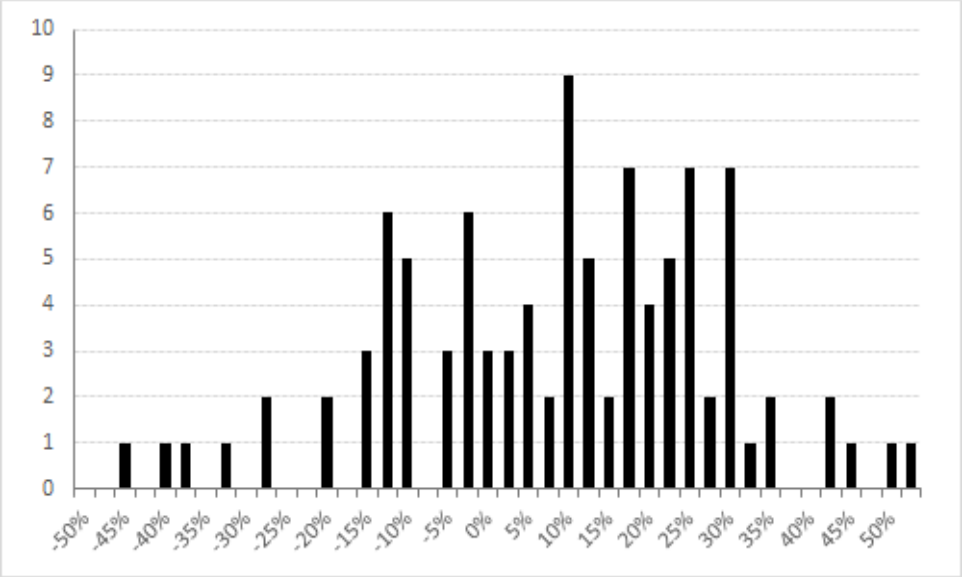


Chart 4: Frequency Distribution of Observed Market Risk Premiums, 1926 - 2024[58]



I will also note that Mr. Keller's calculated MRP of 8.99% exceeds my updated MRP of 8.86%. Given all of the above, my calculation of the market returns and MRPs

[57] Schedule DWD-4R.
[58] *Id.*

are consistent with observed values and values used by I&E in their own analysis. Thus, Mr. Patel's concern should be dismissed.

Q. THE I&E ROE WITNESSES STATE THAT THE SELECTION AND USE OF NON-PRICE REGULATED GROUPS COMPARABLE IN TOTAL RISK TO THE UTILITY PROXY GROUPS IS SPECULATIVE AND SUBJECTIVE.[59] PLEASE RESPOND.

A. The selection criteria for my Non-Price Regulated Proxy Group were based on ranges of two measures of risk: (1) the unadjusted beta of the Utility Proxy Group, which measures systematic, or market risk; and (2) the standard error of the regression, which gave rise to those betas, measuring non-systematic or diversifiable risk. Systematic plus non-systematic risk is one definition of total risk.[60] This is agreed upon by Mr. Keller and Mr. Patel, who state in their testimony: "two types of risk are associated with a stock: (1) firm-specific risk (unsystematic risk); and (2) market risk (systematic risk), which is measured by a firm's beta."[61]

Each company I selected for my Non-Price Regulated Proxy Group was required to have an unadjusted beta (a measure of systematic risk) and a standard error of the regression (a measure of unsystematic risk) within the ranges generated by my proxy group, as explained in page 46 of my Direct Testimony and on Schedule DWD-6.

Business and financial risks may vary between companies and proxy groups, but if the collective average betas and standard errors of the regression of the group are similar, then the total, or aggregate, non-diversifiable market risks and diversifiable risks are similar, as noted in "Comparable Earnings: New Life for an Old Precept" provided in

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59 Keller Direct Testimony, at 36.
60 Business risk plus financial risk is a second definition of total risk.
61 Keller Direct Testimony, at 18; Patel Direct Testimony, at 19.

Schedule DWD-5R. Thus, because the non-price regulated companies are selected based on analyses of market data, they are comparable in total risk (even though individual risks may vary) to my Utility Proxy Group. This is demonstrated clearly on page 273 of Jack C. Francis' Investments: Analysis and Management (page 3 of Schedule DWD-6R), which shows that total risk can be "partitioned into its systematic and unsystematic components." Essentially, companies that have similar betas and standard errors of regression have similar total investment risk.

Q. HAVE YOU CONDUCTED ANY ADDITIONAL ANALYSES TO DETERMINE WHETHER YOUR UTILITY PROXY GROUP AND NON-PRICE REGULATED PROXY GROUP ARE OF COMPARABLE RISK?

A. Yes, I have. I compared the average and median *Value Line* Safety Ranking, the annualized volatility of stock returns, and the Coefficient of Variation ("CoV")[62] of net profit for the Utility Proxy Group and Non-Price Regulated Proxy Group, as shown on Table 5, below:

[62] The CoV, which is a measure of relative volatility, equals the standard deviation divided by the average.

Table 5: Comparison of Safety Rankings, CoV of Net Profit, and Annualized Volatility of Mr. D'Ascendis' Utility Proxy Groups and Non-Price Regulated Proxy Groups

Group	Average Safety Ranking	Median Safety Ranking	Average CoV Net Profit	Median CoV Net Profit	Average Annualized Volatility	Median Annualized Volatility
Gas Proxy Group	1.88	2.00	0.31	0.16	23.83%	24.42%
Non-Price Regulated Proxy Group (Gas)	1.68	2.00	0.61	0.12	23.84%	23.61%
Electric Proxy Group	1.79	2.00	0.11	0.10	21.31%	20.60%
Non-Price Regulated Proxy Group (Electric)	1.38	1.00	0.13	0.11	22.89%	23.00%

As shown, the Safety Rankings, annualized volatility of their stock returns, and CoV of net profit of the Utility Proxy Groups and the Non-Price Regulated Proxy Groups are comparable or lower, indicating comparable or lower total risk. This, in addition to all of the above, should lead the Commission to consider the results of my Non-Price Regulated Proxy Groups as another measure of the Companies' ROE in this proceeding.

Q. MR. KELLER CRITICIZES THE USE OF YOUR NON-PRICE REGULATED PROXY GROUPS BECAUSE THE RESULTS OF THE MODELS APPLIED TO THE GROUPS ARE NOT SIMILAR TO THE RESULTS OF THE SAME MODELS APPLIED TO YOUR UTILITY PROXY GROUPS.[63] PLEASE RESPOND.

A. The role of regulation when setting rates for a utility company is to simulate a competitive market and the returns that the regulator approves should be commensurate with the rates of return earned by firms with comparable risk. That being said, the ranges of the indicated ROEs produced by the common equity models applied to the Utility Proxy Group and Non-Price Regulated Proxy Group in my ROE update do mostly overlap as shown below:

[63] Keller Direct Testimony, at 43.

Table 6: Comparison of Model Results Applied to Mr. D'Ascendis' Gas and Non-Price Regulated Proxy Groups

	DCF	RPM	CAPM
D'Ascendis Gas Proxy Group	9.00% - 11.41%	10.72%	10.51% - 11.29 %
Non-Regulated Group Comparable to Gas Group	6.40% - 15.15%	11.27%	10.05% - 11.83%

Table 7: Comparison of Model Results Applied to Mr. D'Ascendis' Electric and Non-Price Regulated Proxy Groups

	DCF	RPM	CAPM
D'Ascendis Electric Proxy Group	8.13% - 10.90%	10.70%	9.66% - 11.13%
Non-Regulated Group Comparable to Electric Group	7.22% - 12.30%	11.11%	10.05% - 11.83%

Given the indicated ranges of results of cost of common equity models applied to the Utility Proxy Groups and Non-Price Regulated Proxy Groups, the objective of the comparable earnings model, and the adherence to the regulatory compact, the results of market models applied to the Non-Price Regulated Proxy Groups comparable in total risk to my Utility Proxy Groups should be accepted by the Commission.

Q. THE I&E ROE WITNESSES BOTH NOTE THEY ARE UNAWARE OF ANY AUTHORIZED ROES IN THE LAST TWO YEARS ABOVE YOUR REQUESTED ROE OF 11.65%.[64] PLEASE COMMENT.

A. While authorized ROEs may be reasonable benchmarks of acceptable ROEs in static economic conditions, they can mis-specify the investor-required return in a dynamic economic environment, such as this one. The reason why historical authorized returns mis-specify the investor-required return in changing markets is because authorized ROEs are a lagging indicator of investor-required returns; i.e., authorized ROEs are based on market data presented in an evidentiary record, which spans a period before the decision, lasting over a year in some cases. Because markets are constantly changing, historical authorized

[64] Keller Direct Testimony, at 54; Patel Direct Testimony, at 59-60.

returns do not completely reflect the investor required return because the economic conditions in the past are not representative of economic conditions now. That is, what investors require in the future may not correlate to what they required and/or received in the past. We must remember that projecting the investor required ROE is a forward-looking concept. Because this is the case, the I&E ROE Witnesses' observations regarding historically allowed ROEs are of little value.

IV. RESPONSE TO OCA WITNESS WALTERS

Q. PLEASE SUMMARIZE MR. WALTERS' RECOMMENDATION REGARDING THE COMPANIES' OVERALL COST OF CAPITAL.

A. Like the I&E ROE Witnesses, Mr. Walters accepts the Companies' requested capital structures and debt cost rates.[65] Regarding the return on common equity, Mr. Walters recommends an ROE of 9.50%, within a range of 9.00% to 10.00%.[66] Mr. Walters' range is derived using three versions of the DCF model, a risk premium model, and the CAPM.

Q. DO YOU HAVE ANY GENERAL COMMENTS ON MR. WALTERS' RECOMMENDED RANGE OF ROES AND THE INDICATED RESULTS OF HIS MODELS?

A. Yes, I do. As shown on Chart 5 below and in Schedule DWD-7R, the indicated results of Mr. Walters' cost of equity models generally exceed his recommended range of common equity cost rates and his recommended point estimate of 9.50%. As shown on Schedule DWD-7R, Mr. Walters provided 20 individual cost of equity estimates; six DCF results; five RPM results; and nine CAPM results. Of those results, only three of those are below his recommended range, while ten exceed the top of his range, and 17 of 20 of his indicated

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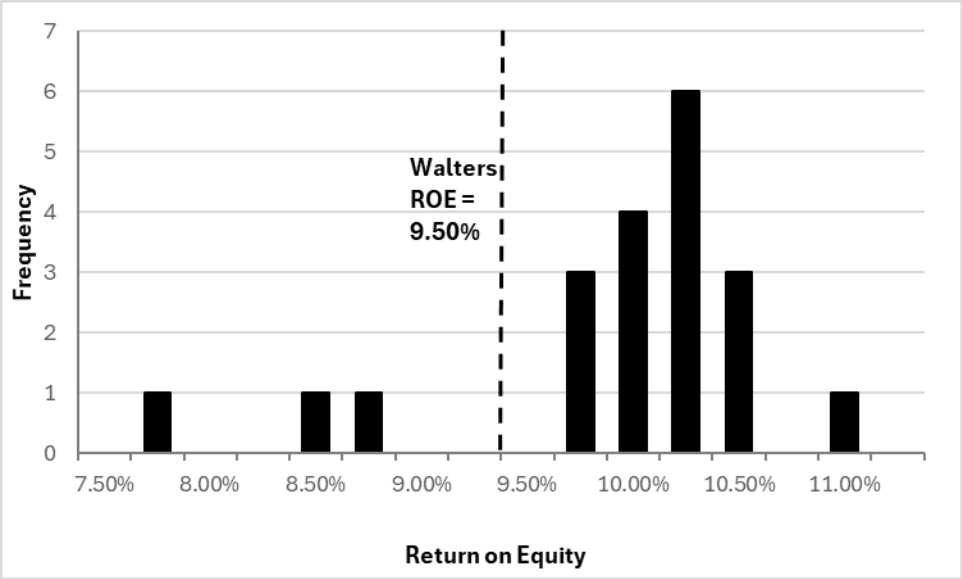
65 Walters Direct Testimony, at 23-24.

66 *Id.* at 3.

results exceed his recommended ROE of 9.50%. While I do not agree with Mr. Walters' application of his models, as will be explained in detail below, his own model results indicate a higher ROE for the Companies than he ultimately recommends.

Chart 5: Histogram of Walters Indicated Model Results and Ultimate Range and Recommendation



Q. WHAT ARE THE AREAS OF DISAGREEMENT BETWEEN YOU AND MR. WALTERS?

A. The principal areas in which I disagree with Mr. Walters include: (1) his contention that utilities are maintaining their credit quality despite being awarded lower ROEs; (2) specific inputs to his DCF model; (3) the assumptions and methods underlying his RPM; (4) specific assumptions and inputs to his CAPM; and (5) his decision to not reflect any flotation costs.

A. RELEVANCE OF HISTORICAL AUTHORIZED RETURNS

Q. YOUR RECOMMENDED ROE OF 11.65% IS ABOVE THE AVERAGE ROE APPROVED FOR UTILITIES OVER THE PAST SEVERAL YEARS. ARE HISTORICAL ROES A GOOD MEASURE OF PROSPECTIVE ROES?

A. No, they are not. As I discussed previously, while authorized ROEs may be reasonable benchmarks of acceptable ROEs, they do not reflect the current cost of common equity.

Q. IS THERE A WAY TO USE HISTORICAL AUTHORIZED RETURNS TO DERIVE A MEASURE OF THE INVESTOR REQUIRED RETURN?

A. Yes, there is. A useful way to use historical authorized ROEs for cost of capital purposes would be to determine whether a relationship between authorized ROEs (or equity risk premiums) and interest rates exists so one can determine an expectational ROE or equity risk premium given an interest rate. Studies by Harris and Marston (2001) and Brigham, Dilip, Shone, and Vinson (1985) indicate an inverse relationship between equity risk premiums and interest rates (i.e., as interest rates move, equity risk premiums move in the opposite direction, but not to the extent of the interest rate move) as discussed in my Direct Testimony.[67]

As shown on pages 35 and 36 of Schedule DWD-1R, using historical authorized ROEs and interest data in regression analyses produces statistically significant inverse relationships between interest rates and equity risk premiums, which can be used to determine expectational investor-required returns. Given an expectational A2-rated Public Utility bond yield of 5.71%, indicated equity risk premiums of 4.74% and 4.78% are calculated using natural gas and electric historical ROE data, respectively. Adding the expectational

[67] D'Ascendis Direct Testimony, at 32.

A2-rated public utility bond yield to those equity risk premiums results in indicated ROEs of 10.45% and 10.49%, respectively.

Q. MR. WALTERS STATES THAT UTILITY COMPANIES HAVE BEEN ABLE TO MAINTAIN THEIR CREDIT QUALITY DESPITE DECLINING AUTHORIZED ROES.[68] DO YOU AGREE?

A. No, I do not. Although Mr. Walters' statements regarding a supportive credit environment for utilities sounds reasonable, a closer look reveals that not to be the case. For example, in January of 2025, S&P noted:

> In 2024, downgrades among North America's investor-owned regulated utilities outpaced upgrades for the fifth consecutive year (see Chart 8). Most were directly attributable to rising wildfire risks, robust capital spending, and challenging regulatory constructs. We expect those risks to persist for 2025, further pressuring the industry's credit quality.[69]

Mr. Walters often provides the degradation of the credit quality of the utility industry over the recent period in a table in his direct testimony but does not in this proceeding. I have reproduced Mr. Walters' table from his testimony in Ameren Illinois, in which both of us were involved (Direct Testimony filed May 8, 2025).

Table 8: Mr. Walters' Table CCW-3 in Docket No. 25-0084 Concerning Ameren Illinois Company S&P Ratings by Category Natural Gas Subsidiaries[70]

Rating	2020	2025
A or higher	38%	5%
A-	38%	25%
BBB+	13%	52%
BBB	13%	17%
BBB-	0%	2%

As shown in the table above, since 2020, there has been significant downward movement in industry credit ratings. The number of BBB and BBB+ rated utilities has increased.

[68] Walters Direct Testimony, at 7-9.

[69] S&P Global Ratings: Industry Credit Outlook 2025 – North America Regulated Utilities, January 14, 2025.

[70] Illinois Corporation Commission, Docket No. 25-0084, Direct Testimony of Christopher C. Walters, at 8.

That shift toward lower credit ratings indicates a deteriorating credit environment for the utility industry and consequently increases overall investment risk.

B. DISCOUNTED CASH FLOW MODEL ANALYSES

Q. PLEASE SUMMARIZE MR. WALTERS' DCF ANALYSES.

A. Mr. Walters uses three DCF models; a constant growth DCF, a sustainable growth DCF analysis, and a MSDCF, all using price data for the 13-week period ending May 30, 2025. For his projected three- to five-year EPS growth rates, Mr. Walters uses Zacks, S&P Capital IQ Market Intelligence, and I/B/E/S; and he uses *Blue Chip* for the terminal growth rate in his MSDCF.[71] Using these inputs, he derives indicated ROEs between 10.31% and 10.79% for his constant growth DCF models, 9.57% and 9.59% for his sustainable growth DCF, and between 8.39% and 8.62% for his MSDCF model. From these results, Mr. Walters concludes that more weight should be placed on his sustainable growth DCF and MSDCF models.[72]

Q. DO YOU HAVE ANY CONCERNS WITH MR. WALTERS' APPLICATION OF THE DCF MODEL AND HIS INTERPRETATION OF HIS RESULTS?

A. Yes, I do. I have concerns with (1) his reasoning to discount his constant growth DCF using analysts' growth; (2) his use of "sustainable" growth rates in a DCF model, and (3) his use of the MSDCF.

Q. PLEASE SUMMARIZE MR. WALTERS' COMMENTS AS THEY RELATE TO THE REASONABLENESS OF ANALYST GROWTH RATES IN THE CONSTANT GROWTH DCF MODEL.

A. Mr. Walters argues that "[A]lthough there may be short-term peaks, the long-term sustainable growth rate for a utility stock cannot exceed the growth rate of the economy in

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71 Walters Direct Testimony at 31-40.

72 *Id.* at 42-43

which it sells its goods and services."[73] Mr. Walters estimates the growth rate in GDP to be 4.09% relative to the 6.87% average growth rate based on analysts' growth rates in his constant growth DCF model.[74]

Q. WHY IS LONG-TERM GROWTH IN GDP NOT AN UPPER LIMIT FOR GROWTH, AS MR. WALTERS CONTENDS?

A. First, GDP is not a market measure – Rather it is a measure of the value of the total output of goods and services excluding inflation in an economy. While I understand that EPS growth is also not a market measure, it is well established in the financial literature that projected growth in EPS is the superior measure of dividend growth in a DCF model.[75] Furthermore, GDP is the sum of all private industry and government output in the United States, and its growth rate is simply an average of the value of those industries. To illustrate, Schedule DWD-8R presents the compound growth rate of the industries that comprise GDP from 1947 to 2024. Of the 15 industries represented, seven industries, including utilities, grew faster than the overall GDP, and eight industries grew slower than the overall GDP.[76] Because of this, the GDP growth rate cannot be an upper limit for long-term growth, as several industries have grown faster than GDP for extended periods of time.

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73 *Id.* at 34.

74 *Id.*

75 Robert Harris, *Using Analysts' Growth Forecasts to Estimate Shareholder Required Rate of Return*, Financial Management, Spring 1986; Christofi, Christofi, Lori and Moliver, *Evaluating Common Stocks Using Value Line's Projected Cash Flows and Implied Growth Rate*, Journal of Investing, Spring 1999; Robert Harris and Felicia Marston, *Estimating Shareholder Risk Premia Using Analysts' Growth Forecasts*, Financial Management, Summer 1992; and Vander Weide and Carleton, *Investor Growth Expectations: Analysts vs. History*, The Journal of Portfolio Management, Spring 1988.

76 Source of Information: Bureau of Economic Analysis.

Q. HOW DOES THE UTILITY PROXY GROUP'S GROWTH RATE COMPARE TO THE HISTORICAL GROWTH RATE OF THE UTILITY INDUSTRY FOR THE PERIOD 1947 TO 2024?

A. The average growth rate used in my updated DCF analysis is 6.55%, which is comparable to the long-term growth rate of the utility industry of 6.47%. The comparability of these growth rates reinforces the maturity of the industry and that the MSDCF model is not needed.

Q. DID YOU CONDUCT ANOTHER ANALYSIS THAT CALCULATES THE AMOUNT OF TIME IT WOULD TAKE AN INDUSTRY TO OVERTAKE THE ENTIRE ECONOMY?

A. Yes. I examined the value added by industry from 1947 to 2024 in Schedule DWD-8R and used the compound annual growth rates for the highest growth rate industry (Educational Services, Healthcare, and Social Assistance, 8.55% / year) to see when that industry would comprise the entire economy. In the year 2300, or 353 years from the 1947 starting point, the industry would comprise over 50% of GDP; and in the year 7963, or 6,016 years after the 1947 starting point, the industry would comprise 100% of GDP.[77] Not only have individual companies or industries consistently grown at rates beyond GDP growth, but they have done so without overtaking the entire economy. While Mr. Walters' argument is technically correct, it is unrealistic at best.

[77] To put the amount of time that will take these two milestones to happen in perspective, approximately 300 years ago, in the year 1719, France and Spain were at war in New France (now Louisiana), and approximately 3,482 years ago, in the year 1457 BC, the first recorded battle in military history, the Battle of Megiddo, was waged between the Egyptians, led by Pharaoh Thutmose III against Kadesh, Canaanite, Mitanni, and Amurru forces. *See also* Zager and Evans, *In the Year 2525*, *on* 2525 (Exordium & Terminus) (RCA 1968).

Q. DO YOU AGREE WITH MR. WALTERS'APPLICATION OF A SUSTAINABLE GROWTH RATE?

A. No, I do not. Professor Morin discusses the sustainable growth model and shows that it relies on knowledge of several factors, including:

- "b": the fraction of earnings per share retained;
- "r": the rate of return on equity (ROE);
- "s": the growth rate in common equity due to the sale of stock; and
- "v": the fraction of a stock sale that increases existing book value.

Specifically, Professor Morin states the following:

> There are three problems in the practical application of the sustainable growth method:
>
> (1) It may be even more difficult to estimate what b, r, s and v investors have in mind than it is to estimate what g[rowth] they envisage. It would appear far more economical and expeditious to use available growth forecasts and obtain g directly instead of relying on four individual forecasts of the determinants of such growth. *It seems only logical that the measurement and forecasting errors inherent in using four different variables to predict growth far exceed the forecasting error inherent in a direct forecast of growth itself*.
>
> (2) *There is an element of circularity in estimating g by a forecast of b and ROE for the utility being regulated, since ROE is determined in large part by regulation. To estimate what ROE resides in the minds of investors is equivalent to estimating the market's assessment of the outcome of regulatory hearings.* Expected ROE is exactly what regulatory commissions set in determining an allowed rate of return. In other words, the method requires an estimate of ROE before it can even be implemented. *Common sense would dictate the inconsistency of a return on equity recommendation that is different than the expected ROE that the method assumes the utility will earn forever.*
>
> For example, using an expected return on equity of 11% to determine the growth rate and using that same growth rate to recommend a return on equity of 9% is inconsistent. *It is not reasonable to assume that this regulated utility company is expected to earn 11% forever, but estimate a 9% return on equity. The only way this utility can earn 11% is that rates be set by the regulator so that the utility will in fact earn 11%....*

> (3) The empirical finance literature discussed earlier demonstrates that the sustainable growth method of determining growth is not as significantly correlated to measures of value, such as stock price and price/earnings ratios, as other historical growth measures or analysts' growth forecasts. *Other proxies for growth, such as historical growth rates and analysts' growth forecasts, outperform retention growth estimates.* (Emphasis and clarification added.)[78]

The circular nature of the sustainable growth DCF is illustrated in the following steps:

1. The sustainable growth rate relies on an expected ROE on book common equity;
2. That expected ROE on book common equity is then used in a DCF analysis to establish an ROE cost rate related to the market value of the common stock; and
3. That market-related ROE, if authorized as the allowed ROE in a regulatory proceeding, becomes the expected ROE on book common equity.

Put simply, the estimated ROEs Mr. Walters used to derive his sustainable growth rate become the regulatory outcome of this proceeding, even as those ROEs are themselves based on regulatory outcomes.

Q. DOES INDEPENDENT RESEARCH SUPPORT THE FINDING THAT FUTURE EARNINGS AND THE RETENTION RATIO ARE NOT POSITIVELY RELATED?

A. Yes. In 2006, for example, two articles in Financial Analysts Journal addressed the theory that high dividend payouts (i.e., low retention ratios) are associated with low future earnings growth.[79] Both articles cite a 2003 study by Arnott and Asness,[80] who found that

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[78] Morin, at 383-384.

[79] *See*, Ping Zhou, William Ruland, *Dividend Payout and Future Earnings Growth*, Financial Analysts Journal, Vol. 62, No. 3, 2006. *See also*, Owain ap Gwilym, James Seaton, Karina Suddason, Stephen Thomas, *International Evidence on the Payout Ratio, Earnings, Dividends and Returns*, Financial Analysts Journal, Vol. 62, No. 7, 2006.

[80] *See*, Robert Arnott, Clifford Asness, *Surprise: Higher Dividends = Higher Earnings Growth*, Financial Analysts Journal, Vol. 59, No. 1, January/February 2003.

over the course of 130 years of data, future earnings growth is associated with high, rather than low, payout ratios.[81] In essence, the findings of all three studies found that there is a negative, not a positive, relationship between the two.

Q. DID YOU PERFORM ANY ANALYSES TO TEST THAT ASSUMPTION?

A. Yes, I did. Using EPS and DPS data from *Value Line*, I calculated the historical dividend payout ratio, retention ratio, and subsequent five-year average earnings growth rate for the companies included in the *Value Line* electric, natural gas and water utility industry. I then performed a regression analysis in which the dependent variable was the five-year earnings growth rate, and the explanatory variable was the earnings retention ratio. The purpose of that analysis was to determine whether the data empirically supports the assumption that higher retention ratios necessarily produce higher earnings growth rates.

Q. WHAT DID THAT ANALYSIS REVEAL?

A. As shown in Schedule DWD-9R and Table 9, below, there was a statistically significant negative relationship between the five-year average earnings growth rate and the earnings retention ratio. That is, based on *Value Line* data, earnings growth actually decreased as the retention ratio increased. Those findings clearly call into question Mr. Walters' use of the sustainable growth rate as a proxy for the long-term growth rate in his analysis.

[81] Because the payout ratio is the inverse of the retention ratio, the authors found that future earnings growth is negatively related to the retention ratio.

Table 9: Retention Ratio / Earnings Growth[82]

	Coefficient	Standard Error	t-Statistic
Intercept	0.1540	0.0106	14.5753
Retention Ratio	-0.2704	0.0211	-12.7862

Q. DO THOSE RESULTS MAKE PRACTICAL SENSE?

A. Yes, they do. As a practical matter, dividend-paying companies such as utilities are reluctant to reduce dividends, given the often-disproportionate stock price reaction. Consequently, a higher-than-expected dividend increase may signal to investors that management has confidence in higher future earnings and cash flow. That is, a near-term reduction in the retention ratio supporting a higher dividend increase may provide information or "signaling" content regarding future growth prospects.[83] In view of the foregoing, Mr. Walters' use of a retention ratio growth rate DCF analysis is an exercise in circularity which ignores the basic principle of rate base/rate of return regulation.

Q. IS MR. WALTERS' MSDCF MODEL A REASONABLE APPROACH TO ESTIMATING THE COMPANY'S ROE?

A. No, it is not. The MSDCF model and its growth rates reflect the company/industry lifecycle, which is typically described in three stages: (1) the growth stage, which is characterized by rapidly expanding sales, profits, and earnings. In the growth stage, dividend payout ratios are low in order to grow the firm; (2) the transition stage, which is characterized by slower growth in sales, profits, and earnings. In the transition stage, dividend payout ratios increase, as their need for exponential growth diminishes; and (3) the maturity (steady-state) stage, which is characterized by limited, slightly attractive

82 Schedule DWD-9R.

83 *See,* Eugene F. Brigham, Louis C. Gapenski, Financial Management, Theory and Practice, Seventh Ed., 1994, at 618.

investment opportunities, and steady earnings growth, dividend payout ratios, and returns on equity.

Q. ARE THERE EXAMPLES IN BASIC FINANCE TEXTS THAT SUPPORT YOUR POSITION?

A. Yes. For example, in *Investments*, life cycles and multi-stage growth models are discussed:

> As useful as the constant-growth DDM (dividend discount model) formula is, you need to remember that it is based on a simplifying assumption, namely, that the dividend growth rate will be constant forever. In fact, firms typically pass through life cycles with very different dividend profiles in different phases. In early years, there are ample opportunities for profitable reinvestment in the company. Payout ratios are low, and growth is correspondingly rapid. In later years, the firm matures, production capacity is sufficient to meet market demand, competitors enter the market, and attractive opportunities for reinvestment may become harder to find. In this mature phase, the firm may choose to increase the dividend payout ratio, rather than retain earnings. The dividend level increases, but thereafter it grows at a slower pace because the company has fewer growth opportunities.
>
> Table 18.2 illustrates this pattern. It gives Value Line's forecasts of return on assets, dividend payout ratio, and 3-year growth in earnings per share for a sample of the firms in the computer software industry versus those of east coast electric utilities…
>
> By in large, the software firms have attractive investment opportunities. The median return on assets of these firms is forecast to be 19.5%, and the firms have responded with high plowback ratios. Most of these firms pay no dividends at all. The high return on assets and high plowback result in rapid growth. The median growth rate of earnings per share in this group is projected at 17.6%.
>
> In contrast, the electric utilities are more representative of mature firms. Their median return on assets is lower, 6.5%; dividend payout is higher, 68%; and median growth is lower, 4.6%.
>
> ***
>
> To value companies with temporarily high growth, analysts use a multistage version of the dividend discount model. Dividends in the early high-growth period are forecast and their combined present value is calculated. Then, once the firm is projected to settle down to a steady-growth phase, the

> constant-growth DDM is applied to value the remaining stream of dividends.[84]

The economics of the public utility business indicates that the industry is in the steady-state, or constant-growth stage of a MSDCF. This means that the three- to five-year projected growth rates for each company would be the "steady-state" or terminal growth rate appropriate for the DCF model for utility companies, not the GDP growth rate, which is not a company-specific growth rate, nor is it an upward bound for growth.

Q. WHAT ARE YOUR CONCLUSIONS AS THEY RELATE TO MR. WALTERS' DCF ANALYSIS?

A. First, Mr. Walters' MSDCF model is inappropriate to rely on given that utilities are in the steady state growth stage. As such, the MSCF results should be ignored. Second, Mr. Walters' use of "sustainable" growth rates in his DCF analysis is an exercise in circularity which ignores the basic principle of rate base / rate of return regulation. Namely the expected ROE from which the growth rate is derived is used to generate an ROE for regulatory purposes. Also, empirical tests show that the basis of the sustainable growth DCF (i.e., higher retention rates lead to higher growth) is not true in reality. Therefore, Mr. Walters' constant growth DCF model results are the only relevant ROEs presented and the only ones that the Commission should consider in this proceeding.

C. <u>RISK PREMIUM METHOD</u>

Q. PLEASE BRIEFLY DESCRIBE MR. WALTERS' RPM.

A. Mr. Walters defines the "Risk Premium" as the difference between average annual authorized equity returns for utilities and a measure of long-term interest rates each year from 1986 through 2025.[85] Mr. Walters' first approach to estimating the RPM looks to the

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[84] Z. Bodie, A. Kane, and A. J. Marcus, *Investments*, 7th Edition, McGraw-Hill Irwin, 2008, at 616-617

[85] Walters Direct Testimony, at 44.

30-year Treasury yield, and his second considers the average A-rated utility bond yield.[86] In each case, Mr. Walters establishes his risk premium estimate by reference to historical averages.

Mr. Walters looks to 40 years of returns, arguing "a relatively long period of time where stock valuations reflect premiums to book value indicates that the authorized ROEs and the corresponding equity risk premiums were supportive of investors' return expectations."[87] Mr. Walters considers the current and projected capital markets when selecting equity risk premiums ("ERP") of 5.50% (over Treasury bonds) and 4.16% (over Utility bonds).[88] Applying a forecasted 30-year Treasury yield and 13- and 26-week average A-rated and Baa-rated public utility bond yields to those ERPs result in indicated ROEs ranging from 9.97% to 10.30%.[89]

Q. DO YOU HAVE SPECIFIC CONCERNS WITH MR. WALTERS' APPLICATION OF THE RPM?

A. Yes. I have three concerns with Mr. Walters' analysis, namely: (1) the use of the 1986 – 2025 time period; (2) Mr. Walters' method and recommendation ignore an important relationship revealed by his own data, i.e., that there is an inverse relationship between ERPs and interest rates (whether measured by U.S. Treasury bonds or public utility bond yields); and (3) his mismatched application of projected Treasury bond yields and current utility bond yields.

86 *Id.* at 44-45.
87 *Id.* at 45.
88 *Id.* at 48-49.
89 *Id.* at 50.

Q. WHAT ARE YOUR CONCERNS WITH MR. WALTERS 1986 – 2025 TIME PERIOD TO DETERMINE AN ERP?

A. Mr. Walters selected the period 1986 – 2025 "because public utility stocks consistently traded at a premium to book value during that period."[90] He concludes that "[o]ver this period, an analyst can infer authorized ROEs were sufficient to support market prices that at least exceeded book value."[91] Mr. Walters is mistaken. Market values can diverge from book values for a myriad of reasons including earnings per share ("EPS") and dividends per share ("DPS") expectations, merger / acquisition expectations, interest rates, etc. As noted by Phillips:[92]

> Many question the assumption that market price should equal book value, believing that 'the earnings of utilities should be sufficiently high to achieve market-to-book ratios which are consistent with those prevailing for stocks of unregulated companies.

In addition, Bonbright[93] states:

> In the first place, commissions cannot forecast, except within wide limits, the effect their rate orders will have on the market prices of the stocks of the companies they regulate. In the second place, whatever the initial market prices may be, they are sure to change not only with the changing prospects for earnings, but with the changing outlook of an inherently volatile stock market. In short, market prices are beyond the control, though not beyond the influence of rate regulation. Moreover, even if a commission did possess the power of control, any attempt to exercise it ... would result in harmful, uneconomic shifts in public utility rate levels. (italics added)

Also, Kroll's 2023 SBBI® Yearbook ("SBBI – 2023") makes it clear that the arbitrary selection of historical periods is highly suspect and unlikely to be representative of long-term trends in market data. For example, SBBI - 2023 states:

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90 *Id.* at 44.

91 *Id.*

92 Phillips, Charles F., The Regulation of Public Utilities – Theory and Practice (Public Utility Reports, Inc., 1993) 395.

93 James C. Bonbright, Albert L. Danielsen and David R. Kamerschen, Principles of Public Utility Rates (Public Utilities Reports, Inc., 1988) 334.

> The estimate of the equity risk premium depends on the length of the data series studied. A proper estimate of the equity risk premium requires a data series long enough to give a reliable average without being unduly influenced by very good and very poor short-term returns. When calculated using a long data series, the historical equity risk premium is relatively stable. Furthermore, because an average of the realized equity risk premium, is quite volatile when calculated using a short history, using a long series makes it less likely that the analyst can justify any number he or she wants.[94]

The academic literature demonstrates and confirms that while regulation is a substitute for marketplace competition, it has an effect on, but no direct control over market prices, and hence market-to-book ("M/B") ratios of regulated utilities. The academic literature also shows that a subset of data could be subject to data manipulation. Because of this, no valid conclusion of ERPs can be drawn for the 1986 – 2025 period.

Q. IS THERE A DIRECT RELATIONSHIP BETWEEN THE M/B RATIOS OF UNREGULATED COMPANIES AND THEIR EARNED RATES OF RETURN ON BOOK COMMON EQUITY?

A. No. Since regulation acts as a surrogate for competition, it is reasonable to look to the competitive environment for evidence of a direct relationship between M/B ratios and earned returns on common equity. To determine if Mr. Walters' implicit assumption of such a direct relationship has any merit, I observed the M/B ratios and the earned returns on common equity of the S&P Industrial Index, and the S&P 500 Composite Index, over a long period of time. In Schedule DWD-10R, I have shown the M/B ratios, rates of return on book common equity (earnings / book ratios), annual inflation rates, and the earnings / book ratios net of inflation (real rate of earnings) annually for the years 1947 through 2024. In each year, the M/B ratios of the S&P Industrial Index equaled or exceeded 1.00 times (or 100%). In 1949, the only year in which the M/B ratio was 1.00, the real rate of earnings

94 SBBI – 2023 at 193-194.

on book equity, adjusted for deflation, was 18.10% (16.30% + 1.80%). In contrast, in 1961, when the S&P Industrial Index experienced an M/B ratio of 2.01 times, the real rate of earnings on book equity for the S&P Industrial Index was only 9.10% (9.80%-0.70%). In 1997, the M/B ratio for the Index was 5.88 times, while the average real rate of earnings on book equity was 22.90% (24.60%-1.70%).

This analysis clearly demonstrates that competitive, unregulated companies have never sold below book value, on average, and have sold at book value in only one year since 1947. Because this lack of a relationship between earnings / book ratios and M/B ratios covers a 78-year period, 1947 through 2024, it cannot be validly argued that going forward a relationship would exist between earnings / book ratios and M/B ratios. The analysis shown in Schedule DWD-10R coupled with the supportive academic literature, demonstrate the following: (1) that while regulation is a substitute for marketplace competition, it can influence, but not directly control market prices, and hence, M/B ratios; and (2) that the rates of return investors expect to achieve, and which influence their willingness to pay market prices well in excess of book values have no meaningful, direct relationship to rates of earnings on book equity. Because of this, no valid conclusion of ERPs can be drawn for the 1986-2025 period because of M/B ratios in excess of one.

Q. DOES MR. WALTERS' RPM ANALYSIS IGNORE THE INVERSE RELATIONSHIP BETWEEN ERPS AND INTEREST RATES?

A. Yes. Reviewing the data in Exhibits CCW-10 and CCW-11, I discovered that the ERP as presented by Mr. Walters tends to move inversely with changes in interest rates. In other words, as interest rates fall, the ERP increases.

Q. HOW DOES MR. WALTERS' DATA SHOW THE INVERSE RELATIONSHIP BETWEEN ERPS AND INTEREST RATES?

A. As shown in Schedule DWD-11R, empirical analyses of the data presented in Exhibits CCW-10 and CCW-11, ERPs have moved inversely with changes in U.S. Treasury bond yields for 1986 – 2024.

When looking at the inverse relationship between ERP and interest rates, as shown on Schedule DWD-11R, which uses Mr. Walters' data, the R-squareds are in excess of 82%. This means that the movement in interest rates explains over 82% of the movement in ERP, which I would consider to be a strong relationship.[95]

Q. MR. WALTERS USED CURRENT A- AND BAA-RATED PUBLIC UTILITY BOND YIELDS IN HIS RPM ANALYSIS. PLEASE COMMENT.

A. Mr. Walters' use of a Baa-rated public utility bond yield is incorrect for two reasons. First, Mr. Walters applies a Baa-rated public utility bond yield to an ERP derived from A-rated public utility bonds, improperly matching the ERP measured relative to A-rated public utility bond yields with a Baa rated public utility bond yield. Second, Mr. Walters' use of current A- and Baa-rated public utility bond yield is inconsistent with his entire return on common equity analysis. For example, Mr. Walters used an expected risk-free rate in both his CAPM analysis and his U.S. Treasury Bond-based ERP analysis, analyst projections of EPS and sustainable growth in his constant growth DCF model applications and projected inflation in his derivation of his projected market ERP. For internal consistency in his analyses and to be theoretically correct, as well as consistent with the prospective nature of both ratemaking and the cost of capital, a projected A-rated public utility bond yield should be used in Mr. Walters' RPM analysis.

[95] I also note the t-statistics from these analyses indicate the relationship is highly statistically significant.

Q. HOW CAN A PROJECTED A-RATED PUBLIC UTILITY BOND YIELD BE ESTIMATED?

A. One source is *Blue Chip's*[96] forecasts of Aaa corporate bond yields adjusted to reflect a recent spread between A-rated public utility bond and Aaa corporate bond yield. *Blue Chip* forecasts Aaa-rated corporate bonds to yield an average 5.25%, based upon an average of the six quarters ending with the third quarter of 2026 and 2027– 2031 and 2032– 2036. However, the 5.25% projected Aaa corporate bond yield needs to be adjusted to estimate an equivalent A-rated public utility bond yield. Using a three-month average bond yield spread (approximately 13 weeks, consistent with Mr. Walters' analysis), an upward adjustment of 46 basis points is necessary, resulting in a prospective A-rated public utility bond yield of 5.71% as derived on page 5 of Schedule DWD-11R.

Q. PLEASE SUMMARIZE THE RANGE OF RPM INDICATED COMMON EQUITY COST RATES AFTER CORRECTING MR. WALTERS' RPM ANALYSIS.

A. As shown on Schedule DWD-11R, applying a projected risk-free rate of 4.56% and prospective A2-rated public utility bond yield of 5.71%[97] to the regression equations in Schedule DWD-11R produces results of 5.94% and 4.69%, respectively, for the electric utilities, and 5.88% and 4.63%, respectively, for the natural gas utilities. This results in an ROE of 10.50% and 10.40% for electric utilities using the projected 30-year Treasury and the prospective A-rated public utility bond yield, respectively, and ROE of 10.44% and 10.34%, respectively, for natural gas utilities. As discussed previously, while I do not agree with Mr. Walters' basic RPM, the corrected RPM results based upon regression analyses of his data are more appropriate indicators of common equity cost rate.

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96 *Blue Chip* is a source relied upon by Mr. Walters for projected inflation in developing his projected MRP for his CAPM analysis.

97 *See, Blue Chip Financial Forecasts*, June 2, 2025, at 2, 14.

D. CAPITAL ASSET PRICING MODEL

Q. PLEASE BRIEFLY SUMMARIZE MR. WALTERS' CAPM ANALYSIS AND RESULTS.

A. Mr. Walters' CAPM analysis combines three estimates of the MRP and three estimates of beta, along with his projected risk-free rate of 4.50% from *Blue Chip*[98] to calculate nine CAPM estimates that range from 7.29% to 11.08%.[99]

Mr. Walters' first MRP estimate is based on the historical average real market return over the 1926-2024 period as reported by Morningstar Direct, combined with an expected inflation rate of 2.50% to calculate an expected market return of 11.75%. Subtracting his 4.50% projected risk-free rate results in an MRP of 7.20%.[100]

In the second calculation, he applies a modified version of FERC's DCF method to the S&P 500 Index to calculate the total expected market return. Mr. Walters calculates the weighted average dividend yield and growth rate for each company in the S&P 500, excluding non-dividend paying companies and companies with growth rates that are negative or above 20%. Mr. Walters then applies a one-half growth rate adjustment to the resulting dividend yield to arrive at the expected dividend yield for the S&P 500 of 1.79%. Adding the expected dividend yield to the weighted average growth rate of 10.80% results in a market return of 12.19%.[101] Subtracting his 4.50% projected risk-free rate from his DCF-based market return of 12.19% results in an MRP of 7.70%.[102] Mr. Walters then performed the same analysis including all companies in the S&P 500, which resulted in an MRP of 8.09%.[103]

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98 Walters Direct Testimony, at 51.
99 *Id.*at 63
100 *Id.* at 57-58.
101 *Id.* at 58; Exhibit CCW-15, page 2.
102 *Id*.
103 *Id.* at 59; Exhibit CCW-15, page 2.

Mr. Walters' final MRP is the 5.50% "normalized" MRP recommended by Kroll.[104]

Q. IS MR. WALTERS' CAPM METHODOLOGY AND RESULT SOUND?

A. No. Mr. Walters' CAPM analysis is flawed in at least four respects: (1) while Mr. Walters does use a short-term projected risk-free rate in his CAPM analysis, he does not consider the long-term projection of the risk-free rate published by *Blue Chip*; (2) he relies, in part, on Vasicek betas; (3) his choice and calculation of his MRP are flawed; and (4) he did not perform an ECAPM analysis.

Q. DOES MR. WALTERS RELY ON *BLUE CHIP* THROUGHOUT HIS ANALYSIS?

A. Yes, he does. Specifically, Mr. Walters uses *Blue Chip* for his short-term projected interest yield on 30-year Treasury bonds for his CAPM analysis, his terminal growth rate in his MSDCF model analysis, and also discusses five- and ten-year projected interest rates in the capital markets section of his direct testimony.[105] Because of Mr. Walters' reliance on *Blue Chip*, I find it curious that he does not use the long-term projections published by *Blue Chip* for his analysis.

Not incorporating the longest projection available is inconsistent with Mr. Walters' application of the DCF model in which there is an assumption that the projected "g" is constant into perpetuity, creating a mismatch between the application of his models. It is also inconsistent with the Efficient Market Hypothesis ("EMH").

Q. WHAT IS THE EMH?

A. According to Eugene F. Fama,[106] a market in which prices always "fully reflect" available information is called "efficient." There are three forms of the EMH, namely:

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104 *Id.* at 62.

105 Walters Direct Testimony, at 39-40, 48.

106 Eugene F. Fama, *Efficient Capital Markets: A Review of Theory and Empirical Work*, The Journal of Finance, Vol. 25, No. 2. (May 1970), at 383-417.

- The "weak" form asserts that all past market prices and data are fully reflected in securities prices. In other words, technical analysis cannot enable an investor to "outperform the market."
- The "semi-strong" form asserts that all publicly available information is fully reflected in securities prices. In other words, fundamental analysis cannot enable an investor to "outperform the market."
- The "strong" form asserts that all information, both public and private, is fully reflected in securities prices. In other words, even insider information cannot enable an investor to "outperform the market."

The "semi-strong" form is generally considered the most realistic because the illegal use of insider information can enable an investor to "beat the market" and earn excessive returns, thereby disproving the "strong" form. The semi-strong form of the EMH assumes that all information (including long-term forecasts of interest rates) is available to the investor, which means the long-term forecasted interest rate would be considered by investors when making investment decisions and, therefore, should be included in Mr. Walters' CAPM analysis.

Q. DO YOU AGREE WITH MR. WALTERS' USE OF VASICEK-ADJUSTED BETAS IN HIS CAPM ANALYSIS?

A. No, I do not. First, Vasicek-adjusted betas are not widely available in the market or known to investors as compared to Blume-adjusted betas. Second, the Vasicek adjustment looks to standard errors of betas; the higher the standard error, the less reliable the beta estimate is, and the larger the adjustment of the beta to the market, peer group, or industry average beta. While the Vasicek-adjusted beta adjusts beta toward the industry average, it does not account for the tendency of low-beta stocks to understate expected risk. Third and finally, Duff & Phelps cites to a Delaware Court of Chancery decision that may support that more

extreme betas tend to revert to the industry mean over time,[107] but Mr. Walters has provided no evidence that utility betas are extreme, nor has he provided any evidence that utility betas do not revert to 1.0.

Q. DO YOU AGREE WITH MR. WALTERS' USE OF HISTORICAL BETAS IN HIS CAPM ANALYSIS?

A. No, I do not. The determination of the ROE is a measure of the investor expected return at any given point of time using current and expected measures. The use of historical betas is neither current nor expected. The analytical models that form the basis of the recommended ROE represent a snapshot of the Companies' investor-required return at the time of the analysis and should not be normalized based on speculation that current market conditions may change in the future that are not based on publicly-available data.

Q. WHAT IS YOUR POSITION ON THE 5.00% MRP QUOTED BY KROLL?

A. A forecast is only as good as its inputs, and if the assumptions within those forecasts are by its nature unpredictable (e.g. productivity growth forecasts), they are of little value. In addition, the determination of the MRP as calculated by Kroll is not transparent, especially in view of the historical data presented in SBBI – 2023, or the composition of its supply side method, which are already well known by investors. Because of the transparency of the historical data and how to gather and use the components of the supply side model, both the historical MRP (using the long-term arithmetic mean return on large company stocks less the long-term arithmetic income returns on long-term Government bonds) and the supply side model are superior measures of the MRP, when comparing to Kroll's simplistic and opaque MRP forecast.

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[107] Duff & Phelps Investment Analyzer, 2020, Chapter 5, at 8.

Q. DID YOU CONDUCT A STUDY TO DETERMINE THE FORECAST ACCURACY OF THE KROLL RECOMMENDED MARKET RETURN RELATIVE TO THE HISTORICAL MARKET RETURNS THEY PUBLISH?

A. Yes, I did. I have calculated the forecast bias[108] of the long-term historical average return and the implied market returns from Kroll from 2009-2024.[109] For example, the long-term average market return from 1926-2008 was used to determine the forecasted return for 2009. The result of this analysis is shown in Schedule DWD-12R and Table 10, below:

Table 10: Comparison of Forecast Bias for Various Measures 2009-2024

Year	Observed Market Return	Long-Term Average Return	Kroll Forecasted Market Return
2009	26.46%	11.67%	10.50%
2010	15.06%	11.85%	10.08%
2011	2.11%	11.88%	9.63%
2012	16.00%	11.77%	10.00%
2013	32.39%	11.82%	9.50%
2014	13.69%	12.05%	9.00%
2015	1.38%	12.07%	9.00%
2016	11.96%	11.95%	9.00%
2017	21.83%	11.95%	9.00%
2018	-4.38%	12.06%	8.50%
2019	31.49%	11.88%	9.00%
2020	18.40%	12.09%	8.00%
2021	28.71%	12.16%	8.00%
2022	-18.11%	12.33%	8.00%
2023	26.61%	12.02%	9.00%
2024	25.62%	12.16%	9.00%
Sum	249.22%	191.71%	145.71%
Forecast Bias[110]		76.93%	58.47%

As shown in Table 10, while both of these measures understate the actual return (all forecast bias values are under 100%), the Kroll forecasted market return significantly and consistently understates the actual return. The Kroll projected market return is a less

[108] Forecast bias can be described as a tendency to either over-forecast or under-forecast a given variable.

[109] 2008 was selected as the starting year as it is the first year Kroll published its recommended MRP and risk-free rate.

[110] Calculated by dividing the sum of the forecast returns by the sum of the actual returns.

accurate predictor of the actual return than the historical average return. These findings are consistent with Campbell, who states that when returns are serially uncorrelated, the arithmetic average represents the best forecast of future returns in any randomly selected future year.[111]

Q. MR. WALTERS REFERS TO EXPECTED MARKET RETURNS AS PUBLISHED BY FINANCIAL INSTITUTIONS TO SUGGEST HIS EXPECTED MARKET RETURNS SHOULD BE CONSIDERED HIGH-END ESTIMATES.[112] IS HIS COMPARISON VALID?

A. No, it is not. Expected market returns from pension funds or investment houses try to predict what the market's earned return will be, not the return that investors require in order to invest, which is the subject of this proceeding. For example, a benefit plan asset manager will match the **expected returns** available from various asset classes to the expected liabilities that must be funded. An investor seeking to maximize their risk-adjusted return will only invest in a security if the expected return is equal to or greater than the **required return**. Because *expected* returns may or may not equal *required* returns, one cannot assume pension funding assumptions or expected returns from investment houses (that is, expected returns) may be viewed as a measure of investors' required returns.

Benefit plan managers develop asset allocation and investment decisions based on expected risks and returns for various asset classes subject to the investment objective or expected timing and nature of the liabilities being funded by those investments. In the U.S., they must consider: (1) the diversification of the portfolio; (2) the liquidity and current return of the portfolio relative to the expected cash flow requirements under the plan; (3) the

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111 John Y. Campbell, "Forecasting US Equity Returns in the 21st Century," Social Security Administration, July 2001.

112 Walters Direct Testimony, at 59-60.

portfolio's projected return relative to the plan's funding objective; and (4) the return expected on alternative investments with similar risks.[113] Pension asset managers, therefore, are concerned with investing funds at an expected return to meet expected liabilities. As to the documents cited by Mr. Walters, several contain clearly stated limiting assumptions and disclaimers, which call into question their use for the purpose of setting the ROE in this proceeding. For example, Blackrock notes:

> References to future returns are not promises or even estimates of actual returns a client portfolio may achieve. Assumptions, opinions and estimates are provided for illustrative purposes only.
>
> This material has been prepared for information purposes only and is not intended to provide, and should not be relied on for, accounting, legal, or tax advice. The outputs of the assumptions are provided for illustration purposes only and are subject to significant assumptions. "Expected" return estimates are subject to uncertainty and error.[114]

Similarly, JP Morgan Chase notes:

> Assumptions, opinions and estimates are provided for illustrative purposes only. They should not be relied upon as recommendations to buy or sell securities. Forecasts of financial market trends that are based on current market conditions constitute our judgment and are subject to change without notice. We believe the information provided here is reliable, but do not warrant its accuracy or completeness.[115]

Lastly, Vanguard notes:

> The projections and other information generated by the VCMM regarding the likelihood of various investment outcomes are hypothetical in nature, do not reflect actual investment results, and are not guarantees of future results.[116]

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113 29 CFR 2509.908-1, Interpretive Bulletin Relating to Investing in Economically Targeted Investments, October 17, 2008.

114 BlackRock, Inc Capital Market Assumptions, retrieved February 17, 2025.

115 J.P. Morgan Asset Management 2024 Long-Term Capital Market Assumptions, at 150.

116 Vanguard economic and market outlook for 2025: Beyond the landing, at 2.

Q. DO YOU RECOMMEND THAT THE COMMISSION REPLACE MR. WALTERS' KROLL MRP?

A. Yes. On pages 61 and 62 of his direct testimony, Mr. Walters references two well-known Kroll MRPs: (1) the historical arithmetic mean MRP of 7.17%, and (2) the 6.22% arithmetic MRP as calculated using the supply-side model. I would recommend the Commission consider the average of those MRPs (6.70%) in favor of the opaque "recommended" Kroll MRP.

Q. DID MR. WALTERS CONDUCT AN ECAPM ANALYSIS?

A. No, he did not. Mr. Walters does not conduct an ECAPM analysis because he does not agree with the use of adjusted betas in the ECAPM.[117]

Q. WHAT IS YOUR RESPONSE TO MR. WALTERS' CONCERN WITH THE USE OF ADJUSTED BETAS IN THE ECAPM STRUCTURE?

A. Mr. Walters seems to believe that using adjusted betas in the ECAPM analysis leads to two duplicative adjustments to the expected return line.[118] To the contrary, using adjusted betas in a CAPM analysis is not equivalent to using the ECAPM nor is it a duplicative adjustment.

Betas are adjusted because of their general regression tendency to converge toward 1.0 over time, i.e., over successive calculations of beta. As also noted above, numerous studies have determined that the security market line (SML) described by the CAPM formula at any given moment in time is not as steeply sloped as the predicted SML. Morin states:

> …some critics of the ECAPM argue that the use of Value Line adjusted betas in the traditional CAPM amounts to using an ECAPM. This is incorrect. The use of adjusted betas in a CAPM analysis is not equivalent to the ECAPM. Betas are adjusted because of the regression tendency of betas to converge toward 1.0 over time.

117 Walters Direct Testimony, at 73.
118 *Id.* at 75.

* * *

> The use of an adjusted beta by Value Line is correcting for a different problem than the ECAPM. The adjusted beta captures the fact that betas regress toward one over time. The ECAPM corrects for the fact that the CAPM under-predicts observed returns when beta is less than one and over-predicts observed returns when beta is greater than one.

* * *

> Another way of looking at it is that the Empirical CAPM and the use of adjusted betas comprise two separate features of asset pricing. Assuming arguendo a company's beta is estimated accurately, the CAPM will still understate the return for low-beta stocks. Furthermore, if a company's beta is understated, the Empirical CAPM will also understate the return for low-beta stocks. Both adjustments are necessary.[119]

Moreover, the slope of the SML should not be confused with beta. As Brigham and Gapenski state:

> The slope of the SML reflects the degree of risk aversion in the economy – the greater the average investor's aversion to risk, then (1) the steeper is the slope of the line, (2) the greater is the risk premium for any risky asset, and (3) the higher is the required rate of return on risky assets.[12]
>
> [12]Students sometimes confuse beta with the slope of the SML. This is a mistake. As we saw earlier in connection with Figure 6-8, and as is developed further in Appendix 6A, beta does represent the slope of a line, but not the Security Market Line. This confusion arises partly because the SML equation is generally written, in this book and throughout the finance literature, as ki = RF + bi(kM – RF), and in this form bi looks like the slope coefficient and (kM – RF) the variable. It would perhaps be less confusing if the second term were written (kM – RF)bi, but this is not generally done.[120]

As noted in Appendix 6A of Brigham and Gapenski's textbook, beta, which accounts for regression bias, is not a return adjustment but rather is based on the slope of a different line.

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119 Morin, at 223-224.

120 Eugene F. Brigham and Louis C. Gapenski, Financial Management: Theory and Practice, The Dryden Press, 1985, at 201-204.

A 1980 study by Litzenberger, et al. found the CAPM underestimates the ROE for companies, such as public utilities, with betas less than 1.00. In that study, the authors applied adjusted betas and still found the CAPM to underestimate the ROE for low-beta companies. Similarly, Brattle Group's Risk and Return for Regulated Industries supports the use of adjusted betas in the ECAPM:

> Note that the ECAPM and the Blume adjustment are attempting to correct for different empirical phenomena and therefore both may be applicable. It is not inconsistent to use both, as illustrated by the fact that the Litzenberger et.al (1980) study relied on Blume adjusted betas and estimated an alpha of 2% points in a short-term version of the ECAPM. This issue sometimes arises in regulatory proceedings.[121]

Hence, using adjusted betas does not address the previously discussed empirical issues with the CAPM. In view of the foregoing, my use of adjusted betas in both the traditional and empirical applications of the CAPM is neither incorrect or inconsistent with the financial literature, nor is it a duplicative adjustment.

Q. WHAT WOULD THE RESULTS OF MR. WALTERS' CAPM ANALYSIS BE IF HE RELIED ON PROPER INPUTS?

A. As shown in Schedule DWD-13R, using Mr. Walters' *Value Line* betas from page 1 of CCW-15, I have corrected Mr. Walters CAPM analysis by: (1) including both the short-term and long-term projections of the 30-year Treasury yield in the estimation of the risk-free rate; (2) excluding his historical and S&P Capital IQ betas; (3) replacing the Kroll "recommended" MRP with measurable MRPs; and (4) estimating the ECAPM. Those corrections result in an average CAPM estimate of 10.64% and an average ECAPM estimate of 10.93%.

[121] Bente Villadsen, *et. al*, Risk and Return for Regulated Industries (2017) at 95, endnote 147 of Chapter 4.

E. ADJUSTMENTS TO COMMON EQUITY COST RATE

Q. DOES MR. WALTERS CONSIDER A SIZE ADJUSTMENT?

A. No, he does not. Mr. Walters does not consider a size adjustment for three reasons: (1) since the Companies are not publicly-traded, one cannot calculate a market capitalization and therefore cannot compare the Companies to the Utility Proxy Group; (2) Mr. Walters does not believe that there is a link between size and risk for utilities; and (3) that portfolio theory dictates that company-specific risks are diversifiable and would not be compensated.[122]

Q. DO YOU AGREE WITH MR. WALTERS' REASONS TO NOT INCLUDE A SIZE ADJUSTMENT?

A. No, I do not. As a preliminary matter, I have already addressed Mr. Walters' concern regarding the applicability of a size premium for utilities while discussing the I&E ROE Witnesses' direct testimonies, and I will not address that concern again here.

Regarding Mr. Walters' concern that the Companies are not publicly-traded, while that is the case, Mr. Walters determined a comparable risk proxy group to determine the ROE for the Companies. As his proxy group is assumed to be of comparable risk to the Companies, we can also assume that the Companies would have comparable market multiples (such as M/B ratios) as the average proxy group company. Because that is the case, multiplying each Company's book equity by the average M/B ratio of the comparable risk proxy group is a suitable proxy for an estimated market capitalization for the Companies.

[122] Walters Direct Testimony, at 81.

Q. WHAT IS YOUR RESPONSE TO MR. WALTERS' ASSERTION THAT THE SIZE ADJUSTMENT IS INAPPROPRIATE BECAUSE THE COMPANIES SHOULD NOT BE CONSIDERED AS STAND-ALONE ENTITIES?

A. As discussed in my Direct Testimony, the ROE in this proceeding should be set on a stand-alone basis.[123] That is, the ROE witnesses in this case are estimating the ROE for the Companies, which needs to be based on their individual risks. Consistent with the stand-alone ratemaking principle, it is reasonable and appropriate to consider the small size of the Companies relative to the companies in the Utility Proxy Group.

F. RESPONSE TO MR. WALTERS' CRITIQUES

Q. DOES MR. WALTERS HAVE ANY CRITIQUES OF YOUR ANALYSES?

A. Yes, he does. Mr. Walters' critiques of my direct testimony are as follows: (1) that I rely solely on the constant growth DCF; (2) my recommendations exceed recently authorized ROEs; (3) that my calculation of my projected A2 rated utility bond yield is not market-based; (4) the level of my ERPs and MRPs in my RPM and CAPM analyses; (5) that the PRPM is not frequently used or widely accepted; (6) my use of adjusted betas in the ECAPM model; (7) my use of non-price regulated risk proxy group; and (8) my inclusion of Company-specific premiums.

I have addressed critiques (1), (2), and (5) through (8) during the course of this Rebuttal Testimony. I will discuss Mr. Walters' remaining critiques below.

Q. MR. WALTERS STATES YOUR ESTIMATE OF THE PROJECTED A2-RATED UTILITY BOND IS NOT SUPPORTED.[124]

A. I respectfully disagree with Mr. Walters on this point. Because there are no projections of A-rated public utility bonds in the market to my knowledge, I use market data to derive an

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123 D'Ascendis Direct Testimony, at 7-8.
124 Walters Direct Testimony, at 70.

expected bond yield. Mr. Walters and I both use *Blue Chip* in our analyses, which is a trusted publication for analysts. While credit spreads are narrower than historically, as noted by Mr. Walters, that would serve to lower the indicated Risk Premium Model ("RPM") ROE in this proceeding. Likewise, current A2-rated bonds are higher than my project A2-rated bond. Because of this, my RPM result can be considered conservative.

Q. MR. WALTERS IS CONCERNED WITH INDIVIDUAL MEASURES OF YOUR ERP IN YOUR RPM.[125] PLEASE RESPOND.

A. As a preliminary matter, Mr. Walters does not critique the method or theory supporting my calculation of any ERP, just the level of the ERP. As noted by Mr. Walters in his direct testimony, since I average several ERPs to arrive at my recommended ERP, it mitigates high and low values.[126] Mr. Walters also states that "employing multiple methods helps cross-check and validate results, mitigate the impact of any one model's limitations or potentially flawed assumptions, and reduce reliance on any single uncertain output. By considering results from different perspectives, a more informed and credible estimate can be made. This approach is consistent with both sound financial practice and regulatory expectations for fair and reasonable return determinations.[127] To those points, my initial and updated ERPs are consistent with actual realized ERPs as shown on Table 11 below and in Schedule DWD-14R

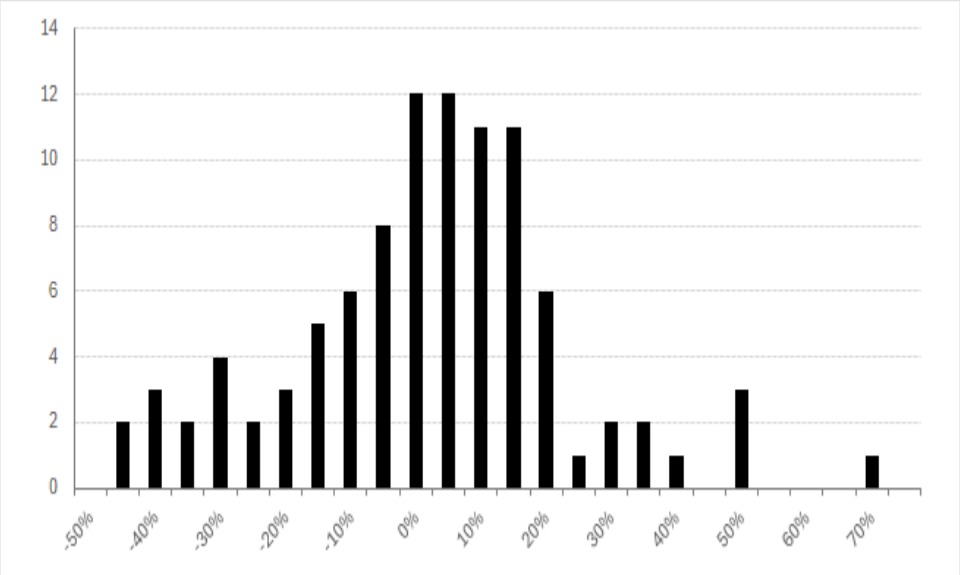
Table 11: Percentile Ranks of Calculated Equity Risk Premiums[128]

	%	Percentile Rank
Average Equity Risk Premium (Natural Gas – Direct)	5.06	49
Average Equity Risk Premium (Natural Gas – Rebuttal)	4.95	49
Average Equity Risk Premium (Electric – Direct)	4.93	49

125 *Id.*
126 *Id.*
127 *Id.* at 27-28.
128 Schedule DWD-14R.

Average Equity Risk Premium (Electric – Rebuttal)	4.86	49

Chart 6: Frequency Distribution of Equity Risk Premiums 1928-2024[129]



Given the above, my calculation of my recommended ERP is consistent with the use of multiple models, as advocated by Mr. Walters and produces a result consistent with historical experience. Mr. Walters' concerns should be dismissed.

V. RESPONSE TO OSBA WITNESS FARR

Q. PLEASE SUMMARIZE MR. FARR'S RECOMMENDATIONS REGARDING THE APPROPRIATE ROE FOR THE COMPANIES.

A. Mr. Farr does not conduct an independent assessment of the Companies' required ROE, but instead relies on the TUS quarterly calculation of the ROE used for each type of utilities' (i.e., gas, electric, water) DSIC.[130] Relying on the TUS report, Mr. Farr recommends ROEs of 10.15%, 10.00%, and 10.00% for Valley, Citizens' and Wellsboro, respectively.[131]

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129 *Id.*

130 OSBA Statement No. 1, Docket Nos. R-2025-3054394 (Citizens') 3054393 (Valley), and 3054392 (Wellsboro), at 4.

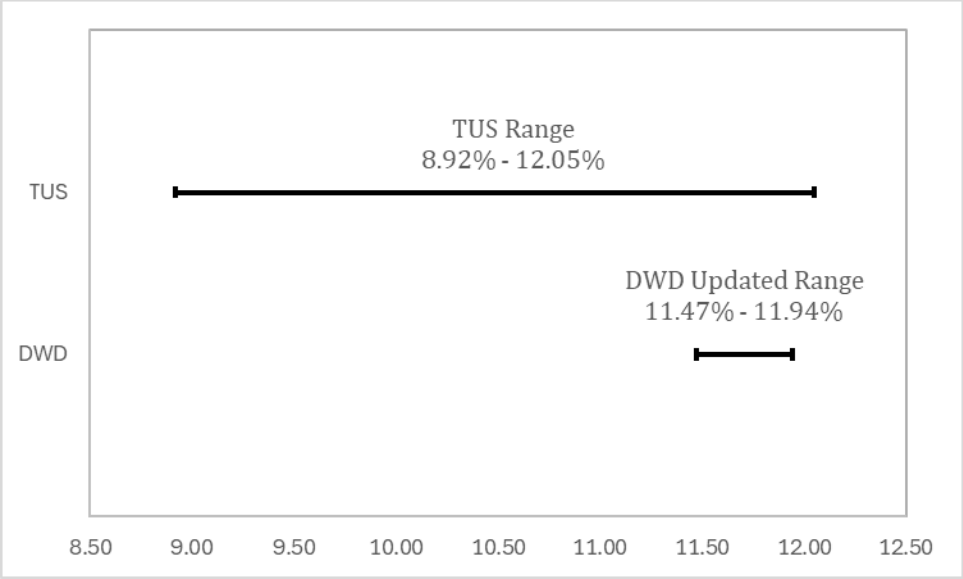
131 *Id.*

Q. DO YOU HAVE ANY OBSERVATIONS REGARDING THE TUS REPORT?

A. Yes, I do. As noted by Mr. Farr in his direct testimony, the current market ranges of indicated ROEs calculated by the TUS for gas and electric companies are from 8.92% to 12.05% and from 9.17% to 11.23%, respectively.[132] The top of both representative ranges (12.05% gas, 11.23% electric) represent one standard deviation above the mean DCF model result, which would be applicable to the Companies, given their small size and previous authorization of similar adjustments to the Companies' indicated ROEs in Docket No. R-2109-3008212 as discussed in my Direct Testimony.[133]

As shown in Charts 7 and 8 below, my recommended adjusted range overlaps TUS' indicated range of ROEs, confirming the reasonableness of my recommendation and size adjustment.

Chart 7: Comparison of TUS' Range of ROEs for Gas Utilities and D'Ascendis' Adjusted Range[134]

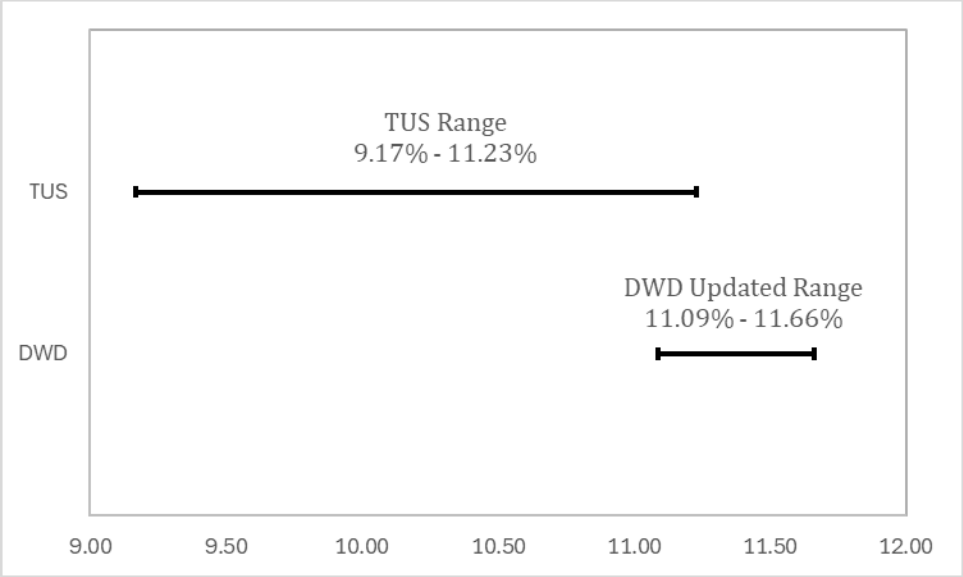


[132] Pennsylvania Public Utility Commission, Bureau of Technical Utility Services, Report on the Quarterly Earnings of Jurisdictional Utilities for the Year Ended December 31, 2024, May 8, 2025, at 18 (electric) and 23 (gas).

[133] D'Ascendis Direct Testimony, at 50-51.

[134] Pennsylvania Public Utility Commission, Bureau of Technical Utility Services, Report on the Quarterly Earnings of Jurisdictional Utilities for the Year Ended December 31, 2024, May 8, 2025, at 18 (electric) and 23 (gas).

Chart 8: Comparison of TUS' Range of ROEs for Electric Utilities and D'Ascendis' Adjusted Range[135]



VI. CONCLUSION

Q. PLEASE SUMMARIZE YOUR REBUTTAL TESTIMONY

A. Given the discussion above and my updated analysis, an ROE of 11.65% remains reasonable for the Companies at this time. The I&E ROE Witnesses' recommended ROEs fall within the range of my unadjusted ROE model results and support my recommendation. Likewise, the indicated ranges of ROEs calculated by the TUS for gas and electric utilities overlap my adjusted range of ROEs for the Companies, supporting both my indicated model results and the magnitude of my size adjustment.

Concerning Mr. Walters' recommended ROE, I discuss that the majority of his indicated results exceed his recommendation, and that his reliance on non-traditional DCF models and betas serve to significantly understate his ultimate conclusion.

135 *Id.*

Q. IN YOUR OPINION, IS YOUR PROPOSED ROE OF 11.65% FAIR AND REASONABLE FOR VALLEY AND ITS CUSTOMERS?

A. Yes, it is.

Q. IN YOUR OPINION, IS YOUR PROPOSED ROE OF 11.65% FAIR AND REASONABLE FOR CITIZENS' AND ITS CUSTOMERS?

A. Yes, it is.

Q. IN YOUR OPINION, IS YOUR PROPOSED ROE OF 11.65% FAIR AND REASONABLE FOR WELLSBORO AND ITS CUSTOMERS?

A. Yes, it is.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes, it does.

Joint Statement No. 2R

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	**:**		
	:		
v.	**:**	**Docket Nos.**	**R-2025-3054392**
	:		**R-2025-3054393**
Citizens' Electric Company of Lewisburg, PA,	**:**		**R-2025-3054394**
Valley Energy Company, and Wellsboro	**:**		
Electric Company	**:**		

EXHIBIT

OF

DYLAN W. D'ASCENDIS

ON BEHALF OF

CITIZENS' ELECTRIC COMPANY OF LEWISBURG, PA,
VALLEY ENERGY, INC., AND
WELLSBORO ELECTRIC COMPANY

AUGUST 13, 2025

Valley Energy, Inc. / Citizens' Electric Company of Lewisburg, PA / Wellsboro Electric Company
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Valley Energy, Inc. / Citizens' Electric Company of Lewisburg, PA / Wellsboro Electric Company
Recommended Capital Structure and Cost Rates
for Ratemaking Purposes

Valley Energy, Inc.

Type of Capital	Ratios(1)	Cost Rate		Weighted Cost Rate
Long-Term Debt	51.06%	5.03%	(2)	2.57%
Common Equity	48.94%	11.65%	(3)	5.70%
Total	100.00%			8.27%

Citizens' Electric Company of Lewisburg, PA

Type of Capital	Ratios(1)	Cost Rate		Weighted Cost Rate
Long-Term Debt	51.06%	5.47%	(2)	2.79%
Common Equity	48.94%	11.65%	(3)	5.70%
Total	100.00%			8.49%

Wellsboro Electric Company

Type of Capital	Ratios(1)	Cost Rate		Weighted Cost Rate
Long-Term Debt	51.06%	4.85%	(2)	2.48%
Common Equity	48.94%	11.65%	(3)	5.70%
Total	100.00%			8.18%

Notes:
(1) Capital structure based on 2024 capital structure maintained by the Companies' Parent, C&T Enterprises.
(2) Company-provided
(3) From page 2 of this Schedule.

Valley Energy, Inc. / Citizens' Electric Company of Lewisburg, PA / Wellsboro Electric Company
Brief Summary of Common Equity Cost Rate

Line No.	Principal Methods	Proxy Group of Eight Natural Gas Distribution Companies	Proxy Group of Fourteen Electric Companies
1.	Discounted Cash Flow Model (DCF) (1)	10.42%	10.19%
2.	Risk Premium Model (RPM) (2)	10.72%	10.70%
3.	Capital Asset Pricing Model (CAPM) (3)	10.82%	10.42%
4.	Market Models Applied to Comparable Risk, Non-Price Regulated Companies (4)	10.89%	10.76%
5.	Indicated Common Equity Cost Rate before Adjustment for Unique Risk	10.42% - 10.89%	10.19% - 10.76%
6.	Size Risk Adjustment (5)	1.00%	0.85%
7.	Performance Factor Adjustment (6)	0.05%	0.05%
8.	Indicated Common Equity Cost Rate after Adjustment	11.47% - 11.94%	11.09% - 11.66%
9.	Recommended Common Equity Cost Rate	11.65%	11.65%

Notes:
(1) From page 3 of this Schedule.
(2) From page 26 of this Schedule.
(3) From page 37 of this Schedule.
(4) From page 44 of this Schedule.
(5) Adjustment to reflect Valley Energy, Inc.'s, Citizens' Electric Company, and Wellsboro Electric Company's greater business risk due to their smaller sizes relative to the Utility Proxy Groups as detailed in Mr. D'Ascendis' Direct Testimony.
(6) Performance factor adjustment as explained in the Companies' Direct Testimony.

Valley Energy, Inc. / Citizens' Electric Company of Lewisburg, PA / Wellsboro Electric Company
Indicated Common Equity Cost Rate Using the Discounted Cash Flow Model for the
Proxy Group of Eight Natural Gas Distribution Companies and Proxy Group of Fourteen Electric Companies

	[1]	[2]	[3]	[4]	[5]	[6]	[7]	
Proxy Group of Eight Natural Gas Distribution Companies	Average Dividend Yield (1)	Value Line Projected Five Year Growth in EPS (2)	Zack's Five Year Projected Growth Rate in EPS	S&P Capital IQ Projected Five Year Growth in EPS	Average Projected Five Year Growth in EPS (3)	Adjusted Dividend Yield (4)	Indicated Common Equity Cost Rate (5)	
Atmos Energy Corporation	2.24 %	7.00 %	7.20 %	7.08 %	7.09 %	2.32 %	9.41 %	
Chesapeake Utilities Corporation	2.21	8.00	NA	8.33	8.16	2.30	10.46	
New Jersey Resources Corporation	3.90	5.00	NA	7.90	6.45	4.03	10.48	
NiSource Inc.	2.84	9.50	7.90	7.96	8.45	2.96	11.41	
Northwest Natural Holding Company	4.74	6.50	NA	5.75	6.13	4.89	11.02	
ONE Gas, Inc.	3.59	4.50	5.60	5.84	5.31	3.69	9.00	
Southwest Gas Holdings, Inc.	3.39	10.00	10.50	10.74	10.41	3.57	13.98	(6)
Spire Inc.	4.22	4.50	6.50	8.08	6.36	4.35	10.71	
						Average	10.35 %	
		NA= Not Available				Median	10.48 %	
						Average of Mean and Median	10.42 %	

	[1]	[2]	[3]	[4]	[5]	[6]	[7]	
Proxy Group of Fourteen Electric Companies	Average Dividend Yield (1)	Value Line Projected Five Year Growth in EPS (2)	Zack's Five Year Projected Growth Rate in EPS	S&P Capital IQ Projected Five Year Growth in EPS	Average Projected Five Year Growth in EPS (3)	Adjusted Dividend Yield (4)	Indicated Common Equity Cost Rate (5)	
Alliant Energy Corporation	3.31 %	6.00 %	6.60 %	6.67 %	6.42 %	3.42 %	9.84 %	
American Electric Power Corporation	3.58	6.50	6.40	6.82	6.57	3.70	10.27	
Ameren Corporation	2.94	6.50	7.90	7.60	7.33	3.05	10.38	
Duke Energy Corporation	3.63	6.00	6.30	6.36	6.22	3.74	9.96	
Edison International	6.17	6.50	7.00	8.90	7.47	6.40	13.87	(6)
Entergy Corporation	2.90	3.00	9.50	8.88	7.13	3.00	10.13	
Evergy, Inc.	3.95	7.50	5.70	5.70	6.30	4.07	10.37	
FirstEnergy Corporation	4.32	4.50	6.40	6.52	5.81	4.45	10.26	
IDACORP, Inc.	2.97	6.00	8.10	8.55	7.55	3.08	10.63	
OGE Energy Corporation	3.80	6.50	6.30	6.74	6.51	3.92	10.43	
Pinnacle West Capital Corporation	3.93	5.00	2.10	5.25	4.12	4.01	8.13	
Portland General Electric Company	5.07	6.50	3.30	4.95	4.92	5.19	10.11	
Southern Company	3.28	6.50	6.80	6.97	6.76	3.39	10.15	
Xcel Energy, Inc.	3.30	7.00	7.50	7.95	7.48	3.42	10.90	
						Average	10.12 %	
		NA= Not Available				Median	10.26 %	
						Average of Mean and Median	10.19 %	

Notes:

(1) Indicated dividend at 7/18/2025 divided by the average closing price of the last 60 trading days ending 7/18/2025 for each company.
(2) From pages 4 through 25 of this Schedule.
(3) Average of columns 2 through 4 excluding negative growth rates.
(4) This reflects a growth rate component equal to one-half the conclusion of growth rate (from column 5) x column 1 to reflect the periodic payment of dividends (Gordon Model) as opposed to the continuous payment. Thus, for Atmos Energy Corporation, 2.24% x (1+(1/2 x 7.09%)) = 2.32%.
(5) Column 5 + Column 6.
(6) Results were excluded from the final average and median as they were more than two standard deviations from the proxy group's mean.

Source of Information:
Value Line Investment Survey
www.zacks.com Downloaded on 7/18/2025
S&P Capital IQ

ATMOS ENERGY CORP. NYSE-ATO

RECENT PRICE 155.23 | P/E RATIO 20.9 (Trailing: 21.6 Median: 20.0) | RELATIVE P/E RATIO 1.17 | DIV'D YLD 2.3% | VALUE LINE

TIMELINESS 3 Raised 1/17/25
SAFETY 1 Raised 6/6/14
TECHNICAL 3 Raised 5/9/25
BETA .75 (1.00 = Market)

18-Month Target Price Range
Low-High **Midpoint (% to Mid)**
$136-$194 $165 (5%)

2028-30 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	185	(+20%)	*7%*
Low	150	(-5%)	*2%*

Institutional Decisions

	2Q2024	3Q2024	4Q2024
to Buy	342	357	421
to Sell	311	315	294
Hld's(000)	144146	162641	171243

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
High:	58.2	64.8	82.0	93.6	100.8	115.2	121.1	105.3	123.0	125.3	152.6	167.5						
Low:	44.2	50.8	60.0	72.5	76.5	89.2	77.9	84.6	97.7	101.0	110.5	136.2						

LEGENDS
35.50 x Dividends p sh
Relative Price Strength
Options: Yes
Shaded area indicates recession

Target Price Range 2028 2029 2030

% TOT. RETURN 5/12/25

	THIS STOCK	VL ARITH.* INDEX
1 yr.	35.8	6.0
3 yr.	49.4	19.2
5 yr.	82.9	95.9

53.69	53.12	48.15	38.10	42.88	49.22	40.82	32.23	26.01	28.00	24.32	22.41	25.73	29.82	28.79	26.83	***28.05***	***28.15***
4.29	4.64	4.72	4.76	5.14	5.42	5.81	6.19	6.62	7.24	7.57	8.03	8.64	9.30	10.04	11.03	***11.80***	***12.45***
1.97	2.16	2.26	2.10	2.50	2.96	3.09	3.38	3.60	4.00	4.35	4.72	5.12	5.60	6.10	6.83	***7.30***	***7.70***
1.32	1.34	1.36	1.38	1.40	1.48	1.56	1.68	1.80	1.94	2.10	2.30	2.50	2.72	2.96	3.22	***3.48***	***3.68***
5.51	6.02	6.90	8.12	9.32	8.32	9.61	10.46	10.72	13.19	14.19	15.38	14.87	17.35	18.90	18.92	***22.85***	***22.75***
23.52	24.16	24.98	26.14	28.47	30.74	31.48	33.32	36.74	42.87	48.18	53.95	59.71	66.85	73.20	78.31	***84.25***	***86.25***
92.55	90.16	90.30	90.24	90.64	100.39	101.48	103.93	106.10	111.27	119.34	125.88	132.42	140.90	148.49	155.26	***162.00***	***167.00***
12.5	13.2	14.4	15.9	15.9	16.1	17.5	20.8	22.0	21.7	23.2	22.3	18.8	19.3	18.7	17.3		
.83	.84	.90	1.01	.89	.85	.88	1.09	1.11	1.17	1.24	1.15	1.02	1.12	1.08	.90		
5.3%	4.7%	4.2%	4.1%	3.5%	3.1%	2.9%	2.4%	2.3%	2.2%	2.1%	2.2%	2.6%	2.5%	2.6%	2.7%		

Bold figures are Value Line estimates

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Revenues per sh [A]	*34.05*
"Cash Flow" per sh	*14.75*
Earnings per sh [AB]	*9.35*
Div'ds Decl'd per sh [C■]	*4.45*
Cap'l Spending per sh	*21.60*
Book Value per sh	*97.30*
Common Shs Outst'g [D]	*185.00*
Avg Ann'l P/E Ratio	*18.0*
Relative P/E Ratio	*1.00*
Avg Ann'l Div'd Yield	*2.7%*

4142.1	3349.9	2759.7	3115.5	2901.8	2821.1	3407.5	4201.7	4275.4	4165.2	***4540***	***4700***
315.1	350.1	382.7	444.3	511.4	580.5	665.6	774.4	885.9	1042.9	***1170***	***1270***
38.3%	36.4%	36.6%	27.0%	21.4%	19.5%	18.8%	9.1%	11.4%	15.6%	***19.0%***	***19.5%***
7.6%	10.5%	13.9%	14.3%	17.6%	20.6%	19.5%	18.4%	20.7%	25.0%	***25.8%***	***27.0%***
43.5%	38.7%	44.0%	34.3%	38.0%	40.0%	38.4%	37.9%	37.9%	39.3%	***40.0%***	***40.0%***
56.5%	61.3%	56.0%	65.7%	62.0%	60.0%	61.6%	62.1%	62.1%	60.7%	***60.0%***	***60.0%***
5650.2	5651.8	6965.7	7263.6	9279.7	11323	12837	15180	17509	20018	***22750***	***24000***
7430.6	8280.5	9259.2	10371	11788	13355	15064	17240	19607	22204	***25000***	***26400***
6.6%	7.2%	6.4%	6.9%	6.1%	5.5%	5.5%	5.4%	5.5%	5.7%	***6.5%***	***6.5%***
9.9%	10.1%	9.8%	9.3%	8.9%	8.5%	8.4%	8.2%	8.1%	8.6%	***8.5%***	***9.0%***
9.9%	10.1%	9.8%	9.3%	8.9%	8.5%	8.4%	8.2%	8.1%	8.6%	***8.5%***	***9.0%***
4.9%	5.1%	4.9%	4.8%	4.6%	4.4%	4.3%	4.2%	4.2%	4.5%	***4.5%***	***4.5%***
51%	50%	50%	48%	48%	49%	49%	49%	49%	47%	***48%***	***48%***

Revenues ($mill) [A]	*6300*
Net Profit ($mill)	*1730*
Income Tax Rate	*25.0%*
Net Profit Margin	*27.5%*
Long-Term Debt Ratio	*40.0%*
Common Equity Ratio	*60.0%*
Total Capital ($mill)	*30000*
Net Plant ($mill)	*32000*
Return on Total Cap'l	*7.0%*
Return on Shr. Equity	*9.5%*
Return on Com Equity	*9.5%*
Retained to Com Eq	*5.0%*
All Div'ds to Net Prof	*48%*

CAPITAL STRUCTURE as of 3/31/25
Total Debt $8506.4 mill. **Due in 5 Yrs** $1170.0 mill.
LT Debt $8486.3 mill. **LT Interest** $190.0 mill.
(LT interest earned: 7.5x; total interest coverage: 7.5x)
Leases, Uncapitalized Annual rentals $43.2 mill.

Pfd Stock None

Pension Assets-9/24 $595.2 mill.
Oblig. $470.9 mill.
Common Stock 158,836,864 shs.
as of 5/2/25

MARKET CAP: $24.7 billion (Large Cap)

CURRENT POSITION ($MILL.)	2023	2024	3/31/25
Cash Assets	15.4	307.3	543.5
Other	870.4	825.0	1047.8
Current Assets	885.8	1132.3	1591.3
Accts Payable	336.1	445.4	445.2
Debt Due	253.4	9.9	20.1
Other	763.1	750.6	733.2
Current Liab.	1352.6	1205.9	1198.5
Fix. Chg. Cov.	1059%	914%	935%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '22-'24 to '28-'30
Revenues	-4.0%	2.0%	*3.0%*
"Cash Flow"	7.0%	7.0%	*6.5%*
Earnings	9.5%	9.0%	*7.0%*
Dividends	7.5%	9.0%	*7.0%*
Book Value	10.0%	11.5%	*5.0%*

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.) [A] Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2022	1012.8	1649.8	816.4	722.7	4201.7
2023	1484.0	1541.0	662.7	587.7	4275.4
2024	1158.5	1647.2	701.5	658.0	4165.2
2025	1176.0	1950.5	*740*	*673.5*	*4540*
2026	*1210*	*2030*	*760*	*700*	*4700*

Fiscal Year Ends	EARNINGS PER SHARE [A B E] Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2022	1.86	2.37	.92	.51	5.60
2023	1.91	2.48	.94	.80	6.10
2024	2.08	2.85	1.08	.86	6.83
2025	2.23	3.03	*1.14*	*.90*	*7.30*
2026	*2.34*	*3.14*	*1.22*	*1.00*	*7.70*

Calendar	QUARTERLY DIVIDENDS PAID [C■] Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	.625	.625	.625	.68	2.56
2022	.68	.68	.68	.74	2.78
2023	.74	.74	.74	.805	3.03
2024	.805	.805	.805	.87	3.29
2025	.87	.87			

BUSINESS: Atmos Energy Corporation is engaged primarily in the distribution and sale of natural gas to over 3.3 million customers through six regulated natural gas utility operations: Louisiana Division, West Texas Division, Mid-Tex Division, Mississippi Division, Colorado-Kansas Division, and Kentucky/Mid-States Division. Gas sales breakdown for fiscal 2024: 68.8%, residential; 27.1%, commercial; 2.7%, industrial; and 1.4% other. The company sold Atmos Energy Marketing, 1/17. Officers and directors own approximately .5% of common stock (12/24 Proxy). President and Chief Executive Officer: Kevin Akers. Incorporated: Texas. Address: Three Lincoln Centre, Suite 1800, 5430 LBJ Freeway, Dallas, Texas 75240. Telephone: 972-934-9227. Internet: www.atmosenergy.com.

Atmos Energy is having a decent year thus far. Earnings per share through the first half of fiscal 2025 (ended March 31st) increased 6.7%, to $5.26, relative to the $4.93 figure that was registered for the fiscal 2024 period. One supporting factor was the distribution unit, aided partially by rate adjustments and benefits of residential customer growth (both happening mainly in the Mid-Tex Division). Moreover, the pipeline and storage segment was helped, among other things, by the Gas Reliability Infrastructure Program filing approved in May 2024 and the System Safety and Integrity Rider filing approved in November 2024. But the company's results were hurt, to some degree, by a rise in bad-debt expense, depreciation, and property taxes. Nonetheless, it appears that, for the full year, the bottom line will end up around $7.30 per share. That would indicate a 7% advance from fiscal 2024's $6.83 tally. Concerning the following fiscal year, per-share profits stand to grow another 5% or so, to $7.70, as operating margins widen further.

There has been activity on the rate-filing front. During the first six months, Atmos managed to complete some regulatory proceedings leading to a $152.6 million boost in annual operating income. What's more, there were ratemaking initiatives in progress at the conclusion of March seeking $224.7 million of annual operating income. Of course, there are no guarantees that the company will receive everything it requests.

Good things seem to be in store out to 2028-2030. Atmos ranks as one of the nation's biggest natural gas-only distributors, with over three million customers across several states, including Texas, Louisiana, and Mississippi. Also, we believe that the pipeline and storage business has promising overall expansion opportunities, since it operates in one of the most-active drilling regions in the world. The solid balance sheet is another positive.

The equity's long-term total return prospects look rather uninspiring. The dividend yield does not impress versus the average of *Value Line's* Natural Gas Utility Industry. Also, 3- to 5-year capital appreciation potential lacks appeal, given recent stock-price strength.

Frederick L. Harris, III *May 23, 2025*

(A) Fiscal year ends Sept. 30th. **(B)** Diluted shrs. Excl. nonrec. gains (loss): '10, 5¢; '11, (1¢); '18, $1.43; '20, 17¢. Excludes discontinued operations: '11, 10¢; '12, 27¢; '13, 14¢; '17, 13¢. Next earnings report due early Aug. **(C)** Dividends historically paid in early March, June, Sept., and Dec. ■ Div. reinvestment plan. Direct stock purchase plan avail. **(D)** In millions. **(E)** Qtrs may not add due to change in shrs outstanding.

Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	65
Earnings Predictability	100

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CHESAPEAKE UTIL. NYSE-CPK

RECENT PRICE **122.91** | P/E RATIO **21.6** (Trailing: 23.3 Median: 23.0) | RELATIVE P/E RATIO **1.21** | DIV'D YLD **2.3%** | **VALUE LINE**

TIMELINESS 3 Raised 3/21/25
SAFETY 2 New 6/5/15
TECHNICAL 1 Raised 5/23/25
BETA .75 (1.00 = Market)

18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$95-$148	$122 (0%)

2028-30 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	160	(+30%)	*9%*
Low	120	(Nil)	*2%*

Institutional Decisions

	2Q2024	3Q2024	4Q2024
to Buy	121	139	151
to Sell	117	116	127
Hld's(000)	18673	23010	23287

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
High:	52.7	61.1	70.0	86.4	93.4	98.6	111.4	146.1	146.3	132.9	134.2	136.7						
Low:	37.5	44.4	52.3	63.0	66.4	77.6	69.5	99.6	105.8	83.8	98.3	115.1						

Target Price Range 2028 | 2029 | 2030

% TOT. RETURN 5/12/25

	THIS STOCK	VL ARITH.* INDEX
1 yr.	12.3	6.0
3 yr.	2.8	19.2
5 yr.	60.6	95.9

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	© VALUE LINE PUB. LLC	28-30
	19.07	29.93	29.13	27.26	30.73	34.19	30.07	30.60	37.79	43.81	29.24	27.96	32.28	38.37	30.16	34.38	*37.90*	*42.50*	Revenues per sh	*65.40*
	2.15	3.50	3.69	3.95	4.35	4.73	5.05	5.16	5.42	6.47	6.50	7.37	8.28	8.87	6.87	8.05	*9.40*	*10.20*	"Cash Flow" per sh	*14.05*
	1.43	1.82	1.91	1.99	2.26	2.47	2.68	2.86	2.68	3.45	3.72	4.21	4.73	4.97	4.73	5.26	*5.70*	*6.10*	Earnings per sh [A]	*8.00*
	.83	.87	.91	.96	1.01	1.07	1.12	1.19	1.26	1.39	1.55	1.69	1.84	2.03	2.25	2.46	*2.65*	*2.82*	Div'ds Decl'd per sh [B]■	*3.40*
	1.89	3.18	3.28	5.00	6.72	6.66	9.47	10.42	10.73	16.47	11.26	9.48	10.59	7.23	8.48	15.52	*15.00*	*15.25*	Cap'l Spending per sh	*15.35*
	14.89	15.84	16.78	17.82	19.28	20.59	23.45	27.36	29.75	31.65	34.23	39.92	43.85	46.94	56.04	60.71	*64.05*	*69.00*	Book Value per sh	*77.50*
	14.09	14.29	14.35	14.40	14.46	14.59	15.27	16.30	16.34	16.38	16.40	17.46	17.66	17.74	22.24	22.90	*24.00*	*24.00*	Common Shs Outst'g [C]	*26.00*
	14.2	12.2	14.2	14.8	15.6	17.7	19.1	21.8	27.8	22.9	24.7	21.6	25.6	25.8	24.3	21.5	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	*17.5*
	.95	.78	.89	.94	.88	.93	.96	1.14	1.40	1.24	1.32	1.11	1.38	1.49	1.36	1.13			Relative P/E Ratio	*.95*
	4.1%	3.9%	3.4%	3.3%	2.9%	2.4%	2.2%	1.9%	1.7%	1.8%	1.7%	1.9%	1.5%	1.6%	2.0%	2.2%			Avg Ann'l Div'd Yield	*2.4%*
							459.2	498.9	617.6	717.5	479.6	488.2	570.0	680.7	670.6	787.2	*910*	*1020*	Revenues ($mill)	*1700*
							40.2	44.7	43.8	56.6	61.1	70.6	83.5	88.4	87.2	118.6	*135*	*145*	Net Profit ($mill)	*215*
							39.5%	38.8%	39.5%	27.1%	25.6%	25.0%	25.9%	27.4%	24.4%	26.7%	*26.5%*	*27.0%*	Income Tax Rate	*29.0%*
							8.8%	9.0%	7.1%	7.9%	12.7%	14.5%	14.6%	13.0%	13.0%	15.1%	*14.8%*	*14.2%*	Net Profit Margin	*12.6%*
							29.4%	23.5%	28.9%	37.9%	43.9%	42.2%	41.5%	41.0%	48.8%	47.6%	*47.0%*	*47.0%*	Long-Term Debt Ratio	*48.0%*
							70.6%	76.5%	71.1%	62.1%	56.1%	57.8%	58.5%	59.0%	51.2%	52.4%	*53.0%*	*53.0%*	Common Equity Ratio	*52.0%*
							507.5	583.0	683.7	834.5	1001.7	1205.6	1324.0	1411.2	2433.2	2651.9	*2900*	*3125*	Total Capital ($mill)	*3875*
							855.0	986.7	1126.0	1384.0	1463.8	1601.2	1744.9	1810.5	2456.4	2735.9	*3000*	*3250*	Net Plant ($mill)	*4050*
							8.9%	8.6%	7.3%	7.8%	7.2%	6.8%	7.1%	7.1%	4.3%	5.8%	*6.0%*	*6.0%*	Return on Total Cap'l	*7.0%*
							11.2%	10.0%	9.0%	10.9%	10.9%	10.1%	10.8%	10.6%	7.0%	8.5%	*9.0%*	*9.0%*	Return on Shr. Equity	*10.5%*
							11.2%	10.0%	9.0%	10.9%	10.9%	10.1%	10.8%	10.6%	7.0%	8.5%	*9.0%*	*9.0%*	Return on Com Equity	*10.5%*
							6.8%	6.1%	4.9%	6.7%	6.5%	6.2%	6.7%	6.4%	3.8%	4.6%	*4.5%*	*4.5%*	Retained to Com Eq	*6.5%*
							40%	39%	45%	39%	40%	38%	38%	40%	46%	46%	*47%*	*47%*	All Div'ds to Net Prof	*41%*

CAPITAL STRUCTURE as of 3/31/25
Total Debt $1500.9 mill. **Due in 5 Yrs** $780.0 mill.
LT Debt $1260.0 mill. **LT Interest** $68.0 mill.
(LT interest earned: 3.4x; total interest coverage: 3.4x) (47% of Cap'l)
Leases, Uncapitalized Annual rentals $2.6 mill.
Pfd Stock None
Pension Assets-12/24 $49.1 mill.
Oblig. $47.0 mill.
Common Stock 23,327,358 shs.
as of 5/2/25

MARKET CAP: $2.9 billion (Mid Cap)

CURRENT POSITION ($MILL.)	2023	2024	3/31/25
Cash Assets	4.9	7.9	.7
Other	180.8	196.4	198.9
Current Assets	185.7	204.3	199.6
Accts Payable	77.5	78.3	76.6
Debt Due	198.4	222.0	240.9
Other	110.5	119.1	116.2
Current Liab.	386.4	419.4	433.7
Fix. Chg. Cov.	514%	393%	400%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '22-'24 to '28-'30
Revenues	1.0%	-1.5%	*11.5%*
"Cash Flow"	6.0%	5.5%	*10.0%*
Earnings	8.5%	8.5%	*8.0%*
Dividends	8.5%	10.0%	*7.0%*
Book Value	11.0%	11.5%	*6.0%*

Calendar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2022	222.9	139.5	131.1	187.2	680.7
2023	218.1	135.6	131.5	185.4	670.6
2024	245.7	166.3	160.1	215.1	787.2
2025	298.7	*187*	*183*	*241.3*	*910*
2026	*330*	*215*	*210*	*265*	*1020*

Calendar	EARNINGS PER SHARE [A] Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2022	2.08	.88	.54	1.47	4.97
2023	2.04	.90	.53	1.26	4.73
2024	2.07	.82	.78	1.60	5.26
2025	2.21	*.88*	*.84*	*1.77*	*5.70*
2026	*2.30*	*.99*	*.93*	*1.88*	*6.10*

Calendar	QUARTERLY DIVIDENDS PAID [B]■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	.44	.44	.48	.48	1.84
2022	.48	.48	.535	.535	2.03
2023	.535	.535	.59	.59	2.25
2024	.59	.59	.64	.64	2.46
2025	.64	.64	.685		

BUSINESS: Chesapeake Utilities Corporation consists of two main units. The Regulated Energy segment distributes natural gas in Delaware, Maryland, and Florida; distributes electricity in Florida; and transmits natural gas on the Delmarva Peninsula and in Florida. The Unregulated Energy operation wholesales and distributes propane; markets natural gas; and provides other unregulated energy services, including midstream services in Ohio. Revenue breakdown for 2024: Regulated Energy, 74.1%; Unregulated Energy, 29.0%; Other, d3.1%. Officers and directors own 1.5% of common stock; BlackRock, 16.1% (3/25 Proxy). Chairman and CEO: Jeffry Householder. Inc.: DE. Address: 500 Energy Lane, Dover, DE 19901. Tel.: (302) 734-6799. Internet: www.chpk.com.

Chesapeake Utilities Corporation began 2025 on the right foot. Indeed, first-quarter earnings per share increased almost 7%, to $2.21, compared to the $2.07 figure that was posted last year. One supporting factor was higher customer consumption resulting from cooler temperatures, mainly across the Mid-Atlantic and Ohio service areas. Another plus was a rise in demand for virtual pipeline services. Other positives included internal growth in the natural gas distribution businesses and contributions from regulated infrastructure programs. So, at this juncture, it appears that full-year profits will end up in the vicinity of $5.70 a share. That would show a roughly 8% advance from 2024's $5.26 tally. Regarding 2026, the company's bottom line may grow at a similar percentage rate, to $6.10 a share, assuming additional expansion of operating margins.

This year's capital expenditures are anticipated to lie between $325 million and $375 million. The bulk of the funds are being deployed to the Regulated Energy division, with an emphasis on the natural gas distribution and transmission segments. Moreover, Chesapeake looks for total capital spending to be in the range of $1.5 billion to $1.8 billion for the five-year period between 2024 and 2028. All told, we believe these objectives are achievable, assuming that corporate finances remain in healthy condition, of course.

The quarterly common stock dividend was raised by 7%, to $0.685 per share. That was made possible, no doubt, by the company's solid capital position. Furthermore, our 3- to 5-year projections indicate that additional steady increases in the distribution will probably take place. The payout ratio over that horizon ought to be in the neighborhood of 40%, which is quite manageable.

The stock is not a standout selection at the moment. Its dividend yield is not exciting when measured against those of other Natural Gas Utility equities tracked by *Value Line*. Moreover, capital gains potential out to 2028-2030 does not impress. That's because the recent quotation is already within our Target Price Range. Meanwhile, these shares are ranked just 3 (Average) for Timeliness.

Frederick L. Harris, III *May 23, 2025*

Company's Financial Strength	A
Stock's Price Stability	90
Price Growth Persistence	80
Earnings Predictability	100

(A) Diluted shrs. Excludes nonrecurring gains: '15, 6¢; '17, 87¢; '22, 8¢. Excludes discontinued operations: '19, 24¢; '20, 5¢. Next earnings report due early Aug. Quarters for '24 don't add up to total due to rounding. **(B)** Dividends historically paid in early January, April, July, and October. ■ Dividend reinvestment plan. Direct stock purchase plan available. **(C)** In millions, adjusted for split.

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NEW JERSEY RES. NYSE-NJR

RECENT PRICE **46.29** | P/E RATIO **14.9** (Trailing: 12.0 Median: 17.0) | RELATIVE P/E RATIO **0.83** | DIV'D YLD **3.9%** | **VALUE LINE**

TIMELINESS 4 Raised 3/29/24
SAFETY 2 Lowered 4/17/20
TECHNICAL 1 Raised 5/23/25
BETA .85 (1.00 = Market)

18-Month Target Price Range

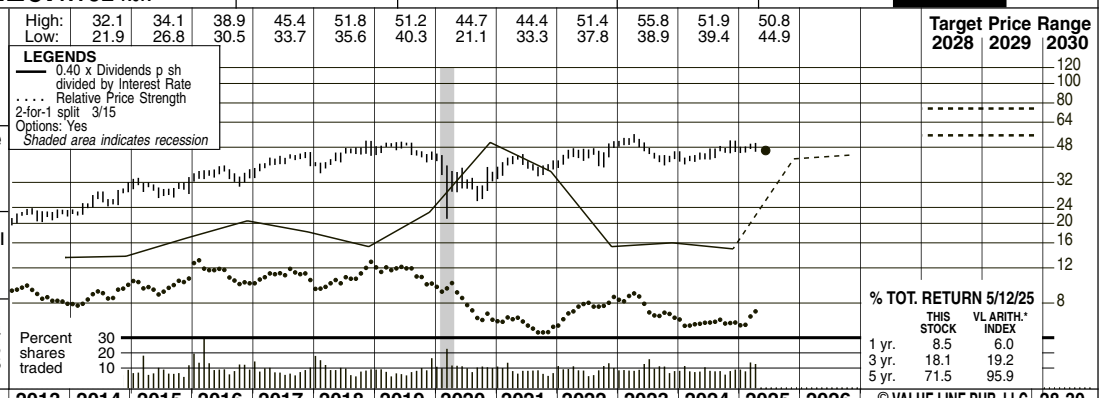
Low-High	Midpoint (% to Mid)
$42-$67	$55 (20%)

2028-30 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	75	(+60%)	*16%*
Low	55	(+20%)	*8%*

Institutional Decisions

	2Q2024	3Q2024	4Q2024
to Buy	167	196	215
to Sell	139	134	135
Hld's(000)	71950	88596	91465



2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	© VALUE LINE PUB. LLC	28-30
31.17	32.05	36.30	27.08	38.38	44.40	32.09	21.90	26.28	33.24	29.01	20.39	22.71	30.19	20.12	18.06	*19.45*	*18.85*	Revenues per sh A	*21.45*
1.58	1.63	1.70	1.86	1.93	2.73	2.52	2.46	2.68	3.72	2.99	3.30	3.36	3.84	4.28	4.59	*5.10*	*5.15*	"Cash Flow" per sh	*6.05*
1.20	1.23	1.29	1.36	1.37	2.08	1.78	1.61	1.73	2.72	1.96	2.07	2.16	2.50	2.71	2.95	*3.30*	*3.25*	Earnings per sh B	*3.90*
.62	.68	.72	.77	.81	.86	.93	.98	1.04	1.11	1.19	1.27	1.36	1.45	1.56	1.71	*1.80*	*1.95*	Div'ds Decl'd per sh C■	*2.20*
.90	1.05	1.13	1.26	1.33	1.52	3.76	4.15	3.80	4.39	5.83	4.65	5.42	5.81	5.13	5.26	*5.50*	*5.75*	Cap'l Spending per sh	*6.50*
8.29	8.81	9.36	9.80	10.65	11.48	12.99	13.58	14.33	16.18	17.37	19.26	17.18	18.88	20.40	22.12	*24.75*	*25.35*	Book Value per sh D	*27.65*
83.17	82.35	82.89	83.05	83.32	84.20	85.19	85.88	86.32	87.69	89.34	95.80	94.95	96.25	97.58	99.46	*101.00*	*102.00*	Common Shs Outst'g E	*105.00*
14.9	15.0	16.8	16.8	16.0	11.7	16.6	21.3	22.4	15.6	24.3	17.7	17.5	17.0	17.6	14.9	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	*17.0*
.99	.95	1.05	1.07	.90	.62	.84	1.12	1.13	.84	1.29	.91	.95	.98	.98	.77			Relative P/E Ratio	*.95*
3.5%	3.7%	3.3%	3.4%	3.7%	3.5%	3.1%	2.9%	2.7%	2.6%	2.5%	3.5%	3.6%	3.4%	3.3%	3.9%			Avg Ann'l Div'd Yield	*3.3%*
						2734.0	1880.9	2268.6	2915.1	2592.0	1953.7	2156.6	2906.0	1963.0	1796.5	*1965*	*1925*	Revenues ($mill) A	*2250*
						153.7	138.1	149.4	240.5	175.0	196.2	207.7	240.3	264.7	290.8	*335*	*330*	Net Profit ($mill)	*410*
						26.3%	15.5%	17.2%	--	--	--	10.3%	22.0%	15.9%	23.0%	*21.5%*	*22.0%*	Income Tax Rate	*22.0%*
						5.6%	7.3%	6.6%	8.2%	6.7%	10.0%	9.6%	8.3%	13.5%	16.2%	*17.0%*	*17.2%*	Net Profit Margin	*18.2%*
						43.2%	47.7%	44.6%	45.4%	49.8%	55.1%	57.0%	57.8%	58.2%	56.7%	*55.0%*	*55.0%*	Long-Term Debt Ratio	*55.0%*
						56.8%	52.3%	55.4%	54.6%	50.2%	44.9%	43.0%	42.2%	41.8%	43.3%	*45.0%*	*45.0%*	Common Equity Ratio	*45.0%*
						1950.6	2230.1	2233.7	2599.6	3088.9	4104.2	3793.0	4302.6	4758.8	5079.9	*5550*	*5750*	Total Capital ($mill)	*6450*
						2128.3	2407.7	2609.7	2651.0	3041.2	3983.0	4213.5	4649.9	5022.1	5403.2	*5650*	*5900*	Net Plant ($mill)	*6800*
						8.6%	6.9%	7.7%	10.1%	6.4%	5.6%	6.5%	6.8%	5.5%	5.7%	*6.0%*	*6.0%*	Return on Total Cap'l	*6.5%*
						13.9%	11.8%	12.1%	16.9%	11.3%	10.6%	12.7%	13.2%	13.3%	13.2%	*13.5%*	*13.0%*	Return on Shr. Equity	*14.0%*
						13.9%	11.8%	12.1%	16.9%	11.3%	10.6%	12.7%	13.2%	13.3%	13.2%	*13.5%*	*13.0%*	Return on Com Equity	*14.0%*
						7.0%	4.8%	5.0%	10.2%	4.6%	4.3%	5.6%	6.2%	5.7%	5.7%	*6.0%*	*5.0%*	Retained to Com Eq	*6.0%*
						50%	60%	59%	40%	59%	60%	56%	53%	58%	58%	*55%*	*60%*	All Div'ds to Net Prof	*56%*

CAPITAL STRUCTURE as of 3/31/25
Total Debt $3243.6 mill. **Due in 5 Yrs** $660 mill.
LT Debt $2970.2 mill. **LT Interest** $130 mill.
Incl. $8.4 mill. capitalized leases.

Pension Assets-9/24 $641 mill.
Oblig. $624 mill.

Pfd Stock None

Common Stock 100,371,550 shs.
as of 5/2/25

MARKET CAP: $4.6 billion (Mid Cap)

CURRENT POSITION ($MILL.)	2023	2024	3/31/25
Cash Assets	1.0	1.0	83.7
Other	531.1	553.6	594.9
Current Assets	532.1	554.6	678.6
Accts Payable	203.1	169.2	121.6
Debt Due	368.3	480.8	273.4
Other	235.2	237.8	337.0
Current Liab.	806.6	887.8	732.0
Fix. Chg. Cov.	331%	480%	1000%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '22-'24 to '28-'30
Revenues	-4.5%	-5.0%	*2.5%*
"Cash Flow"	7.0%	6.5%	*5.0%*
Earnings	5.5%	5.0%	*5.0%*
Dividends	7.0%	7.0%	*5.0%*
Book Value	7.0%	5.0%	*4.5%*

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.) A Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2022	675.9	912.3	552.3	765.5	2906.0
2023	723.6	644.0	264.1	331.3	1963.0
2024	467.2	657.9	275.6	395.8	1796.5
2025	488.4	913.0	*280*	*283.6*	*1965*
2026	*480*	*750*	*350*	*345*	*1925*

Fiscal Year Ends	EARNINGS PER SHARE A B Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2022	.69	1.36	d.04	.49	2.50
2023	1.14	1.16	.10	.31	2.71
2024	.74	1.41	d.09	.89	2.95
2025	1.28	1.78	*Nil*	*.23*	*3.30*
2026	*1.10*	*1.65*	*.10*	*.40*	*3.25*

Calendar	QUARTERLY DIVIDENDS PAID C■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	.3325	.3325	.3325	.3625	1.36
2022	.3625	.3625	.3625	.3625	1.45
2023	.39	.39	.39	.39	1.56
2024	.42	.42	.42	.45	1.71
2025	.45	.45			

BUSINESS: New Jersey Resources Corp. is a holding company providing retail/wholesale energy svcs. to customers in NJ, and in states from the Gulf Coast to New England, and Canada. New Jersey Natural Gas had 583,000 cust. at 9/30/24. Fiscal 2024 volume: 158 bill. cu. ft. (16% interruptible, 41% residential, commercial & firm transportation, 43% other). N.J. Natural Energy subsidiary provides unregulated retail/wholesale natural gas and related energy svcs. 2024 dep. rate: 3.2%. Has 1,370 empls. Off./dir. own less than 1% of common; BlackRock, 17.3%; Vanguard, 11.9% (12/24 Proxy). CEO, President & Director: Steven D. Westhoven. Incorporated: New Jersey. Address: 1415 Wyckoff Road, Wall, NJ 07719. Telephone: 732-938-1480. Web: www.njresources.com.

New Jersey Resources reported strong financial and operational results in the second quarter of fiscal 2025. (Year ends September 30th.) Favorable winter conditions and effective execution across its business portfolio led to a significant outperformance of both our top- and bottom-line estimates. Revenues advanced 40%, to $913 million, while earnings per share jumped 26% to $1.78. Principally, the utility's operations benefited from new rates following a recent base rate case settlement. Too, a gain realized on the sale of the company's residential solar portfolio at Clean Energy Ventures added to the earnings outperformance. Although the macroeconomic environment reflected some volatility during the period, and the company had to contend with policy uncertainty in energy markets, we view this result as a strong business-as-usual performance, reflecting NJR's solid fundamental market approach.

We've raised our fiscal 2025 full-year targets, reflecting a strong first half. With the remaining two fiscal quarters consisting of the gas utility's low season, we have a measure of confidence in our full year top- and bottom-line targets of $1.965 billion and $3.30, respectively. The latter is near the high end of management's guidance range.

We expect fiscal 2026 results will be mostly flat. Thanks to a weather tailwind in fiscal 2025, the comparison may be challenging and we expect a soft reset, with both revenues and earnings coming in a bit lower, overall. Operationally, this would reflect the steady advance of NJR's core business verticals.

Long-term growth prospects are defined by several key factors. NJR maintains a solid financial position, with manageable leverage and a strong regional economy as its foundation. Much of the growth we envision is a result of capital spending already planned for the next two years, with infrastructure modernization, energy efficiency and renewable initiatives all representing avenues for expansion.

The stock offers a solid long-term return profile, bolstered by non-regulated businesses that add a measure of growth potential, compared to pure-play utilities.

Earl B. Humes *May 23, 2025*

(A) Fiscal year ends Sept. 30th.
(B) Diluted earnings. Qtly. revenues and egs. may not sum to total due to rounding and change in shares outstanding. Next earnings report due early August.
(C) Dividends historically paid in early Jan., April, July, and October. ■ Dividend reinvestment plan available.
(D) Includes regulatory assets in 2024: $612.6 million, $6.16/share.
(E) In millions, adjusted for 3/15 split.

Company's Financial Strength	A
Stock's Price Stability	85
Price Growth Persistence	40
Earnings Predictability	65

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NISOURCE INC. NYSE-NI

RECENT PRICE **38.32** | P/E RATIO **20.1** (Trailing: 20.4 Median: 21.0) | RELATIVE P/E RATIO **1.13** | DIV'D YLD **3.0%** | **VALUE LINE**

TIMELINESS 4 Lowered 5/2/25
SAFETY 2 Raised 2/23/24
TECHNICAL 1 Raised 5/16/25
BETA .85 (1.00 = Market)

18-Month Target Price Range

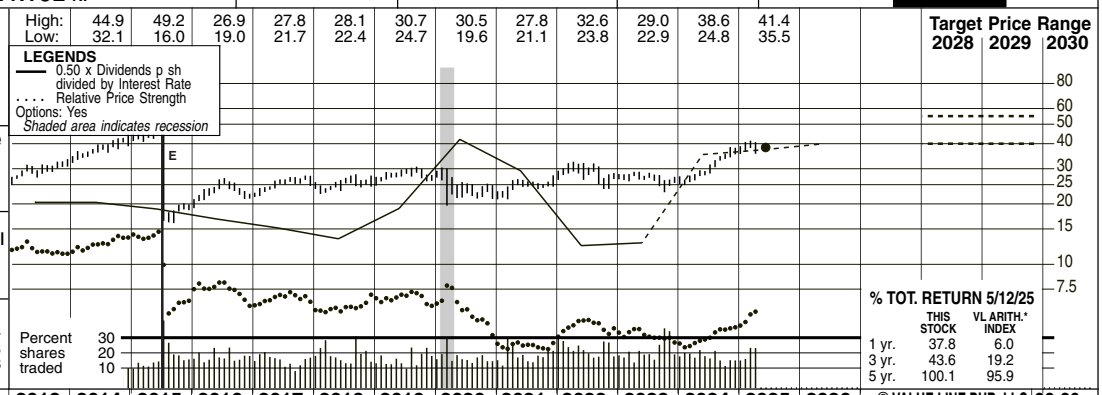
Low-High	Midpoint (% to Mid)
$28-$45	$37 (-5%)

2028-30 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	55	(+45%)	*12%*
Low	40	(+5%)	*5%*

Institutional Decisions

	2Q2024	3Q2024	4Q2024
to Buy	328	334	383
to Sell	249	286	288
Hld's(000)	439719	484273	493671



2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	© VALUE LINE PUB. LLC	28-30
24.02	22.99	21.33	16.31	18.04	20.47	14.58	13.90	14.46	13.74	13.63	11.95	12.09	14.20	12.31	11.61	*13.15*	*13.50*	Revenues per sh	*15.60*
2.96	3.19	2.98	3.13	3.41	3.60	2.27	2.71	2.07	2.86	3.17	3.15	3.26	3.56	3.63	3.97	*4.10*	*4.15*	"Cash Flow" per sh	*5.30*
.84	1.06	1.05	1.37	1.57	1.67	.63	1.00	.39	1.30	1.31	1.32	1.37	1.47	1.60	1.75	*1.90*	*2.00*	Earnings per sh [A]	*2.55*
.92	.92	.92	.94	.98	1.02	.83	.64	.70	.78	.80	.84	.88	.94	1.00	1.06	*1.12*	*1.20*	Div'd Decl'd per sh [B] ■	*1.44*
2.81	2.88	3.99	4.83	5.99	6.42	4.26	4.57	5.03	4.88	4.72	4.49	4.53	5.35	5.91	5.56	*5.50*	*6.00*	Cap'l Spending per sh	*7.00*
17.54	17.63	17.71	17.90	18.77	19.54	12.04	12.60	12.82	13.08	13.36	12.44	13.33	14.63	17.40	22.71	*23.30*	*23.25*	Book Value per sh [C]	*25.70*
276.79	279.30	282.18	310.28	313.68	316.04	319.11	323.16	337.02	372.36	382.14	391.76	405.30	412.14	447.38	469.82	*480.00*	*500.00*	Common Shs Outst'g [D]	*525.00*
14.3	15.3	19.4	17.9	18.9	22.7	37.3	23.2	NMF	19.3	21.3	18.7	18.0	19.6	16.8	17.5	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	*19.0*
.95	.97	1.22	1.14	1.06	1.19	1.88	1.22	NMF	1.04	1.13	.96	.97	1.13	.93	.97			Relative P/E Ratio	*1.05*
7.6%	5.7%	4.5%	3.8%	3.3%	2.7%	3.5%	2.8%	2.8%	3.1%	2.9%	3.4%	3.6%	3.3%	3.7%	3.5%			Avg Ann'l Div'd Yield	*3.0%*
4651.8	4492.5	4874.6	5114.5	5208.9	4681.7	4899.6	5850.6	5505.4	5455.1	*6300*	*6750*	Revenues ($mill)	*8200*
198.6	328.1	128.6	478.3	549.8	562.6	626.3	648.2	716.3	798.6	*915*	*1000*	Net Profit ($mill)	*1340*
41.6%	35.7%	71.0%	19.7%	17.0%	18.3%	15.7%	16.5%	17.8%	17.9%	*19.0%*	*19.0%*	Income Tax Rate	*19.0%*
--	--	--	--	--	--	--	--	3.0%	3.3%	*3.0%*	*3.0%*	AFUDC % to Net Profit	*3.0%*
60.7%	59.8%	63.5%	55.3%	56.8%	61.6%	56.9%	55.7%	57.2%	54.0%	*54.0%*	*55.0%*	Long-Term Debt Ratio	*55.0%*
39.3%	40.2%	36.5%	37.9%	36.9%	32.5%	33.5%	35.3%	40.3%	46.0%	*46.0%*	*45.0%*	Common Equity Ratio	*45.0%*
9792.0	10129	11832	12856	13843	14972	16131	17099	19325	24294	*24300*	*25850*	Total Capital ($mill)	*30000*
12112	13068	14360	15543	16912	16620	17882	19843	22275	27044	*27045*	*28970*	Net Plant ($mill)	*35325*
4.0%	5.0%	2.6%	5.1%	5.3%	5.0%	4.9%	3.8%	3.4%	3.5%	*4.0%*	*4.0%*	Return on Total Cap'l	*4.5%*
5.2%	8.1%	3.0%	8.3%	9.2%	9.8%	9.0%	8.6%	7.1%	*7.5%*	*8.0%*	*8.5%*	Return on Shr. Equity	*10.0%*
5.2%	8.1%	3.0%	9.6%	9.7%	10.4%	10.6%	10.7%	7.1%	7.5%	*8.0%*	*8.5%*	Return on Com Equity	*10.0%*
NMF	3.0%	NMF	4.0%	3.8%	3.8%	4.2%	3.6%	2.8%	3.0%	*3.5%*	*3.5%*	Retained to Com Eq	*4.5%*
NMF	63%	NMF	60%	64%	67%	64%	64%	63%	61%	*59%*	*60%*	All Div'ds to Net Prof	*57%*

CAPITAL STRUCTURE as of 3/31/25
Total Debt $14885 mill. **Due in 5 Yrs** $7435 mill.
LT Debt $12833 mill. **LT Interest** $550 mill.
(Interest cov. earned: 5.5x) (54% of Cap'l)

Leases, Uncapitalized Annual rentals $10.0 mill.
Pension Assets-12/23 $1.3 bill. **Oblig.** $1.3 bill.

Common Stock 470,702,914 shs.
as of 4/30/25

MARKET CAP: $18.0 billion (Large Cap)

CURRENT POSITION ($MILL.)	2023	2024	3/31/25
Cash Assets	2245.4	156.6	259.4
Other	2254.0	1923.6	1925.2
Current Assets	4499.4	2080.2	2184.6
Accts Payable	749.4	863.1	726.3
Debt Due	3072.4	1885.8	2052.0
Other	1443.3	1364.5	1463.6
Current Liab.	5265.1	4113.4	4241.9
Fix. Chg. Cov.	225%	280%	575%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '21-'23 to '28-'30
Revenues	-3.5%	-1.5%	*5.5%*
"Cash Flow"	1.0%	6.5%	*5.5%*
Earnings	1.0%	10.5%	*9.5%*
Dividends	--	6.0%	*4.5%*
Book Value	-2.0%	3.5%	*5.0%*

Calendar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2022	1873	1183	1089	1704	5850.6
2023	1966	1090	1027	1422	5505.4
2024	1706	1085	1076	1588	5455.1
2025	2183	*1255*	*1245*	*1617*	*6300*
2026	*2340*	*1245*	*1335*	*1730*	*6750*

Calendar	EARNINGS PER SHARE [A] Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2022	.75	.12	.10	.50	1.47
2023	.77	.11	.19	.53	1.60
2024	.85	.21	.20	.49	1.75
2025	.98	*.30*	*.25*	*.67*	*1.90*
2026	*1.05*	*.40*	*.30*	*.75*	*2.00*

Calendar	QUARTERLY DIVIDENDS PAID [B] ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	.22	.22	.22	.22	.88
2022	.235	.235	.235	.235	.94
2023	.25	.25	.25	.25	1.00
2024	.265	.265	.265	.265	1.06
2025	.28	.28			

BUSINESS: NiSource Inc. is a holding company for Northern Indiana Public Service Company (NIPSCO), which supplies electricity and gas to the northern third of Indiana. Customers: 492,690 electric in Indiana, 3.3 million gas in Indiana, Ohio, Pennsylvania, Kentucky, Virginia, Maryland, through its Columbia subsidiaries. Revenue breakdown, 2024: electrical, 34%; gas, 63%; other, 3%. Generating capacity, fossil feuls 56%; renewables, 44%. 2024 reported depreciation rates: 3.0% electric, 2.6% gas. Has 7,746 employees. Chairman: Richard L. Thompson. President & Chief Executive Officer: Lloyd Yates. Incorporated: Indiana. Address: 801 East 86th Avenue, Merrillville, Indiana 46410. Telephone: 877-647-5990. Internet: www.nisource.com.

NiSource posted a strong profit in the first quarter of 2025. Revenues expanded 28% to $2.2 billion, driven by regulated revenue growth and the recovery of significant capital investments made over the past few years. This pushed earnings to increase 15% to $0.98 per share, outpacing our target. Representing over half of our full-year earnings estimate, the result reflects stable utility performance across its gas and electric operations. Management noted the success of capturing efficiency gains from recent investments in technology, with artificial intelligence-optimized scheduling resulting in an impressive 60,000 hours improvement in measured labor productivity. Regulatory progress also supported results, with several successful rate cases contributing to the quarter's strong earnings.

The near-term outlook is somewhat mixed. Continued improvements may face pressure from uncertain regulatory proceedings. Particularly, a new proposal in Indiana is currently pending in settlement discussions. Too, a shifting landscape for renewables investment could affect the company's strategic priorities, especially as it seeks to decomission its legacy coal generation plants over the next few years. On a positive note, management has taken a proactive approach to tariff-related inflation risks by advancing its procurement for key infrastructure, however, broader economic developments may influence future costs. As a result, we are tentatively expecting mid- to high-single-digit earnings growth over the next few years.

NiSource is well positioned to benefit from long-term trends. Regional economic development, including the buildout of data centers and the potential for manufacturing reshoring, along with infrastructure modernization, provide promising tailwinds for energy demand and opportunities for investment. However, we are uncertain about the future for its ambitious clean-energy transition strategy, given the potential for policy shifts. Overall, the utility is likely to maintain a positive trajectory to late decade.

Despite the business' strengths, these untimely shares offer below-average capital appreciation potential to late decade, overall.

Earl B. Humes *May 23, 2025*

(A) Dil. EPS. Excl. gains (losses) on disc. ops.: '15, (30¢); '18, ($1.48). Next egs. report due early August. Qtl'y egs. may not sum to total due to rounding.
(B) Div'ds historically paid in mid-Feb., May, Aug., Nov. ■ Div'd reinv. avail.
(C) Incl. intang in '24: $1485.9 million, $3.16/sh.
(D) In mill.
(E) Spun off Columbia Pipeline Group (7/15)

Company's Financial Strength	A
Stock's Price Stability	95
Price Growth Persistence	30
Earnings Predictability	70

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N.W. NATURAL NYSE-NWN

RECENT PRICE **41.22** | P/E RATIO **13.7** (Trailing: 14.7 Median: 24.0) | RELATIVE P/E RATIO **0.77** | DIV'D YLD **4.8%** | **VALUE LINE**

TIMELINESS 3 Raised 3/28/25
SAFETY 2 Raised 2/23/24
TECHNICAL 2 Raised 5/23/25
BETA .80 (1.00 = Market)

18-Month Target Price Range

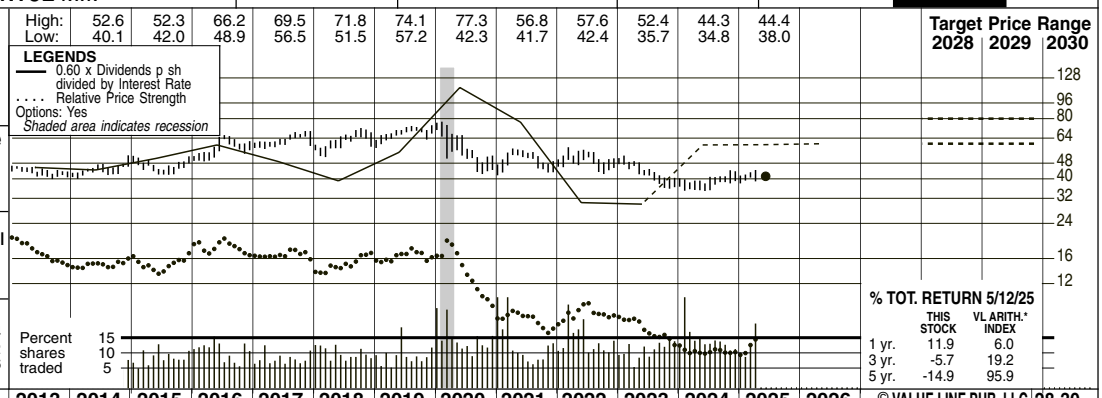
Low-High	Midpoint (% to Mid)
$30-$50	$40 (-5%)

2028-30 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	80	(+95%)	*21%*
Low	60	(+45%)	*13%*

Institutional Decisions

	2Q2024	3Q2024	4Q2024
to Buy	132	119	142
to Sell	104	118	96
Hld's(000)	29331	37328	37493



% TOT. RETURN 5/12/25

	THIS STOCK	VL ARITH.* INDEX
1 yr.	11.9	6.0
3 yr.	-5.7	19.2
5 yr.	-14.9	95.9

2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	© VALUE LINE PUB. LLC	28-30
38.17	30.56	31.72	27.14	28.02	27.64	26.39	23.61	26.52	24.45	24.49	25.29	27.64	29.20	31.82	28.67	*29.20*	*30.20*	Revenues per sh	*30.00*
5.20	5.18	5.00	4.94	5.04	5.05	4.91	4.93	1.04	5.28	5.15	5.69	6.17	5.71	5.83	5.68	*6.50*	*6.65*	"Cash Flow" per sh	*7.45*
2.83	2.73	2.39	2.22	2.24	2.16	1.96	2.12	d1.94	2.33	2.19	2.30	2.56	2.54	2.59	2.33	*3.00*	*3.10*	Earnings per sh A	*3.45*
1.60	1.68	1.75	1.79	1.83	1.85	1.86	1.87	1.88	1.89	1.90	1.91	1.92	1.93	1.94	1.95	*1.96*	*1.97*	Div'ds Decl'd per sh B■	*2.00*
5.09	9.35	3.76	4.91	5.13	4.40	4.37	4.87	7.43	7.43	7.95	9.18	9.49	9.53	8.70	8.80	*9.50*	*10.00*	Cap'l Spending per sh	*11.50*
24.88	26.08	26.70	27.23	27.77	28.12	28.47	29.71	25.85	26.41	28.42	29.05	30.04	33.09	34.12	34.45	*35.80*	*37.75*	Book Value per sh D	*40.40*
26.53	26.58	26.76	26.92	27.08	27.28	27.43	28.63	28.74	28.88	30.47	30.59	31.13	35.53	37.63	40.22	*43.00*	*45.00*	Common Shs Outst'g C	*50.00*
15.2	17.0	19.0	21.1	19.4	20.7	23.7	26.9	- -	26.6	30.9	25.0	19.5	19.6	16.6	16.6	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	*20.0*
1.01	1.08	1.19	1.34	1.09	1.09	1.19	1.41	- -	1.44	1.65	1.28	1.05	1.13	.92	.92			Relative P/E Ratio	*1.10*
3.7%	3.6%	3.9%	3.8%	4.2%	4.1%	4.0%	3.3%	3.0%	3.0%	2.8%	3.3%	3.8%	3.9%	4.5%	5.1%			Avg Ann'l Div'd Yield	*2.9%*
723.8	676.0	762.2	706.1	746.4	773.7	860.4	1037.4	1197.5	1153.0	*1255*	*1360*	Revenues ($mill)	*1500*
53.7	58.9	d55.6	67.3	65.3	70.3	78.7	86.3	93.9	90.6	*130*	*140*	Net Profit ($mill)	*175*
40.0%	40.9%	- -	26.4%	16.2%	23.1%	25.8%	25.2%	25.6%	25.6%	*25.0%*	*25.0%*	Income Tax Rate	*25.0%*
7.4%	8.7%	NMF	9.5%	8.8%	9.1%	9.1%	8.3%	7.8%	7.9%	*10.3%*	*10.3%*	Net Profit Margin	*11.5%*
42.5%	44.4%	47.9%	48.1%	48.2%	49.2%	52.8%	51.5%	52.6%	54.8%	*55.0%*	*55.0%*	Long-Term Debt Ratio	*55.0%*
57.5%	55.6%	52.1%	51.9%	51.8%	50.8%	47.2%	48.5%	47.4%	45.2%	*45.0%*	*45.0%*	Common Equity Ratio	*45.0%*
1357.7	1529.8	1426.0	1468.9	1672.0	1748.8	1979.7	2421.6	2709.3	3064.8	*3420*	*3775*	Total Capital ($mill)	*4485*
2182.7	2260.9	2255.0	2421.4	2438.9	2654.8	2871.4	3114.4	3358.1	3672.3	*3990*	*4300*	Net Plant ($mill)	*4930*
5.5%	5.1%	NMF	5.8%	5.2%	5.2%	5.1%	4.7%	4.9%	3.0%	*4.0%*	*3.5%*	Return on Total Cap'l	*4.0%*
6.9%	6.9%	NMF	8.8%	7.5%	7.9%	8.4%	7.3%	7.3%	*6.5%*	*8.5%*	*8.0%*	Return on Shr. Equity	*8.5%*
6.9%	6.9%	NMF	8.8%	7.5%	7.9%	8.4%	7.3%	7.3%	6.5%	*8.5%*	*8.0%*	Return on Com Equity	*8.5%*
.6%	.9%	NMF	2.1%	1.4%	1.7%	2.4%	2.0%	2.1%	.9%	*2.5%*	*2.5%*	Retained to Com Eq	*3.0%*
92%	87%	NMF	76%	82%	79%	71%	73%	72%	84%	*65%*	*64%*	All Div'ds to Net Prof	*58%*

CAPITAL STRUCTURE as of 3/31/25
Total Debt $2311 mill. **Due in 5 Yrs** $1100 mill.
LT Debt $2193 mill. **LT Interest** $80 mill.

(Total interest coverage: 6.5x)

Pension Assets-12/23 $284.1 mill.
Oblig. $405.6 mill.

Pfd Stock None

Common Stock 40,309,760 shares
as of 4/28/25

MARKET CAP $1.7 billion (Small Cap)

CURRENT POSITION ($MILL.)	2023	2024	3/31/25
Cash Assets	32.9	38.5	100.1
Other	568.5	519.3	439.8
Current Assets	601.4	557.8	539.9
Accts Payable	145.4	133.3	132.8
Debt Due	240.7	200.9	117.9
Other	310.8	314.8	263.3
Current Liab.	696.9	649.0	514.0
Fix. Chg. Cov.	240%	410%	665%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '21-'23 to '28-'30
Revenues	- -	3.5%	*4.5%*
"Cash Flow"	1.5%	9.5%	*5.0%*
Earnings	1.0%	25.0%	*6.5%*
Dividends	1.0%	.5%	*.5%*
Book Value	2.0%	3.5%	*4.0%*

Calendar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2022	350.3	195.0	116.8	375.3	1037.4
2023	462.4	237.9	141.5	355.7	1197.5
2024	433.5	211.7	136.9	370.9	1153.0
2025	494.3	*230*	*150*	*380.7*	*1255*
2026	*535*	*250*	*165*	*410*	*1360*

Calendar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2022	1.80	.05	d.56	1.36	2.54
2023	2.01	.03	d.65	1.21	2.59
2024	1.69	d.07	d.71	1.41	2.33
2025	2.28	*.05*	*d.60*	*1.27*	*3.00*
2026	*2.35*	*.05*	*d.65*	*1.35*	*3.10*

Calendar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	.48	.48	.48	.483	1.92
2022	.483	.483	.483	.485	1.93
2023	.485	.485	.485	.488	1.94
2024	.488	.488	.488	.49	1.95
2025	.49	.49			

BUSINESS: Northwest Natural Holding Co. distributes natural gas to more than 800,000 customers in Oregon (88% of customers) and in southwest Washington state. Principal cities served: Portland and Eugene, OR; Vancouver, WA. Company buys gas supply from Canadian and U.S. producers; has transportation rights on Northwest Pipeline system. Owns local underground storage. Gas margin breakdown: residential, 65%; commercial, 25%; industrial, 6%; other, 4%. Also operates water and wastewater services across six states. Employs 1,452. BlackRock Inc. owns 16.1% of shares; Vanguard, 10.8%; Off./Dir., .93% (4/25 proxy). CEO: Justin B. Palfreyman. Inc.: Oregon. Address: 220 NW 2nd Ave., Portland, OR 97209. Tel.: 503-226-4211. Internet: www.nwnatural.com.

Northwest Natural posted a strong start to what we expect will be a wide recovery performance in 2025. Driven by the resolution of regulatory lag in the last Oregon gas utility rate case, which was settled in October, earnings per share advanced a remarkable 35% to $2.28 in the March period. This long-awaited decision allowed for the recovery of significant capital investments made over the past few years, while seasonal strength in gas demand boosted the result. Organic customer growth across all utilities added up to roughly 2.2%, while the total count increased 9.6% thanks to acquisitions, including that of SiEnergy in January, which added 73,000 gas meters in Texas. The company has been opportunistically expanding into new geographies and verticals over the past few years, including water and wastewater, to help diversify its operating footprint. With the remainder of 2025 in mind, the recent rate case should underpin a majority of the earnings recovery we have envisioned. However, management expects that expansion into water and the SiEnergy acquisition will add roughly $0.25 - $0.30 per share.

Growth will likely be more moderate and consistent both in 2026 and out to late decade. After the expected recovery in 2025, growth will probably be limited to just over 3% in 2026. The company has already filed another rate case in Oregon, seeking a revenue increase of $60 million, or 5.8%. Further out, leadership is positioned to continue its capital investment cycle, targeting system upgrades and reinforcement across the main gas utility and growing number of subsidiaries, which should amount to multiple smaller rate adjustments. Also, although the company is likely to remain active on the acquisition front, with several bolt-on deals already inked, we won't include these in our projections until they are completed. We expect these initiatives to gas up the company's growth over the 3- to 5-years.

Northwest's multi-faceted approach to reinvigorating growth should pay off with above-average long-term upside from the recent quotation. Risks are a modest consideration, with regulatory and operational complexities potentially creating headwinds.

Earl B. Humes *May 23, 2025*

(A) Diluted earnings per share. Excludes nonrecurring items: '08, ($0.03); '09, $0.06; May not sum due to rounding. Next earnings report due in early August.
(B) Dividends historically paid in mid-February, May, August, and November.
■ Dividend reinvestment plan available.
(C) In millions.
(D) Includes intangibles. In 2024: $184 million, $4.60/share.

Company's Financial Strength	A
Stock's Price Stability	90
Price Growth Persistence	20
Earnings Predictability	25

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ONE GAS, INC. NYSE-OGS

RECENT PRICE 74.60 | P/E RATIO 17.3 (Trailing: 18.0 Median: 21.0) | RELATIVE P/E RATIO 0.97 | DIV'D YLD 3.6% | VALUE LINE

TIMELINESS 3 Raised 5/23/25
SAFETY 2 New 6/2/17
TECHNICAL 2 Raised 5/23/25
BETA .80 (1.00 = Market)

18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$50-$89	$70 (-5%)

2028-30 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	110	(+45%)	*13%*
Low	80	(+5%)	*5%*

Institutional Decisions

	2Q2024	3Q2024	4Q2024
to Buy	143	152	174
to Sell	160	146	124
Hld's(000)	53086	62020	63204

	44.3	51.8	67.4	79.5	87.8	96.7	97.0	81.9	92.3	84.3	78.9	82.3
High:	31.9	38.9	48.0	61.4	62.2	75.8	63.7	62.5	68.9	55.5	57.7	66.4

LEGENDS
35.00 x Dividends p sh
Relative Price Strength
Options: Yes
Shaded area indicates recession

Target Price Range 2028 | 2029 | 2030

200 160 100 80 60 50 40 30 20

Percent shares traded 21 14 7

% TOT. RETURN 5/12/25

	THIS STOCK	VL ARITH.* INDEX
1 yr.	20.8	6.0
3 yr.	-2.7	19.2
5 yr.	13.2	95.9

The shares of ONE Gas, Inc. began trading "regular-way" on the New York Stock Exchange on February 3, 2014. That happened as a result of the separation of ONEOK's natural gas distribution operation. Regarding the details of the spinoff, on January 31, 2014, ONEOK distributed one share of OGS common stock for every four shares of ONEOK common stock held by ONEOK shareholders of record as of the close of business on January 21. It should be mentioned that ONEOK did not retain any ownership interest in the new company.

CAPITAL STRUCTURE as of 3/31/25
Total Debt $3212.1 mill. **Due in 5 Yrs** $1500.0 mill.
LT Debt $2370.4 mill. **LT Interest** $145.0 mill.
(LT interest earned: 2.8x; total interest coverage: 2.8x)
Leases, Uncapitalized Annual rentals $5.9 mill.
Pfd Stock None
Pension Assets-12/24 $904.9 mill. **Oblig.** $882.1 mill.
Common Stock 59,930,528 shs.
as of 4/28/25
MARKET CAP: $4.5 billion (Mid Cap)

CURRENT POSITION ($MILL.)	2023	2024	3/31/25
Cash Assets	18.8	58.0	19.3
Other	746.4	871.9	736.9
Current Assets	765.2	929.9	756.2
Accts Payable	278.1	261.3	175.9
Debt Due	888.9	943.6	841.7
Other	310.2	253.4	259.8
Current Liab.	1477.2	1458.3	1277.4
Fix. Chg. Cov.	390%	325%	335%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '22-'24 to '28-'30
Revenues	1.5%	6.0%	*5.0%*
"Cash Flow"	6.5%	6.0%	*4.0%*
Earnings	7.0%	4.5%	*4.5%*
Dividends	12.0%	7.0%	*2.0%*
Book Value	3.5%	5.0%	*2.5%*

Calendar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2022	971.5	428.9	359.4	818.2	2578.0
2023	1032.1	398.1	335.8	606.0	2372.0
2024	758.3	354.1	340.4	630.8	2083.6
2025	935.2	*375*	*350*	*654.8*	*2315*
2026	*925*	*415*	*380*	*725*	*2445*

Calendar	EARNINGS PER SHARE [A] Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2022	1.83	.59	.44	1.23	4.08
2023	1.84	.58	.45	1.27	4.14
2024	1.75	.48	.34	1.34	3.91
2025	1.98	*.55*	*.39*	*1.38*	*4.30*
2026	*1.94*	*.63*	*.48*	*1.45*	*4.50*

Calendar	QUARTERLY DIVIDENDS PAID [B] Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	.58	.58	.58	.58	2.32
2022	.62	.62	.62	.62	2.48
2023	.65	.65	.65	.65	2.60
2024	.66	.66	.66	.66	2.64
2025	.67	.67			

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	© VALUE LINE PUB. LLC	28-30
	29.62	27.30	29.43	31.08	31.32	28.78	33.72	46.58	41.95	34.80	*37.65*	*38.80*	Revenues per sh	*55.00*
	4.82	5.43	5.96	6.32	6.96	7.36	7.71	8.13	9.04	8.68	*9.45*	*9.85*	"Cash Flow" per sh	*11.00*
	2.24	2.65	3.02	3.25	3.51	3.68	3.85	4.08	4.14	3.91	*4.30*	*4.50*	Earnings per sh [A]	*5.25*
	1.20	1.40	1.68	1.84	2.00	2.16	2.32	2.48	2.60	2.64	*2.68*	*2.72*	Div'ds Decl'd per sh [B]■	*2.90*
	5.63	5.91	6.81	7.50	7.91	8.87	9.23	11.01	11.79	11.74	*11.65*	*11.60*	Cap'l Spending per sh	*11.15*
	35.24	36.12	37.47	38.86	40.35	42.01	43.81	46.69	48.91	51.85	*53.75*	*55.50*	Book Value per sh	*56.60*
	52.26	52.28	52.31	52.57	52.77	53.17	53.63	55.35	56.55	59.88	*61.50*	*63.00*	Common Shs Outst'g [C]	*70.00*
	19.8	22.7	23.5	23.1	25.3	21.7	18.9	19.9	18.0	17.0	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	*18.0*
	1.00	1.19	1.18	1.25	1.35	1.11	1.02	1.15	1.01	.90			Relative P/E Ratio	*1.00*
	2.7%	2.3%	2.4%	2.5%	2.3%	2.7%	3.2%	3.1%	3.5%	4.0%			Avg Ann'l Div'd Yield	*3.1%*
	1547.7	1427.2	1539.6	1633.7	1652.7	1530.3	1808.6	2578.0	2372.0	2083.6	*2315*	*2445*	Revenues ($mill)	*3850*
	119.0	140.1	159.9	172.2	186.7	196.4	206.4	221.7	231.2	222.9	*260*	*280*	Net Profit ($mill)	*370*
	38.0%	37.8%	36.4%	23.7%	18.7%	17.5%	16.3%	17.3%	14.9%	14.0%	*17.5%*	*17.5%*	Income Tax Rate	*20.0%*
	7.7%	9.8%	10.4%	10.5%	11.3%	12.8%	11.4%	8.6%	9.7%	10.7%	*11.2%*	*11.5%*	Net Profit Margin	*9.6%*
	39.5%	38.7%	37.8%	38.6%	37.7%	41.5%	61.1%	50.7%	43.8%	43.5%	*43.0%*	*43.0%*	Long-Term Debt Ratio	*45.0%*
	60.5%	61.3%	62.2%	61.4%	62.3%	58.5%	38.9%	49.3%	56.2%	56.5%	*57.0%*	*57.0%*	Common Equity Ratio	*55.0%*
	3042.9	3080.7	3153.5	3328.1	3415.5	3815.7	6032.9	5246.2	4926.3	5489.8	*5800*	*6135*	Total Capital ($mill)	*7200*
	3511.9	3731.6	4007.6	4283.7	4565.2	4867.1	5190.8	5628.8	6135.2	6645.9	*7050*	*7400*	Net Plant ($mill)	*8500*
	4.7%	5.2%	5.8%	5.9%	6.4%	6.0%	3.9%	5.0%	5.9%	5.4%	*6.0%*	*6.0%*	Return on Total Cap'l	*6.5%*
	6.5%	7.4%	8.2%	8.4%	8.8%	8.8%	8.8%	8.6%	8.4%	7.2%	*8.0%*	*8.0%*	Return on Shr. Equity	*9.5%*
	6.5%	7.4%	8.2%	8.4%	8.8%	8.8%	8.8%	8.6%	8.4%	7.2%	*8.0%*	*8.0%*	Return on Com Equity	*9.5%*
	3.1%	3.5%	3.7%	3.7%	3.8%	3.7%	3.5%	3.4%	3.2%	2.4%	*3.0%*	*3.0%*	Retained to Com Eq	*4.0%*
	53%	52%	55%	56%	56%	58%	60%	60%	62%	67%	*63%*	*61%*	All Div'ds to Net Prof	*55%*

BUSINESS: ONE Gas, Inc. provides natural gas distribution services to more than two million customers. There are three divisions: Oklahoma Natural Gas, Kansas Gas Service, and Texas Gas Service. The company purchased 149 Bcf of natural gas supply in 2024, compared to 160 Bcf in 2023. Total volumes delivered by customer (fiscal 2024): transportation, 60.7%; residential, 28.6%; commercial & industrial, 10.1%; other, .6%. ONE Gas has around 3,900 employees. BlackRock owns 14.5% of common stock; The Vanguard Group, 11.6%; American Century Investment, 8.0%; officers and directors, 1.2% (4/25 Proxy). CEO: Robert S. McAnnally. Incorporated: Oklahoma. Address: 15 East Fifth Street, Tulsa, Oklahoma 74103. Tel.: 918-947-7000. Internet: www.onegas.com.

ONE Gas got off to an auspicious start in 2025. First-quarter earnings per share advanced 13.1%, to $1.98, relative to the prior-year tally of $1.75. That stemmed partially from benefits from new rates. Another contributing factor was higher residential sales, which reflected net customer growth in both Oklahoma and Texas. But increased depreciation & amortization expense, due to additional capital investments, provided somewhat of an offset to the good results. Also, employee-related costs climbed attributable, to a certain degree, to planned investments in the company's workforce. Still, it seems that full-year profits will grow 10%, to $4.30 a share, versus 2024's $3.91 total. Turning to 2026, the bottom line might rise at a slower (though still respectable) 5% rate, to $4.50 per share, given the tough comparison.

Finances are sound. When the March period concluded, cash on hand resided at $19.3 million (excluding $8.9 million in restricted cash). Furthermore, ONE Gas possesses a $1.3 billion revolving credit facility maturing in March, 2028. Also, at the end of the first quarter, long-term debt was a manageable 43% of total capital and short-term borrowings of $841.7 million did not appear to be a big hurdle. So, the company should continue to handle its obligations with little difficulty.

This year's capital expenditures, including asset removal costs, are expected to be roughly $750 million. (That would be moderately below the 2024 figure of $762.1 million.) The majority of the budget is devoted to system integrity and pipeline replacement projects. It's worth mentioning that the energy firm projects total spending to be $4.0 billion between 2025 and 2029, with around the same percentage of funds allocated to where they are at present. These goals seem achievable assuming, of course, that the balance sheet remains in solid shape.

What is an investor to do? The equity's dividend yield looks decent when stacked against those of other stocks in *Value Line's* Natural Gas Utility group. But at the recent quotation, capital gains potential for the pull to 2028-2030 is not alluring. These shares are ranked just 3 (Average) for Timeliness, as well.

Frederick L. Harris, III *May 23, 2025*

(A) Diluted EPS. Excludes nonrecurring gain: 2017, $0.06. Next earnings report due early August. Quarterly EPS figures for 2022 don't equal total due to rounding.
(B) Dividends historically paid in early March, June, Sept., and Dec. ■ Dividend reinvestment plan. Direct stock purchase plan.
(C) In millions.

Company's Financial Strength	A
Stock's Price Stability	85
Price Growth Persistence	40
Earnings Predictability	100

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SOUTHWEST GAS NYSE-SWX

RECENT PRICE **69.80** | P/E RATIO **19.8** (Trailing: 25.4 Median: 21.0) | RELATIVE P/E RATIO **1.11** | DIV'D YLD **3.6%** | **VALUE LINE**

TIMELINESS — Suspended 11/17/23
SAFETY 2 Raised 2/23/24
TECHNICAL — Suspended 11/17/23
BETA .80 (1.00 = Market)

18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$59-$94	$77 (10%)

2028-30 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	105	(+50%)	*13%*
Low	75	(+5%)	*6%*

Institutional Decisions

	2Q2024	3Q2024	4Q2024
to Buy	141	144	163
to Sell	131	138	132
Hld's(000)	66812	73232	74695

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
High:	64.2	63.7	79.6	86.9	86.0	92.9	81.6	73.5	95.6	68.0	80.3	78.9						
Low:	47.2	50.5	53.5	72.3	62.5	73.3	45.7	57.0	59.5	53.8	57.6	64.7						

LEGENDS
0.80 x Dividends p sh divided by Interest Rate
Relative Price Strength
Options: Yes
Shaded area indicates recession

Target Price Range 2028 | 2029 | 2030

Percent shares traded 15 10 5

% TOT. RETURN 5/12/25

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-5.5	6.0
3 yr.	-15.6	19.2
5 yr.	14.9	95.9

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	© VALUE LINE PUB. LLC	28-30
	42.00	40.18	41.07	41.77	42.08	45.61	52.00	51.82	53.00	54.31	56.72	57.68	60.91	73.90	75.93	71.22	*69.85*	*71.90*	Revenues per sh	*76.65*
	6.16	6.46	6.81	7.73	8.24	8.47	8.62	9.29	8.83	8.14	9.40	9.87	9.46	3.98	8.27	8.87	*10.10*	*11.20*	"Cash Flow" per sh	*13.00*
	1.94	2.27	2.43	2.86	3.11	3.01	2.92	3.18	3.62	3.68	3.94	4.14	3.39	d3.10	2.13	2.76	*3.50*	*4.00*	Earnings per sh [A]	*5.00*
	.95	1.00	1.06	1.18	1.32	1.46	1.62	1.80	1.98	2.08	2.18	2.28	2.38	2.46	2.48	2.48	*2.48*	*2.48*	Div'ds Decl'd per sh [B■†]	*3.00*
	4.81	4.73	8.29	8.57	7.86	8.53	10.30	11.15	12.97	14.44	17.06	14.43	11.84	12.80	12.19	13.18	*12.50*	*13.50*	Cap'l Spending per sh	*14.50*
	24.44	25.62	26.66	28.35	30.47	31.95	33.61	35.03	37.74	42.47	45.56	46.77	48.89	45.57	46.25	51.39	*54.25*	*55.50*	Book Value per sh	*58.65*
	45.09	45.56	45.96	46.15	46.36	46.52	47.38	47.48	48.09	53.03	55.01	57.19	60.42	67.12	71.56	71.78	*73.00*	*73.00*	Common Shs Outst'g [C]	*75.00*
	12.2	14.0	15.7	15.0	15.8	17.9	19.4	21.6	22.2	20.6	21.3	16.8	19.9	- -	29.0	25.9	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	*18.0*
	.81	.89	.98	.95	.89	.94	.98	1.13	1.12	1.11	1.13	.86	1.08	- -	1.61	1.44			Relative P/E Ratio	*1.00*
	4.0%	3.2%	2.8%	2.8%	2.7%	2.7%	2.9%	2.6%	2.5%	2.7%	2.6%	3.3%	3.5%	3.2%	4.0%	3.5%			Avg Ann'l Div'd Yield	*3.3%*
							2463.6	2460.5	2548.8	2880.0	3119.9	3298.9	3680.5	4960.0	5434.0	5112.4	*5100*	*5250*	Revenues ($mill)	*5750*
							138.3	152.0	173.8	182.3	213.9	232.3	200.8	d203.3	150.9	198.8	*255*	*290*	Net Profit ($mill)	*375*
							36.4%	33.9%	32.8%	25.3%	20.5%	21.6%	16.1%	- -	21.2%	15.1%	*21.0%*	*21.0%*	Income Tax Rate	*21.0%*
							5.6%	6.2%	6.8%	6.3%	6.9%	7.0%	5.5%	NMF	2.8%	3.9%	*5.0%*	*5.6%*	Net Profit Margin	*6.5%*
							49.3%	48.2%	49.8%	48.3%	47.9%	50.5%	58.2%	59.0%	58.2%	54.1%	*55.0%*	*55.0%*	Long-Term Debt Ratio	*56.0%*
							50.7%	51.8%	50.2%	51.7%	52.1%	49.5%	41.8%	41.0%	41.8%	45.9%	*45.0%*	*45.0%*	Common Equity Ratio	*44.0%*
							3143.5	3213.5	3613.3	4359.3	4806.4	5407.2	7069.5	7462.1	7919.9	8037.4	*8800*	*9000*	Total Capital ($mill)	*10000*
							3891.1	4132.0	4523.7	5093.2	5685.2	6176.1	7594.0	7024.5	7518.2	8109.1	*8700*	*9275*	Net Plant ($mill)	*10475*
							5.5%	5.8%	5.8%	5.2%	5.4%	5.3%	3.4%	NMF	3.8%	2.5%	*3.0%*	*3.0%*	Return on Total Cap'l	*4.0%*
							8.7%	9.1%	9.6%	8.1%	8.5%	8.7%	6.8%	NMF	4.6%	*5.5%*	*6.5%*	*7.0%*	Return on Shr. Equity	*8.5%*
							8.7%	9.1%	9.6%	8.1%	8.5%	8.7%	6.8%	NMF	4.6%	5.4%	*6.5%*	*7.0%*	Return on Com Equity	*8.5%*
							4.0%	4.1%	4.5%	3.6%	3.9%	4.0%	2.1%	NMF	NMF	.5%	*2.0%*	*2.5%*	Retained to Com Eq	*3.5%*
							54%	55%	53%	55%	54%	54%	69%	NMF	116%	90%	*71%*	*62%*	All Div'ds to Net Prof	*62%*

CAPITAL STRUCTURE as of 3/31/25
Total Debt $5046.8 mill. **Due in 5 Yrs** $1943 mill.
LT Debt $4327.9 mill. **LT Interest** $300 mill.
(Total interest coverage: 4.5x) (54% of Cap'l)

Leases, Uncapitalized Annual rentals $23.7 mill.
Pension Assets-12/23 $1158.0 mill.
Oblig. $1280.5 mill.

Pfd Stock None

Common Stock 71,912,673 shs.
as of 4/25/25

MARKET CAP: $5.0 billion (Mid Cap)

CURRENT POSITION ($MILL.)	2023	2024	3/31/25
Cash Assets	106.5	363.8	406.3
Other	1774.6	1100.7	1025.6
Current Assets	1881.1	1464.5	1431.9
Accts Payable	346.9	331.8	253.3
Debt Due	671.1	710.0	718.9
Other	666.8	790.3	834.3
Current Liab.	1684.8	1832.1	1806.5
Fix. Chg. Cov.	145%	310%	455%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '21-'23 to '28-'30
Revenues	5.5%	6.5%	*6.0%*
"Cash Flow"	-3.0%	-7.0%	*8.5%*
Earnings	- -	- -	*10.0%*
Dividends	6.5%	3.5%	*5.5%*
Book Value	4.5%	2.0%	*7.5%*

Calendar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2022	1267.4	1146.1	1125.6	1420.9	4960.0
2023	1603.3	1293.6	1169.5	1387.6	5434.0
2024	1581.0	1182.2	1079.2	1307.6	5112.4
2025	1296.5	*1240*	*1225*	*1338.5*	*5100*
2026	*1335*	*1275*	*1260*	*1380*	*5250*

Calendar	EARNINGS PER SHARE [A D] Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2022	1.58	d.10	d.18	d4.18	d3.10
2023	.67	.40	.04	1.02	2.13
2024	1.22	.25	- -	1.28	2.76
2025	1.58	*.65*	*.15*	*1.15*	*3.50*
2026	*1.80*	*.75*	*.15*	*1.30*	*4.00*

Calendar	QUARTERLY DIVIDENDS PAID [B■†] Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	.570	.595	.595	.595	2.36
2022	.595	.62	.62	.62	2.46
2023	.62	.62	.62	.62	2.48
2024	.62	.62	.62	.62	2.48
2025	.62				

BUSINESS: Southwest Gas Holdings, Inc. is the parent holding company of Southwest Gas. Centuri Group spun-off in IPO 4/22/24. Southwest Gas is a regulated gas distributor serving 2.3 million customers in Arizona, Nevada, and California. 2024 revenue mix: residential 68%; small commercial, 20%; large commercial and industrial, 5%; transportation, 7%. Southwest has 2,435 employees as of 12/31/24; Centuri has 8,687. Off. & dir. own .5% of common stock; Carl C. Icahn, 13.4%; BlackRock, 12.9%; The Vanguard Group, 10.1%; Corvex Management, 6.6% (3/25 Proxy). Chairman: Michael J. Melarkey. Pres. & CEO: Karen S. Haller. Inc.: DE. Addr.: 8360 S. Durango Drive, P.O. Box 98510 Las Vegas, Nevada 89193. Telephone: 702-876-7237. Internet: www.swgas.com.

Southwest Gas has posted good but slightly underwhelming recent results. The company reported earnings per share of $1.58, reflecting a record quarterly profit figure, but still landed below our target of $1.75. The December period figure was similarly just below our expectation. For now, the ongoing separation from the Centuri Group poses an ongoing headwind to the bottom line. Southwest still maintains a majority interest in the company, post IPO, and partially recognizes its losses, which amounted to $18 million in the March quarter. The utility has performed fairly well, supported by new rates implemented in Arizona and Nevada, along with steady customer growth, having added roughly 40,000 meters in a year. This has helped the utility's operating margin to expand by nearly $40 million. Lower operating and maintenance costs also benefited, but higher depreciation and interest expenses served to offset somewhat.

We've lowered our full-year 2025 targets, but still expect good results. As a result of ongoing struggles at the Centuri Group, we have cut a dime from our bottom-line estimate, now at $3.50 per share. However, the gas utility is going strong, and we still expect overall share-earnings growth of over 25% this year, with net income around $255. However, results will likely depend on management's plans for divesting from its position in Centuri. It's worth noting that we do not take divestitures into account when presenting our forecasts, until such actions are completed. As a result, it is likely that our estimates could prove conservative.

The utility is well positioned to capitalize on investment opportunities. Market dynamics in the company's territories remain favorable, bolstered by population growth and strength in sectors such as hospitality, manufacturing, and mining. Management expects to invest more than $4 billion over the next years, providing a significant infrastructure platform from which to generate long-term returns.

The stock appears to offer below average return prospects over the 3- to 5-year horizon, however. The shares remain unranked for Timeliness, due to the ongoing corporate restructuring.

Earl B. Humes *May 23, 2025*

(A) Diluted earnings. Excl. nonrec. gains (losses): '22, 10¢. Next egs. report due early August. **(B)** Dividends historically paid early March, June, September, and December. ■† Div'd reinvestment and stock purchase plan avail. **(C)** In millions. **(D)** Totals may not sum due to rounding. **(E)** Rank suspended 11/17/2023 for spin-off of the Centuri Group.

Company's Financial Strength	A
Stock's Price Stability	85
Price Growth Persistence	25
Earnings Predictability	5

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SPIRE INC. NYSE-SR

RECENT PRICE **72.19** | P/E RATIO **17.4** (Trailing: 17.8 Median: 18.0) | RELATIVE P/E RATIO **0.97** | DIV'D YLD **4.4%** | **VALUE LINE**

TIMELINESS 3 Raised 5/23/25
SAFETY 2 Raised 6/20/03
TECHNICAL 1 Raised 5/16/25
BETA .80 (1.00 = Market)

18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$55-$90	$73 (0%)

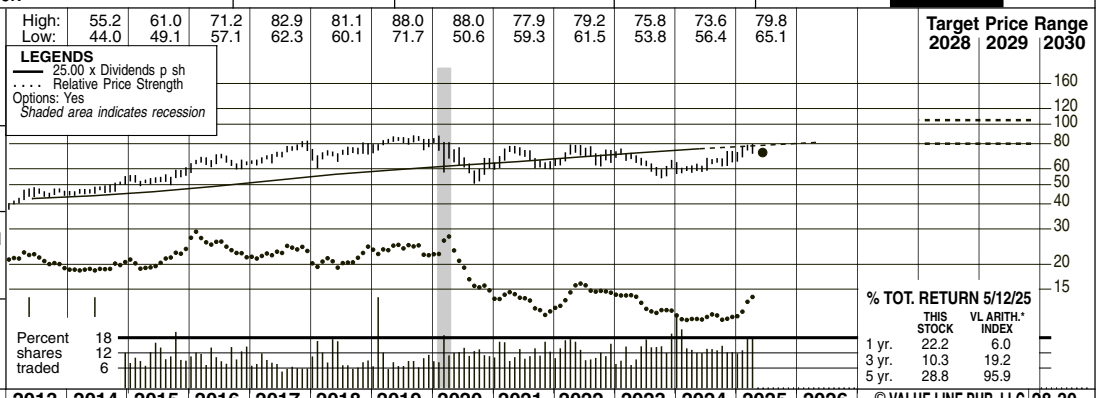
2028-30 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	105	(+45%)	*13%*
Low	80	(+10%)	*7%*

Institutional Decisions

	2Q2024	3Q2024	4Q2024
to Buy	160	159	181
to Sell	108	130	133
Hld's(000)	49797	57334	58958

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
High:	55.2	61.0	71.2	82.9	81.1	88.0	88.0	77.9	79.2	75.8	73.6	79.8						
Low:	44.0	49.1	57.1	62.3	60.1	71.7	50.6	59.3	61.5	53.8	56.4	65.1						
Revenues per sh [A]	85.49	77.83	71.48	49.90	31.10	37.68	45.59	33.68	36.07	38.78	38.30	35.96	43.24	41.88	50.12	44.94	*40.60*	*41.15*
"Cash Flow" per sh	4.56	4.11	4.62	4.58	3.12	3.87	6.15	6.16	6.54	7.55	7.12	5.25	9.09	8.44	8.60	8.92	*9.10*	*9.45*
Earnings per sh [A B]	2.92	2.43	2.86	2.79	2.02	2.35	3.16	3.24	3.43	4.33	3.52	1.44	4.96	3.95	3.85	4.19	*4.05*	*4.25*
Div'ds Decl'd per sh [C ■]	1.53	1.57	1.61	1.66	1.70	1.76	1.84	1.96	2.10	2.25	2.37	2.49	2.60	2.74	2.88	3.02	*3.14*	*3.26*
Cap'l Spending per sh	2.36	2.56	3.02	4.83	4.00	3.96	6.68	6.42	9.08	9.86	16.15	12.37	12.09	10.52	12.45	14.93	*14.00*	*14.40*
Book Value per sh [D]	23.32	24.02	25.56	26.67	32.00	34.93	36.30	38.73	41.26	44.51	45.14	44.19	46.74	49.08	50.29	51.83	*55.50*	*55.80*
Common Shs Outst'g [E]	22.17	22.29	22.43	22.55	32.70	43.18	43.36	45.65	48.26	50.67	50.97	51.60	51.70	52.50	53.20	57.70	*60.00*	*62.00*
Avg Ann'l P/E Ratio	13.4	13.7	13.0	14.5	21.3	19.8	16.5	19.6	19.8	16.7	22.8	51.1	13.6	17.5	17.3	14.6	*Bold figures are Value Line estimates*	
Relative P/E Ratio	.89	.87	.82	.92	1.20	1.04	.83	1.03	1.00	.90	1.21	2.62	.73	1.01	1.00	.76		
Avg Ann'l Div'd Yield	3.9%	4.7%	4.3%	4.1%	4.0%	3.8%	3.5%	3.1%	3.1%	3.1%	3.0%	3.4%	3.8%	4.0%	4.3%	4.9%		
Revenues ($mill) [A]							1976.4	1537.3	1740.7	1965.0	1952.4	1855.4	2235.5	2198.5	2666.3	2593.0	*2435*	*2550*
Net Profit ($mill)							136.9	144.2	161.6	214.2	184.6	88.6	271.7	220.8	217.5	250.9	*245*	*265*
Income Tax Rate							31.2%	32.5%	32.4%	--	15.7%	12.3%	20.1%	21.1%	15.1%	19.0%	*19.5%*	*19.5%*
Net Profit Margin							6.9%	9.4%	9.3%	10.9%	9.5%	4.8%	12.2%	10.0%	8.2%	9.7%	*10.1%*	*10.4%*
Long-Term Debt Ratio							53.0%	50.9%	50.0%	45.7%	45.0%	49.0%	52.5%	51.2%	54.9%	53.4%	*51.0%*	*52.0%*
Common Equity Ratio							47.0%	49.1%	50.0%	54.3%	49.7%	46.1%	43.2%	44.6%	41.3%	43.1%	*45.0%*	*44.0%*
Total Capital ($mill)							3345.1	3601.9	3986.3	4155.5	4625.6	4946.0	5597.3	5777.0	6471.3	6937.1	*7400*	*7865*
Net Plant ($mill)							2941.2	3300.9	3665.2	3970.5	4352.0	4680.1	5055.7	5370.4	5778.9	6243.3	*6725*	*7040*
Return on Total Cap'l							5.1%	4.9%	5.0%	6.3%	5.1%	2.9%	5.8%	4.9%	4.8%	5.1%	*5.0%*	*5.0%*
Return on Shr. Equity							8.7%	8.2%	8.1%	9.5%	7.3%	3.5%	10.2%	7.8%	7.5%	7.8%	*7.5%*	*7.5%*
Return on Com Equity							8.7%	8.2%	8.1%	9.5%	7.9%	3.2%	10.6%	8.0%	7.6%	7.9%	*7.5%*	*7.5%*
Retained to Com Eq							3.7%	3.3%	3.3%	4.7%	2.7%	NMF	5.1%	2.5%	1.9%	2.3%	*1.5%*	*1.5%*
All Div'ds to Net Prof							58%	59%	60%	51%	66%	NMF	54%	71%	76%	72%	*83%*	*82%*



Target Price Range

2028	2029	2030

% TOT. RETURN 5/12/25

	THIS STOCK	VL ARITH.* INDEX
1 yr.	22.2	6.0
3 yr.	10.3	19.2
5 yr.	28.8	95.9

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CAPITAL STRUCTURE as of 3/31/25
Total Debt $4756.0 mill. **Due in 5 Yrs**$1766.0 mill.
LT Debt $3348.5 mill. **LT Interest** $185.0 mill.
(Total interest coverage: 2.5x)

Leases, Uncapitalized Annual rentals $9.8 mill.
Pension Assets-9/24 $704.5 mill.
Oblig. $887.3 mill.
Pfd Stock $242.0 mill. **Pfd Div'd** $14.8 mill.
Common Stock 59,016,874 shs.
as of 4/25/25

MARKET CAP: $4.3 billion (Mid Cap)

CURRENT POSITION ($MILL.)	2023	2024	3/31/25
Cash Assets	5.6	4.5	15.2
Other	1071.3	766.8	892.6
Current Assets	1076.9	771.3	907.8
Accts Payable	253.1	237.2	283.5
Debt Due	1112.1	989.0	1407.5
Other	390.2	477.7	421.5
Current Liab.	1755.4	1703.9	2112.5
Fix. Chg. Cov.	294%	305%	315%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '22-'24 to '28-'30
Revenues	1.5%	4.0%	*1.0%*
"Cash Flow"	8.5%	4.0%	*4.0%*
Earnings	5.5%	1.0%	*4.5%*
Dividends	5.5%	5.0%	*4.0%*
Book Value	5.0%	3.0%	*2.5%*

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.)[A] Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2022	555.4	880.9	448.0	314.2	2198.5
2023	814.0	1123.4	418.5	310.4	2666.3
2024	756.6	1128.5	414.1	293.8	2593.0
2025	669.1	1051.3	*415*	*299.6*	*2435*
2026	*715*	*1100*	*425*	*310*	*2550*

Fiscal Year Ends	EARNINGS PER SHARE [A B F] Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2022	1.01	3.27	d.10	d.20	3.95
2023	1.66	3.33	d.48	d.66	3.85
2024	1.52	3.58	d.28	d.51	4.19
2025	1.34	3.51	*d.30*	*d.50*	*4.05*
2026	*1.43*	*3.57*	*d.27*	*d.48*	*4.25*

Calendar	QUARTERLY DIVIDENDS PAID [C ■] Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	.65	.65	.65	.65	2.60
2022	.685	.685	.685	.685	2.74
2023	.72	.72	.72	.72	2.88
2024	.755	.755	.755	.755	3.02
2025	.785	.785			

BUSINESS: Spire Inc., formerly known as the Laclede Group, Inc., is a holding company for natural gas utilities, which distributes natural gas across Missouri, including the cities of St. Louis and Kansas City, Alabama, and Mississippi. Has roughly 1.7 million customers. Acquired Missouri Gas 9/13, Alabama Gas Co 9/14. Utility therms sold and transported in fiscal 2024: 3.1 bill. Revenue mix for regulated operations: residential, 66%; commercial and industrial, 24%; transportation, 5%; other, 5%. Officers and directors own 2.3% of common shares; BlackRock, 11.9%; The Vanguard Group, 9.6% (12/24 proxy). Chairman: Rob L. Jones; CEO: Scott Doyle. Inc.: Missouri. Address: 700 Market Street, St. Louis, Missouri 63101. Tel.: 314-342-0500. Internet: www.spireenergy.com.

In April, Spire Inc. announced that its CEO Steve Lindsey was "terminated without cause." The company added, however, that the move was not because of some material or unexpected financial event. In any case, his successor Scott Doyle had been serving as the chief operating officer. (When Mr. Lindsey took a leave of absence earlier this year for health-related reasons, he filled in.) Prior to joining Spire in January of 2024, Mr. Doyle was executive vice president of utility operations at CenterPoint Energy. All things considered, we believe that the company is in capable hands.

Results have been lackluster thus far in fiscal 2025 (concludes September 30th). First-half profits of $4.85 a share were 5% lower than the previous year's $5.10 tally. That was due partly to reduced earnings from the Gas Marketing arm, reflecting less favorable market conditions combined with greater transportation and storage fees. The number of diluted shares outstanding rose, too. But the Gas Utility division and Midstream unit had improved performances during the period. Nevertheless, for the whole year, we expect Spire's bottom line to slip about 3%, to $4.05 per share, compared to fiscal 2024's $4.19 total. Regarding fiscal 2026, though, earnings per share may rebound around 5%, to $4.25. That is based, to some extent, on our assumption that the business climate is better. Improvements in operating efficiencies should also help.

The capital spending budget for this year was increased from $790 million to $840 million. (That's slightly below the fiscal 2024 level of $861.3 million.) The majority of the funds are being used for infrastructure upgrades, the installation of advanced meters, plus new business development initiatives at the utilities. Management adds that it expects total capital expenditures from fiscal 2025 through fiscal 2034 to be $7.4 billion. If finances stay healthy, the company ought to have little trouble achieving those goals.

These shares' big draw is the dividend yield. It stacks up nicely versus other Natural Gas Utility stocks covered by *Value Line*. Also, we expect more steady hikes in the payout out to 2028-2030.

Frederick L. Harris, III *May 23, 2025*

(A) Fiscal year ends Sept. 30th.
(B) Based on diluted shares outstanding. Next earnings report due late July.
(C) Dividends paid in early January, April, July, and October. ■ Dividend reinvestment plan available.
(D) Includes deferred charges. In '24: $1,171.6 mill., $20.31/sh.
(E) In millions.
(F) Quarterly earnings may not sum due to rounding or change in shares outstanding.

Company's Financial Strength	B++
Stock's Price Stability	95
Price Growth Persistence	25
Earnings Predictability	50

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ALLIANT ENERGY NDQ-LNT

RECENT PRICE **61.72** | P/E RATIO **19.0** (Trailing: 21.3 Median: 21.0) | RELATIVE P/E RATIO **1.09** | DIV'D YLD **3.3%** | **VALUE LINE**

TIMELINESS 4 Lowered 5/23/25
SAFETY 1 Raised 9/6/24
TECHNICAL 1 Raised 5/16/25
BETA .80 (1.00 = Market)

18-Month Target Price Range

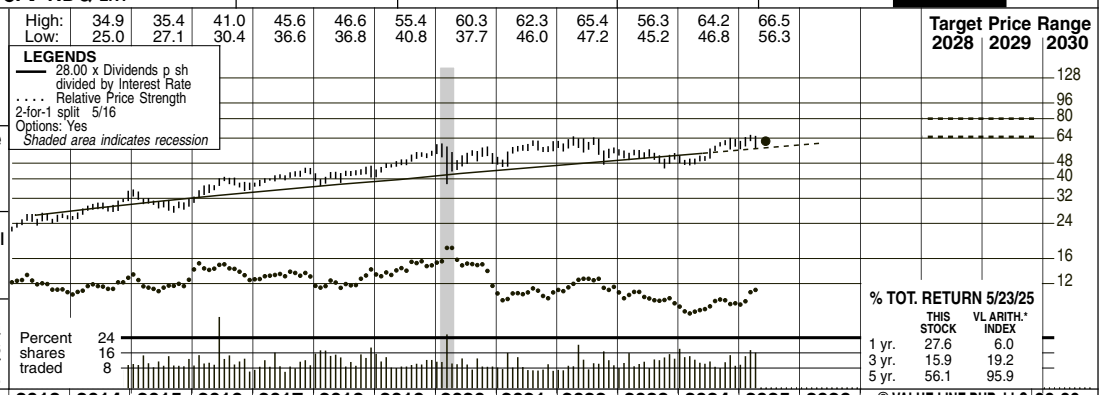
Low-High	Midpoint (% to Mid)
$56-$80	$68 (10%)

2028-30 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	80	(+30%)	*10%*
Low	65	(+5%)	*5%*

Institutional Decisions

	2Q2024	3Q2024	4Q2024
to Buy	314	338	356
to Sell	265	271	277
Hld's(000)	205430	229417	237566



% TOT. RETURN 5/23/25

	THIS STOCK	VL ARITH.* INDEX
1 yr.	27.6	6.0
3 yr.	15.9	19.2
5 yr.	56.1	95.9

2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	© VALUE LINE PUB. LLC	28-30
15.51	15.40	16.51	13.94	14.77	15.10	14.34	14.58	14.62	14.97	14.89	13.67	14.65	16.74	15.72	15.51	*17.30*	*17.95*	Revenues per sh	*18.95*
2.10	2.60	2.75	2.95	3.34	3.49	3.45	3.43	3.97	4.32	4.59	4.92	5.25	5.40	5.38	5.70	*5.85*	*6.05*	"Cash Flow" per sh	*6.85*
.95	1.38	1.38	1.53	1.65	1.74	1.69	1.65	1.99	2.19	2.33	2.47	2.63	2.73	2.78	2.69	*3.25*	*3.45*	Earnings per sh A	*4.25*
.75	.79	.85	.90	.94	1.02	1.10	1.18	1.26	1.34	1.42	1.52	1.61	1.71	1.81	1.92	*2.04*	*2.16*	Div'd Decl'd per sh B ■ †	*2.43*
5.43	3.91	3.03	5.22	3.32	3.78	4.25	5.26	6.34	6.92	6.69	5.47	4.67	5.91	7.24	8.76	*5.60*	*5.60*	Cap'l Spending per sh	*5.40*
12.54	13.05	13.57	14.12	14.79	15.54	16.41	16.96	18.08	19.43	21.24	22.76	23.91	24.99	26.46	27.29	*28.85*	*29.00*	Book Value per sh C	*31.90*
221.31	221.79	222.04	221.97	221.89	221.87	226.92	227.67	231.35	236.06	245.02	249.87	250.47	251.14	256.10	256.69	*256.70*	*257.00*	Common Shs Outst'g D	*257.00*
13.9	12.5	14.5	14.5	15.3	16.6	18.1	22.3	20.6	19.1	21.2	21.2	21.2	21.4	18.8	20.1	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	*17.5*
.93	.80	.91	.92	.86	.87	.91	1.17	1.04	1.03	1.13	1.09	1.15	1.24	1.05	1.06			Relative P/E Ratio	*.95*
5.7%	4.6%	4.3%	4.1%	3.7%	3.5%	3.6%	3.2%	3.1%	3.2%	2.9%	2.9%	2.9%	2.9%	3.5%	3.5%			Avg Ann'l Div'd Yield	*3.7%*
3253.6	3320.0	3382.2	3534.5	3647.7	3416.0	3669.0	4205.0	4027.0	3981.0	*4420*	*4610*	Revenues ($mill)	*4870*
390.9	384.0	466.1	522.3	567.4	624.0	674.0	686.0	703.0	690.0	*835*	*885*	Net Profit ($mill)	*975*
15.3%	13.4%	12.5%	8.4%	10.8%	- -	- -	3.1%	.6%	2.0%	*2.0%*	*2.0%*	Income Tax Rate	*2.0%*
9.4%	16.3%	10.7%	14.5%	16.3%	8.8%	3.7%	8.7%	14.2%	10.9%	*10.0%*	*10.0%*	AFUDC % to Net Profit	*4.0%*
47.3%	51.5%	47.8%	52.3%	50.6%	53.5%	52.9%	55.0%	54.8%	55.3%	*55.5%*	*55.5%*	Long-Term Debt Ratio	*52.0%*
50.0%	46.1%	49.8%	45.7%	47.6%	44.9%	47.1%	45.0%	45.2%	44.7%	*44.5%*	*44.5%*	Common Equity Ratio	*48.0%*
7446.3	8377.6	8392.8	10032	10938	12657	12725	13944	15002	15681	*16530*	*16750*	Total Capital ($mill)	*17070*
8970.2	9809.9	10798	12462	13527	14336	14987	16247	17157	18701	*18600*	*18900*	Net Plant ($mill)	*19180*
6.3%	5.6%	6.7%	6.3%	6.3%	5.9%	6.3%	6.1%	6.0%	5.8%	*6.5%*	*6.5%*	Return on Total Cap'l	*7.0%*
10.0%	9.5%	10.6%	10.9%	10.5%	10.6%	11.3%	10.9%	10.4%	9.9%	*11.5%*	*11.5%*	Return on Shr. Equity	*12.0%*
10.2%	9.7%	10.9%	11.2%	10.7%	10.8%	11.0%	10.9%	10.4%	9.9%	*11.5%*	*11.5%*	Return on Com Equity E	*12.0%*
3.6%	2.8%	4.0%	4.4%	4.2%	4.2%	4.3%	4.1%	3.6%	2.8%	*4.0%*	*4.0%*	Retained to Com Eq	*4.5%*
66%	72%	64%	62%	61%	62%	62%	62%	65%	71%	*63%*	*63%*	All Div'ds to Net Prof	*62%*

CAPITAL STRUCTURE as of 3/31/25
Total Debt $10629 mill. **Due in 5 Yrs** $4371 mill.
LT Debt $8580 mill. **LT Interest** $370 mill.
(LT interest earned: 2.8x)

Leases, Uncapitalized Annual rentals $3 mill.

Pension Assets-12/24 $715 mill.
Oblig $841 mill.

Pfd Stock None

Common Stock 256,876,299 shs.

MARKET CAP: $15.9 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2022	2023	2024
% Change Retail Sales (KWH)	-.7	-.4	Unc
Avg. Indust. Use (MWH)	11494	11435	11161
Avg. Indust. Revs. per KWH (¢)	8.39	8.47	8.53
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	5629	5856	5638
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+.7	+.7	+.7
Fixed Charge Cov. (%)	NA	NA	NA

ANNUAL RATES

of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '22-'24 to '28-'30
Revenues	1.0%	1.5%	*2.5%*
"Cash Flow"	5.5%	5.0%	*2.0%*
Earnings	5.5%	4.5%	*6.0%*
Dividends	6.5%	6.0%	*6.0%*
Book Value	6.0%	6.0%	*4.0%*

QUARTERLY REVENUES ($ mill.)

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2022	1068	943	1135	1059	4205
2023	1077	912	1077	961	4027
2024	1030	894	1081	976	3981
2025	1128	*975*	*1145*	*1172*	*4420*
2026	*1110*	*1050*	*1215*	*1235*	*4610*

EARNINGS PER SHARE A

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2022	.77	.63	.90	.43	2.73
2023	.65	.64	1.02	.47	2.78
2024	.62	.34	1.15	.58	2.69
2025	.83	*.60*	*1.10*	*.72*	*3.25*
2026	*.78*	*.73*	*1.21*	*.73*	*3.45*

QUARTERLY DIVIDENDS PAID B ■ †

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	.4025	.4025	.4025	.4025	1.61
2022	.4275	.4275	.4275	.4275	1.71
2023	.4525	.4525	.4525	.4525	1.81
2024	.48	.48	.48	.48	1.92
2025	.48	.48			

BUSINESS: Alliant Energy Corporation is the parent company of Interstate Power and Light Company (IPL) and Wisconsin Power and Light Company (WPL). Together, the utility subsidiaries serve approximately one million electric and 430,000 natural gas customers in Wisconsin and Iowa. Electric revenue: residential, 37%; commercial, 24%; industrial, 28%; wholesale, 8%; other, 3%. Generating sources: coal, 18%; gas, 41%; wind, 16%; other, 1%; purchased, 24%. Fuel costs: 19% of revenues. '24 reported depreciation rates: 2.9%-6.1%. Has 2,998 employees. President & CEO: Lisa M. Barton. Incorporated: Wisconsin. Address: 4902 North Biltmore Lane, Madison, Wisconsin 53718-2148. Telephone: 608-458-3311. Internet: www.alliantenergy.com.

Alliant Energy could enjoy strong power demand across its two-state service area over the next several years. That's, in part, thanks to the success that the electric utility and its municipal partners are having in attracting new business to Wisconsin and Iowa. To wit, in the March quarter, Alliant inked an additional energy supply agreement (ESA) with a data center client operating out of the Big Cedar Industrial Center in Cedar Rapids, Iowa. It also recently cinched an ESA with a data center customer in Beaver Dam, Wisconsin.

Up next is securing regulatory approval for the individual customer rates that Alliant plans to charge these data center customers. As we understand it, the Iowa Utility Commission was recently reviewing the first of Alliant's data-center submissions.

The utility's 2025-2029 capital plan totaled approximately $11.5 billion, as of mid-May. A majority of the debt- and equity-funded spending has been earmarked for renewable-energy and energy-storage projects. Alliant also expects to add natural gas-fueled capacity. That said, we do worry some that it may have to rely temporarily on purchased power to meet its growing needs.

Alliant is vulnerable to potential changes in government policy at it relates to tax credits for renewable power generation. The utility regularly sells the tax credits that it earns from producing clean power. However, that income stream seems increasingly at risk under the new Trump Administration and possible changes to or rollbacks of the Biden-era Inflation Reduction Act. Still, Alliant is apparently able to request rate relief under certain circumstances, including the termination of these tax credits.

Alliant Energy shares are an untimely selection for relative year-ahead price performance. And with the stock up 23% in price over the past 12 months, long-term appreciation potential no longer stands out. Still, the utility company boasts an attractive, well-covered dividend that could hold some appeal for income-oriented accounts (current yield: 3.3% versus 2.3% for the *Value Line* universe as a whole).

Nils C. Van Liew *June 6, 2025*

(A) Diluted EPS. Excl. nonrecurring losses: '11, 1¢; '12, 8¢. '20 & '21 EPS don't sum due to rounding. Next earnings report due late July. **(B)** Dividends historically paid in mid-Feb., May, Aug., and Nov. ■ Dividend reinvestment plan avail. † Shareholder investment plan avail. **(C)** Incl. deferred charges. In '21: $1,980 mill., $7.91/sh. **(D)** In millions, adj. for split. **(E)** Rate base: Orig. cost. Rates all'd on com. eq. in IA in '20: various; in WI in '22: 10%; earned on avg. com. eq., '21: 11.3%. Regulatory Climate: Wisconsin, Above Average; Iowa, Average.

Company's Financial Strength	A+
Stock's Price Stability	100
Price Growth Persistence	55
Earnings Predictability	100

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AMERICAN ELEC. PWR. NDQ-AEP

RECENT PRICE **102.88** | P/E RATIO **17.4** (Trailing: 17.5 Median: 18.0) | RELATIVE P/E RATIO **1.00** | DIV'D YLD **3.7%** | **VALUE LINE**

TIMELINESS 3 Raised 5/23/25
SAFETY 1 Raised 3/17/17
TECHNICAL 1 Raised 5/23/25
BETA .70 (1.00 = Market)

18-Month Target Price Range

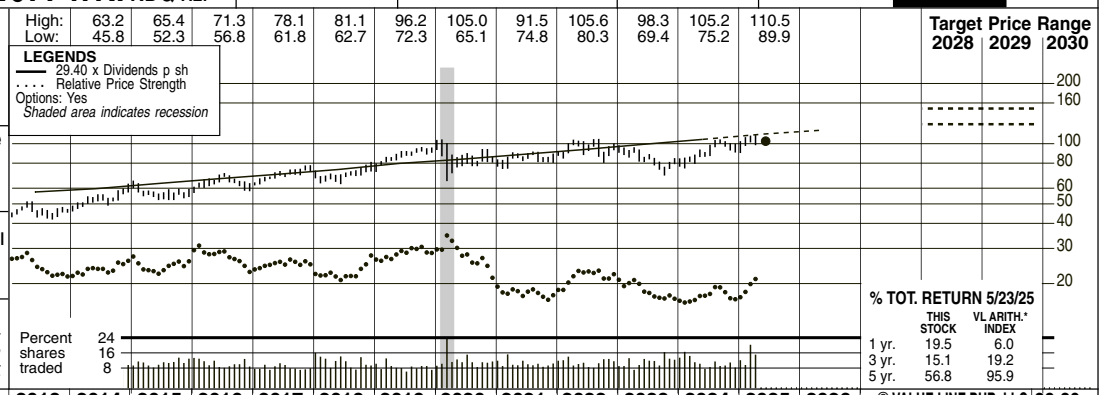
Low-High	Midpoint (% to Mid)
$77-$125	$101 (0%)

2028-30 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	150	(+45%)	*13%*
Low	125	(+20%)	*8%*

Institutional Decisions

	2Q2024	3Q2024	4Q2024
to Buy	695	712	755
to Sell	540	590	654
Hld's(000)	404836	455335	458507



2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	© VALUE LINE PUB. LLC	28-30
28.22	30.01	31.27	30.77	31.48	34.78	33.51	33.31	31.35	32.84	31.49	30.04	33.30	38.20	36.08	37.01	*39.65*	*41.20*	Revenues per sh	*46.35*
6.32	6.29	6.83	6.92	7.02	7.57	7.98	8.47	7.95	8.77	9.35	10.28	10.98	10.72	10.92	11.71	*12.20*	*12.80*	"Cash Flow" per sh	*15.70*
2.97	2.60	3.13	2.98	3.18	3.34	3.59	4.23	3.62	3.90	4.08	4.42	4.96	5.09	5.24	5.61	*5.90*	*6.30*	Earnings per sh A	*7.70*
1.64	1.71	1.85	1.88	1.95	2.03	2.15	2.27	2.39	2.53	2.71	2.84	3.00	3.17	3.37	3.57	*3.80*	*3.98*	Div'd Decl'd per sh B ■ †	*4.31*
6.19	5.07	5.74	6.45	7.75	8.68	9.37	9.98	11.79	12.89	12.43	12.72	11.43	13.18	13.89	14.02	*14.10*	*14.10*	Cap'l Spending per sh	*14.00*
27.49	28.33	30.33	31.37	32.98	34.37	36.44	35.38	37.17	38.58	39.73	41.38	44.49	46.60	48.46	50.63	*52.35*	*55.55*	Book Value per sh C	*60.90*
478.05	480.81	483.42	485.67	487.78	489.40	491.05	491.71	492.01	493.25	494.17	496.60	504.21	513.87	526.18	532.9	*535.00*	*540.00*	Common Shs Outst'g D	*550.00*
10.0	13.4	11.9	13.8	14.5	15.9	15.8	15.2	19.3	18.0	21.4	19.6	17.1	21.1	16.2	16.2	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	*18.0*
.67	.85	.75	.88	.81	.84	.80	.80	.97	.97	1.14	1.01	.92	1.23	.93	.90			Relative P/E Ratio	*1.00*
5.5%	4.9%	5.0%	4.6%	4.2%	3.8%	3.8%	3.5%	3.4%	3.6%	3.1%	3.3%	3.5%	3.3%	4.5%	3.6%			Avg Ann'l Div'd Yield	*3.3%*
16453	16380	15425	16196	15561	14919	16792	19640	18982	19721	*21250*	*22650*	Revenues ($mill)	*25500*
1763.4	2073.6	1783.2	1923.8	2019.0	2200.1	2448.1	2307.2	2208.1	2967.1	*3130*	*3400*	Net Profit ($mill)	*4235*
35.1%	26.8%	33.7%	5.8%	.7%	1.9%	4.6%	NMF	NMF	NMF	*21.0%*	*21.0%*	Income Tax Rate	*21.0%*
11.0%	8.0%	8.0%	10.7%	12.7%	9.7%	7.8%	7.0%	7.0%	7.0%	*6.5%*	*6.0%*	AFUDC % to Net Profit	*5.0%*
49.8%	50.0%	51.5%	53.2%	56.1%	58.5%	58.3%	58.5%	58.2%	58.1%	*58.0%*	*58.0%*	Long-Term Debt Ratio	*57.5%*
50.2%	50.0%	48.5%	46.8%	43.9%	41.5%	41.7%	42.0%	42.0%	42.4%	*42.0%*	*42.0%*	Common Equity Ratio	*42.5%*
35633	34775	37707	40677	44759	49537	53734	57520	62837	67528	*70730*	*72500*	Total Capital ($mill)	*75900*
46133	45639	50262	55099	60138	63902	66001	71283	76693	82416	*81250*	*84250*	Net Plant ($mill)	*87300*
6.1%	7.2%	5.9%	5.9%	5.6%	5.6%	5.6%	4.0%	3.6%	4.1%	*4.5%*	*4.5%*	Return on Total Cap'l	*5.0%*
9.9%	11.9%	9.8%	10.1%	10.3%	10.7%	11.1%	9.7%	8.7%	11.0%	*10.0%*	*10.0%*	Return on Shr. Equity	*11.0%*
9.9%	11.9%	9.8%	10.1%	10.3%	10.7%	11.1%	9.7%	8.7%	11.0%	*10.0%*	*10.0%*	Return on Com Equity	*11.0%*
3.9%	5.5%	3.2%	3.5%	3.4%	3.8%	4.3%	2.9%	2.4%	3.2%	*4.0%*	*4.0%*	Retained to Com Eq	*4.5%*
60%	54%	67%	65%	67%	65%	61%	70%	63%	63%	*63%*	*63%*	All Div'ds to Net Prof	*61%*

CAPITAL STRUCTURE as of 3/31/25
Total Debt $42157 mill. **Due in 5 Yrs** $12886 mill.
LT Debt $38811 mill. **LT Interest** $1400 mill.

Leases, Uncapitalized Annual rentals $119.6 mill.

Pfd Stock None

Common Stock 534,195,026 shs.

MARKET CAP: $56.6 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2022	2023	2024
% Change Retail Sales (KWH)	- -	+3.0	- -
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+1.0	NA	NA
Fixed Charge Cov. (%)	243	272	285

ANNUAL RATES

of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '22-'24 to '28-'30
Revenues	.5%	-.5%	*3.0%*
"Cash Flow"	5.0%	5.5%	*5.5%*
Earnings	5.0%	4.0%	*6.5%*
Dividends	5.0%	5.0%	*5.5%*
Book Value	3.5%	3.5%	*6.0%*

QUARTERLY REVENUES ($ mill.) E

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2022	4593	4640	5526	4881	19640
2023	4690	4373	5342	4577	18982
2024	5026	4579	5420	4696	19721
2025	5463	*5100*	*5750*	*4937*	*21250*
2026	*5800*	*5550*	*6000*	*5300*	*22650*

EARNINGS PER SHARE A

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2022	1.22	1.20	1.62	1.05	5.09
2023	1.11	1.13	1.77	1.23	5.24
2024	1.27	1.25	1.85	1.24	5.61
2025	1.54	*1.25*	*1.90*	*1.21*	*5.90*
2026	*1.50*	*1.45*	*1.95*	*1.40*	*6.30*

QUARTERLY DIVIDENDS PAID B ■ †

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	.74	.74	.74	.78	3.00
2022	.78	.78	.78	.83	3.17
2023	.83	.83	.83	.88	3.37
2024	.88	.88	.88	.93	3.57
2025	.93	.93			

BUSINESS: American Electric Power Company Inc. (AEP), through 10 operating utilities, serves 5.5 million customers in Arkansas, Kentucky, Indiana, Louisiana, Michigan, Ohio, Oklahoma, Tennessee, Texas, Virginia, & West Virginia. Has a transmission subsidiary. Electric revenue breakdown: residential, 43%; commercial, 23%; industrial, 18%; wholesale, 10%; other, 6%. Sold commercial barge operation in '15. Generating sources not available. Fuel costs: 33% of revenues. '23 reported depreciation rates (utility): 2.6%-12.5%. Has approximately 16,700 employees. Chief Executive Officer: William J. Fehrman. Incorporated: New York. Address: 1 Riverside Plaza, Columbus, Ohio 43215-2373. Telephone: 614-716-1000. Internet: www.aep.com.

American Electric Power looks set to post another year of solid results. First-quarter numbers came in well above our expectations, with earnings per share of $1.54 versus our estimate of $1.40. Revenue grew 9.2% year-over-year to $5.46 billion, led by a 12.3% increase in commercial load, largely driven by continued growth in the data center sector. The company reaffirmed its 2025 profit target range of $5.75-$5.95 a share and long-term growth target of 6%-8%. Our 2025 profit estimate now stands at $5.90, up a nickel from our prior view. Recent regulatory approvals in Indiana, Kentucky, and West Virginia reinforce AEP'S strong positioning.

We continue to expect strong earnings next year. Our 2026 target remains unchanged at $6.30 per share, which is at the top end of management's long-term growth range. With demand tailwinds, regulatory support, and a clear capex roadmap, we see strong visibility for sustained earnings and dividend growth moving forward. The utility's $54 billion capital investment plan through 2029 remains a major growth engine, targeting upgrades across transmission, generation, and distribution. Management expects to add 20 GW of new power load through the end of the decade. These trends are primarily being driven by data center buildouts and industrial expansions across key service territories in Ohio and Texas.

The financial foundation remains strong. The company completed a $2.3 billion forward equity offering to meet funding needs through 2029. The utility holds a strong Financial Strength (A) rating, and a top-notch Price Stability (100) score. The dividend yield, which remains a hallmark of AEP's investor appeal, stands at 3.7%. The company continues to target a 60%-70% payout ratio, which supports consistent dividend growth even as capital investments ramp up.

These shares are best suited for conservative and income-oriented investors. The stock is ranked 1 (Highest) for Safety, and the dividend likely remains AEP's most notable feature. The utility's Timeliness rank has been upgraded one notch to 3 (Average) since our last review in early March.

Zachary J. Hodgkinson *June 6, 2025*

(A) Diluted EPS. Excl. nonrec. gains (losses): '10, (7¢); '11, 89¢; '12, (38¢); '13, (14¢); '16, ($2.99); '17, 26¢; '19, (20¢); gain (loss) from disc. ops.: '15, 58¢; '16, (1¢); '22, (58¢); '23, (34¢). Next earnings report due early Aug. **(B)** Div'ds paid early Mar., June, Sept., & Dec. ■ Div'd reinvestment plan avail. † Shareholder invest. plan avail. **(C)** Incl. intang. In '23: $52.5 million **(D)** In mill. **(E)** Rev. may not sum due to rounding.

Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	45
Earnings Predictability	90

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AMEREN NYSE-AEE

RECENT PRICE **96.30** | P/E RATIO **19.5** (Trailing: 20.6 Median: 20.0) | RELATIVE P/E RATIO **1.12** | DIV'D YLD **3.0%** | **VALUE LINE**

TIMELINESS 4 Lowered 5/30/25
SAFETY 1 Raised 9/10/21
TECHNICAL 1 Raised 5/23/25
BETA .80 (1.00 = Market)

18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$69-$115	$92 (-5%)

2028-30 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	145	(+50%)	*13%*
Low	120	(+25%)	*9%*

Institutional Decisions

	2Q2024	3Q2024	4Q2024
to Buy	304	338	399
to Sell	278	269	256
Hld's(000)	215842	239827	240264

High:	48.1	46.8	54.1	64.9	70.9	80.9	87.7	90.8	99.2	91.2	95.7	104.1
Low:	35.2	37.3	41.5	51.4	51.9	63.1	58.7	69.8	73.3	69.7	67.0	86.8

LEGENDS
35.70 x Dividends p sh
Relative Price Strength
Options: Yes
Shaded area indicates recession

Target Price Range 2028 | 2029 | 2030

% TOT. RETURN 5/23/25

	THIS STOCK	VL ARITH.* INDEX
1 yr.	39.1	6.0
3 yr.	13.2	19.2
5 yr.	59.4	95.9

2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	© VALUE LINE PUB. LLC	28-30
29.87	31.77	31.04	28.14	24.06	24.95	25.13	25.04	25.46	25.73	24.00	22.87	24.81	30.37	28.10	128.56	***30.50***	***31.80***	Revenues per sh	***37.00***
6.06	6.33	5.87	5.87	5.25	5.77	6.08	6.59	6.80	7.64	7.83	8.08	8.89	9.59	9.99	10.49	***11.20***	***11.65***	"Cash Flow" per sh	***12.90***
2.78	2.77	2.47	2.41	2.10	2.40	2.38	2.68	2.77	3.32	3.35	3.50	3.84	4.14	4.37	4.59	***4.95***	***5.30***	Earnings per sh [A]	***6.60***
1.54	1.54	1.56	1.60	1.60	1.61	1.66	1.72	1.78	1.85	1.92	2.00	2.20	2.36	2.52	2.68	***2.85***	***3.03***	Div'd Decl'd per sh [B] ■	***3.57***
7.51	4.66	4.50	5.49	5.87	7.66	8.12	8.78	9.05	9.56	9.92	13.02	13.67	12.79	12.87	12.64	***12.80***	***12.85***	Cap'l Spending per sh	***13.00***
33.08	32.15	32.64	27.27	26.97	27.67	28.63	29.27	29.61	31.21	32.73	35.29	37.64	40.11	40.26	42.78	***45.95***	***48.70***	Book Value per sh [C]	***52.65***
237.40	240.40	242.60	242.63	242.63	242.63	242.63	242.63	242.63	244.50	246.20	253.30	257.70	262.00	267.00	266.93	***272.00***	***275.00***	Common Shs Outst'g [D]	***285.00***
9.3	9.7	11.9	13.4	16.5	16.7	17.5	18.3	20.6	18.3	22.1	22.2	21.4	21.5	18.8	17.1	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	***20.0***
.62	.62	.75	.85	.93	.88	.88	.96	1.04	.99	1.18	1.14	1.16	1.24	1.07	.95			Relative P/E Ratio	***1.10***
6.0%	5.8%	5.3%	5.0%	4.6%	4.0%	4.0%	3.5%	3.1%	3.0%	2.6%	2.6%	2.7%	2.7%	3.3%	2.7%			Avg Ann'l Div'd Yield	***3.0%***
6098.0	6076.0	6177.0	6291.0	5910.0	5794.0	6394.0	7957.0	7500.0	7623.0	***8300***	***8750***	Revenues ($mill)	***10550***
585.0	659.0	683.0	821.0	834.0	877.0	995.0	1074.0	1152.0	1182.0	***1345***	***1460***	Net Profit ($mill)	***1880***
38.3%	36.7%	38.2%	22.4%	17.9%	15.0%	13.6%	14.0%	12.0%	12.0%	***12.0%***	***12.0%***	Income Tax Rate	***12.0%***
5.1%	4.1%	5.6%	6.9%	5.8%	5.5%	6.0%	5.0%	6.0%	5.5%	***5.0%***	***5.0%***	AFUDC % to Net Profit	***4.0%***
49.3%	47.7%	49.2%	50.3%	52.1%	55.0%	56.1%	56.6%	55.7%	53.9%	***52.5%***	***52.0%***	Long-Term Debt Ratio	***51.0%***
49.7%	51.3%	49.8%	48.8%	47.1%	44.3%	43.3%	43.4%	43.8%	45.3%	***47.0%***	***47.5%***	Common Equity Ratio	***48.5%***
13968	13840	14420	15632	17116	20158	22391	24193	24847	25432	***26450***	***27100***	Total Capital ($mill)	***29500***
18799	20113	21466	22810	24376	26807	29261	31262	33776	36376	***36300***	***37500***	Net Plant ($mill)	***38400***
5.3%	6.0%	6.0%	6.4%	6.0%	5.3%	5.3%	5.4%	5.5%	5.5%	***5.0%***	***5.0%***	Return on Total Cap'l	***6.0%***
8.3%	9.1%	9.3%	10.6%	10.2%	9.7%	10.1%	10.2%	11.0%	11.0%	***11.0%***	***11.0%***	Return on Shr. Equity	***10.0%***
8.3%	9.2%	9.4%	10.7%	10.3%	9.7%	10.2%	10.2%	11.0%	11.0%	***11.0%***	***11.0%***	Return on Com Equity [E]	***10.0%***
2.5%	3.3%	3.4%	4.8%	4.4%	4.2%	4.4%	4.4%	5.0%	5.0%	***5.0%***	***5.0%***	Retained to Com Eq	***4.0%***
70%	64%	64%	56%	57%	57%	57%	57%	57%	56%	***56%***	***56%***	All Div'ds to Net Prof	***60%***

CAPITAL STRUCTURE as of 3/31/25
Total Debt $19606 mill. **Due in 5 Yrs** $2789 mill.
LT Debt $18354 mill. **LT Interest** $450 mill.
(LT interest earned: 3.8x)
Pension Assets-12/23 $5745 mill.
Oblig $5457 mill.
Pfd Stock $129 mill. **Pfd Div'd** $5 mill.
807,595 sh. $3.50 to $5.50 cum. (no par), $100 stated val., redeem. $102.176-$110/sh.; 487,508 sh. 4.00% to 5.16%, $100 par, redeem. $100-$104.30/sh.
Common Stock 270,278,917 shs.
as of 4/30/25
MARKET CAP: $26.7 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2022	2023	2024
% Change Retail Sales (KWH)	-5.6	+2.1	+3.2
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	NA	NA	NA
Fixed Charge Cov. (%)	291	325	334

ANNUAL RATES

of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '22-'24 to '28-'30
Revenues	-1.5%	.5%	*4.0%*
"Cash Flow"	4.0%	6.5%	*5.5%*
Earnings	4.0%	8.0%	*6.5%*
Dividends	3.5%	5.0%	*6.5%*
Book Value	2.0%	5.5%	*6.5%*

QUARTERLY REVENUES ($ mill.)

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2022	1879	1726	2306	2046	7957
2023	2062	1760	2060	1618	7500
2024	1816	1693	2173	1941	7623
2025	2097	***1850***	***2400***	***1953***	***8300***
2026	***2150***	***1950***	***2450***	***2200***	***8750***

EARNINGS PER SHARE [A]

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2022	.97	.80	1.74	.63	4.14
2023	1.00	.90	1.87	.60	4.37
2024	.98	.97	1.87	.77	4.59
2025	1.07	***1.15***	***1.90***	***.83***	***4.95***
2026	***1.00***	***1.30***	***2.00***	***1.00***	***5.30***

QUARTERLY DIVIDENDS PAID [B] ■

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	.55	.55	.55	.55	2.20
2022	.59	.59	.59	.59	2.36
2023	.63	.63	.63	.63	2.52
2024	.67	.67	.67	.67	2.68
2025	.71				

BUSINESS: Ameren Corporation is a holding company formed through the merger of Union Electric and CIPSCO. Has 1.2 million electric and 127,000 gas customers in Missouri; 1.2 million electric and 813,000 gas customers in Illinois. Discontinued nonregulated power-generation operation in '13. Electric revenue breakdown: residential, 49%; commercial, 34%; industrial, 8%; other, 9%. Generating sources: coal, 73%; nuclear, 11%; hydro & other, 9%; purchased, 7%. Fuel costs: 25% of revenues. Has approximately 9,250 employees. Chairman: Warner L. Baxter. President & CEO: Martin J. Lyons, Jr. Inc.: Missouri. Address: One Ameren Plaza, 1901 Chouteau Ave., P.O. Box 66149, St. Louis, MO 63166-6149. Tel.: 314-621-3222. Internet: www.ameren.com.

Ameren's earnings are on track to rise steadily in 2025. The company posted first-quarter profits of $1.07 per share, which came in ahead of our $1.00 a share estimate, and the $0.98 tally in the year-ago period. Growth was driven by infrastructure investments and colder weather, which boosted retail sales at Ameren Missouri. First-period results were partially offset by higher interest and storm-related expenses, but remain consistent with Ameren's full year target of $4.85-$5.05 per share. Our 2025 profit estimate is staying put at $4.95, the midpoint of that range. Execution across all business segments continues to reflect the strength of Ameren's business and long-term planning.

We remain encouraged by the utility's prospects moving forward. The updated Integrated Resource Plan includes over 1,200 megawatts of new generation, and the company is accelerating investments in solar, natural gas, and storage. Ameren signed construction agreements tied to 2.3 GW of future data center demand, up from 1.8 GW just months ago. A constructive electric rate settlement in Missouri will support near-term returns while keeping rates below regional averages. The company expects a large-load rate structure filing soon. Our 2026 profit forecast is unchanged at $5.30 per share, representing a 7% year-over-year increase. From 2025 through 2029, Ameren sees $63 billion in investment opportunities, backed by 9.2% annual rate base growth.

Dividend growth remains reliable and well supported. Ameren raised its quarterly dividend by 6% in February, now paying $0.71 per share. This marks the second-consecutive year of 6% increases, in line with management's target of 6%-8% annual dividend growth. The current payout ratio sits comfortably within the 55%-70% range. With continued visibility into rate base expansion, dividend growth should remain sustainable well into the next decade.

Although untimely, these shares will likely appeal to conservative accounts. This stock is ranked Highest for Safety. And while the stock yields 3.0%, slightly below the utility group average, it has a strong track record of payouts.

Zachary J. Hodgkinson *June 6, 2025*

(A) Diluted EPS. Excl. nonrec. (losses): '10, ($2.19); '11, (32¢); '12, ($6.42); '17, (63¢); gain (loss) from discontinued ops.: '13, (92¢); '15, 21¢. Next earnings report due early Aug. **(B)** Div'ds paid late Mar., June, Sept., & Dec. ■ Div'd reinvest. plan avail. **(C)** Incl. intang. In '24: $6.60/sh. **(D)** In mill. **(E)** Rate base: Orig. cost depr. Rate allowed on com. eq. in MO in '24: elec. & gas, none specified; in IL: electric, varies; in '24: gas, 9.68%; earned on avg. com. eq., '24: 10.5%.

Company's Financial Strength	A+
Stock's Price Stability	100
Price Growth Persistence	65
Earnings Predictability	100

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DUKE ENERGY NYSE-DUK

RECENT PRICE 120.67 | P/E RATIO 19.0 (Trailing: 20.5 Median: 18.0) | RELATIVE P/E RATIO 1.14 | DIV'D YLD 3.5% | VALUE LINE

TIMELINESS 3 Raised 3/28/25
SAFETY 2 New 6/1/07
TECHNICAL 3 Lowered 2/21/25
BETA .70 (1.00 = Market)

18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$97-$136	$117 (-5%)

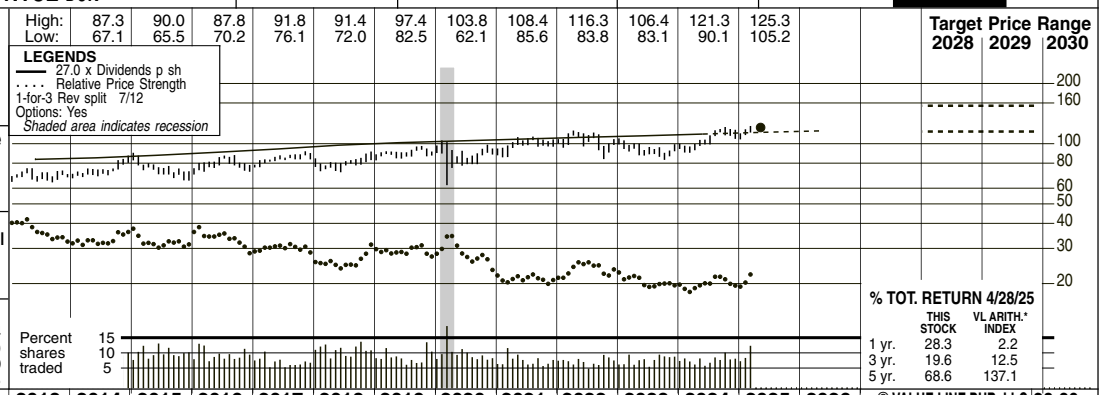
2028-30 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	155	(+30%)	*10%*
Low	115	(-5%)	*3%*

Institutional Decisions

	2Q2024	3Q2024	4Q2024
to Buy	923	984	1119
to Sell	811	849	840
Hld's(000)	507258	578742	575343

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
High:	87.3	90.0	87.8	91.8	91.4	97.4	103.8	108.4	116.3	106.4	121.3	125.3						
Low:	67.1	65.5	70.2	76.1	72.0	82.5	62.1	85.6	83.8	83.1	90.1	105.2						
Revenues per sh	29.18	32.22	32.63	27.88	34.84	33.84	34.10	32.49	33.66	33.73	34.21	31.04	32.64	37.36	37.69	39.12	*40.80*	*42.25*
"Cash Flow" per sh	7.58	8.49	8.68	6.80	8.56	9.11	9.40	9.20	10.01	11.05	12.12	12.04	12.60	12.86	13.45	14.15	*15.00*	*15.75*
Earnings per sh A	3.39	4.02	4.14	3.71	3.98	4.13	4.10	3.71	4.22	4.72	5.06	5.12	5.24	5.27	5.56	5.90	*6.35*	*6.70*
Div'd Decl'd per sh B ■	2.82	2.91	2.97	3.03	3.09	3.15	3.24	3.36	3.49	3.64	3.75	3.82	3.90	3.98	4.06	4.14	*4.22*	*4.30*
Cap'l Spending per sh	9.85	10.84	9.80	7.81	7.83	7.62	9.83	11.29	11.50	12.91	15.17	12.88	12.63	14.76	16.35	15.82	*16.30*	*16.75*
Book Value per sh C	49.85	50.84	51.14	58.04	58.54	57.81	57.74	58.62	59.63	60.27	61.20	59.82	61.55	61.51	61.15	63.34	*65.55*	*68.00*
Common Shs Outst'g D	436.29	442.96	445.29	704.00	706.00	707.00	688.00	700.00	700.00	727.00	733.00	769.00	769.00	770.00	771.00	776.00	*777.00*	*778.00*
Avg Ann'l P/E Ratio	13.3	12.7	13.8	17.5	17.4	17.9	18.2	21.3	19.9	17.0	17.7	17.1	18.9	19.8	16.9	17.8	*Bold figures are Value Line estimates*	
Relative P/E Ratio	.89	.81	.87	1.11	.98	.94	.92	1.12	1.00	.92	.94	.88	1.02	1.14	.94	.94		
Avg Ann'l Div'd Yield	6.2%	5.7%	5.2%	4.7%	4.4%	4.3%	4.3%	4.3%	4.2%	4.5%	4.2%	4.4%	3.9%	3.8%	4.3%	4.0%		
Revenues ($mill)	23459	22743	23565	24521	25079	23868	25097	28768	29060	30357	*31700*	*32900*						
Net Profit ($mill)	2854.0	2560.0	2963.0	3339.0	3747.0	3878.0	4133.0	4166.0	4391.0	4664.0	*5030*	*5325*						
Income Tax Rate	32.2%	31.0%	30.4%	14.1%	12.7%	.3%	5.1%	7.4%	9.2%	11.3%	*11.0%*	*11.0%*						
AFUDC % to Net Profit	9.2%	11.7%	12.3%	11.4%	8.0%	6.9%	5.9%	7.6%	9.1%	9.3%	*9.0%*	*9.0%*						
Long-Term Debt Ratio	48.6%	52.6%	54.0%	53.8%	54.0%	53.7%	55.1%	57.6%	59.6%	60.4%	*61.0%*	*61.0%*						
Common Equity Ratio	51.4%	47.4%	46.0%	46.2%	44.1%	44.4%	43.1%	40.7%	38.8%	38.9%	*38.5%*	*38.5%*						
Total Capital ($mill)	77222	86609	90774	94940	101807	103589	109744	116383	121564	126467	*132375*	*138300*						
Net Plant ($mill)	75709	82520	86391	91694	102127	106782	111408	111748	115315	123303	*129200*	*135200*						
Return on Total Cap'l	4.8%	4.0%	4.3%	4.6%	4.7%	4.8%	4.8%	4.6%	4.9%	5.0%	*5.0%*	*5.0%*						
Return on Shr. Equity	7.2%	6.2%	7.1%	7.6%	8.0%	8.1%	8.4%	8.4%	8.9%	9.3%	*9.5%*	*10.0%*						
Return on Com Equity E	7.2%	6.2%	7.1%	7.6%	8.3%	8.2%	8.5%	8.6%	9.1%	9.3%	*9.5%*	*10.0%*						
Retained to Com Eq	1.5%	.6%	1.2%	2.0%	2.4%	2.3%	1.9%	2.1%	2.4%	2.7%	*3.0%*	*3.5%*						
All Div'ds to Net Prof	79%	91%	83%	74%	71%	73%	78%	76%	74%	71%	*67%*	*65%*						



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CAPITAL STRUCTURE as of 12/31/24
Total Debt $84273 mill. **Due in 5 Yrs** $21264 mill.
LT Debt $76340 mill. **LT Interest** $3384 mill.
Incl. $524 mill. finance leases.
(Total Interest Coverage: 2.5x)
Leases, Uncapitalized Annual rentals $256 mill.
Pension Assets-12/24 $6887 mill.
Oblig. $5980 mill.
Pfd Stock $973 mill. **Pfd Div'd** $106 mill.

Common Stock 776,461,008 shs.
as of 1/31/25

MARKET CAP: $93.7 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2022	2023	2024
% Change Retail Sales (GWH)	+4.5%	-4.7%	+2.9%
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (avg.)	+1.8%	+1.7	+1.8%
Fixed Charge Cov. (%)	229	223	226

ANNUAL RATES of change (per sh)

	Past 10 Yrs.	Past 5 Yrs.	Est'd '22-'24 to '28-'30
Revenues	1.5%	2.5%	*3.5%*
"Cash Flow"	5.0%	4.0%	*5.5%*
Earnings	3.5%	3.5%	*6.0%*
Dividends	3.0%	2.5%	*3.5%*
Book Value	.5%	.5%	*3.5%*

Calendar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2022	7132	6685	7968	6983	28768
2023	7276	6578	7994	7212	29060
2024	7671	7172	8154	7360	30357
2025	*8075*	*7250*	*8475*	*7900*	*31700*
2026	*8375*	*7525*	*8800*	*8200*	*32900*

Calendar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2022	1.29	1.09	1.78	1.11	5.27
2023	1.20	.91	1.94	1.51	5.56
2024	1.44	1.18	1.62	1.66	5.90
2025	*1.55*	*1.25*	*1.85*	*1.70*	*6.35*
2026	*1.65*	*1.30*	*1.95*	*1.80*	*6.70*

Calendar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	.965	.965	.985	.985	3.90
2022	.985	.985	1.005	1.005	3.98
2023	1.005	1.005	1.025	1.025	4.06
2024	1.025	1.025	1.045	1.045	4.14
2025	1.045				

BUSINESS: Duke Energy Corporation is a holding company for utilities with 8.4 mill. elec. customers in NC, FL, IN, SC, OH, and KY, and 1.7 mill. gas customers in OH, KY, NC, SC, and TN. Owns independent power plants & has 17.5% stake in National Methanol in Saudi Arabia. Acq'd Progress Energy 7/12; Piedmont Natural Gas 10/16; discontinued most int'l ops. in '16. Electric revenue breakdown: residential, 34%; commercial, 31%; industrial, 18%; other, 17%. Generating sources: gas, 35%; nuclear, 27%; coal, 14%; other, 2%; purchased, 22%. Fuel costs: 32% of revs. '24 reported deprec. rate: 3.0%. Has 26,400 employees. Chairman: Ted Craver CEO: Harry Sideris. Inc.: DE. Addr.: 525 South Tryon St., Charlotte, NC 28202-1803. Tel.: 800-488-3853. Int.: www.duke-energy.com.

We're looking for solid intermediate-term results from Duke Energy to continue. We think this year and next may well mark the ninth- and tenth-consecutive years of higher annual core operating earnings gains. The utility is likely to continue to benefit from solid weather-adjusted electric volume growth and constructive regulatory outcomes. Good population growth in Duke's service areas, at two to four times the national average of 0.5%, is a key part of the story. This is largely being driven by healthy migration trends to the Carolinas and Florida, where a generally lower cost of living and the temperate coastal climate are draws. The company is also likely to keep benefiting from rate relief (higher regulated price adjustments) as discussed below. Leadership has introduced its 2025 adjusted earnings-per-share target of $6.17-$6.42 and extended its long-term bottom-line growth rate of 5%-7% per annum through 2029 off of the $6.30 midpoint of this year's range.

The company has been successful on the regulatory front of late. Florida officials approved a $203 million revenue increase this year and $59 million more in 2026. Up to $141 million for 12 new solar plants was approved to be paid out as they are completed. The settlement dictates that Duke uses roughly $50 million in federal tax credits to offset the need for a rate hike in 2027. Meanwhile, the final order in Duke's South Carolina regulatory decision became effective in August of last year and will increase electric delivery rates by 13% over a two-year span from then. The decision includes $215 million of new investments in highly efficient natural gas, solar, nuclear, and hydroelectric units over a seven-year period. Prices in North Carolina recently increased by 2.9%, and Indiana rates were lifted by 8.0%. An Ohio regulatory decision is pending.

Duke stock has outperformed the peer group so far this year. Utilities tend to do well when the economy appears to be on shaky ground. A flight to quality large-cap, low-risk plays within the group has DUK's share price up 12% year to date and 22% over the past 12 months. As a result, much of the earnings growth we're projecting is already baked in, leading to below-average total return potential.

Anthony J. Glennon *May 9, 2025*

(A) Dil. EPS. Excl. net nonrec. losses: '12, 64¢; '13, 22¢; '14, 59¢; '15, 5¢; '16, 60¢; '18, 96; '20, $3.40; '21, 30¢; '22, $2.10; '23, $2.02; '24, 19¢; net nonrec. gain: '17, 14¢. Qtly. EPS may not sum to annual due to rounding. Next egs. due early Aug. **(B)** Div'ds paid mid-Mar., June, Sept., & Dec. ■ Div'd reinv. plan avail. **(C)** Incl. intang. In '24: $43.24/sh. **(D)** In mill., **(E)** Rate base: Net orig. cost. Rate all'd on com. eq. in '24 in NC: 9.94%; in '24 in FL: 9.3%-11.3%; in '20 in IN: 9.7%. in '24 in SC: 9.94%; Reg. Clim.: FL, NC, SC Avg.; OH, IN Above Avg.

Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	45
Earnings Predictability	100

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EDISON INTERNAT'L NYSE-EIX

RECENT PRICE 50.51 | P/E RATIO 8.4 (Trailing: 9.8 Median: 15.0) | RELATIVE P/E RATIO 0.45 | DIV'D YLD 6.9% | VALUE LINE

TIMELINESS 3 Raised 5/2/25
SAFETY 3 Lowered 4/18/25
TECHNICAL 3 Raised 6/20/25
BETA .90 (1.00 = Market)

18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$49-$109	$79 (55%)

2028-30 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	110	(+120%)	*25%*
Low	75	(+50%)	*15%*

Institutional Decisions

	3Q2024	4Q2024	1Q2025
to Buy	454	458	470
to Sell	325	358	441
Hld's(000)	379213	381923	335433

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
High:	68.7	69.6	78.7	83.4	71.0	76.4	78.9	68.6	73.3	74.9	88.8	81.0						
Low:	44.7	55.2	58.0	62.7	45.5	53.4	43.6	53.9	54.4	58.8	63.2	47.7						

LEGENDS
21.7 x Dividends p sh
Relative Price Strength
Options: Yes
Shaded area indicates recession

Target Price Range 2028 2029 2030

% TOT. RETURN 7/7/25

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-25.8	14.6
3 yr.	-7.3	44.6
5 yr.	16.6	96.9

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37.98	38.09	39.16	36.41	38.61	41.17	35.37	36.43	37.81	38.85	34.11	35.83	39.18	45.05	42.56	45.74	***46.70***	***48.35***
7.96	8.41	9.03	9.63	8.80	9.95	10.35	10.43	11.03	4.69	9.39	9.80	10.59	11.51	11.80	12.59	***14.10***	***14.45***
3.24	3.35	3.23	4.55	3.78	4.33	4.15	3.94	4.51	d1.26	4.70	4.52	4.59	4.63	4.76	4.91	***6.00***	***6.15***
1.25	1.27	1.29	1.31	1.37	1.48	1.73	1.98	2.23	2.43	2.48	2.58	2.69	2.84	2.99	3.17	***3.36***	***3.56***
10.07	13.94	14.76	12.73	11.05	11.99	12.97	11.46	11.75	13.84	13.47	14.47	14.47	15.12	14.19	14.83	***16.25***	***16.75***
30.20	32.44	30.86	28.95	30.50	33.64	34.89	36.82	35.82	32.10	36.75	37.08	36.57	35.70	36.02	36.18	***39.00***	***41.85***
325.81	325.81	325.81	325.81	325.81	325.81	325.81	325.81	325.81	325.81	361.99	378.91	380.38	382.21	383.93	384.78	***387.00***	***389.00***
9.7	10.3	11.8	9.7	12.7	13.0	14.8	17.9	17.2	--	14.1	13.3	12.9	14.0	14.4	15.6		
.65	.66	.74	.62	.71	.68	.75	.94	.87	--	.75	.68	.70	.81	.80	.83		
4.0%	3.7%	3.4%	3.0%	2.8%	2.6%	2.8%	2.8%	2.9%	3.8%	3.7%	4.3%	4.5%	4.4%	4.4%	4.1%		
11524	11869	12320	12657	12347	13578	14905	17220	16338	17599	***18070***	***18800***
1480.0	1422.0	1603.0	d290.0	1716.0	1818.0	1907.0	1977.0	2035.0	2162.0	***2575***	***2650***
6.6%	11.1%	5.0%	--	1.2%	5.0%	18.0%	12.5%	14.9%	10.6%	***13.0%***	***13.0%***
8.0%	6.8%	7.2%	--	9.6%	9.6%	8.8%	9.6%	11.4%	12.4%	***11.0%***	***11.0%***
45.0%	41.8%	45.6%	53.6%	53.5%	55.2%	57.6%	60.7%	62.8%	65.4%	***65.5%***	***65.5%***
46.7%	49.2%	45.8%	38.3%	39.9%	39.5%	33.2%	30.6%	28.7%	27.1%	***27.5%***	***28.0%***
24352	24362	25506	27284	33360	35581	41959	44547	48260	51274	***54675***	***58200***
35085	37000	39050	41348	44285	47839	50700	53486	56084	59254	***62400***	***65700***
7.1%	6.9%	7.3%	.1%	6.4%	6.3%	5.6%	5.7%	5.8%	6.0%	***6.0%***	***6.0%***
11.1%	10.0%	11.6%	NMF	11.1%	11.4%	10.7%	11.3%	11.3%	12.2%	***13.5%***	***13.0%***
12.0%	10.8%	12.7%	NMF	12.0%	12.0%	12.5%	12.9%	13.1%	13.7%	***14.5%***	***14.0%***
7.2%	5.6%	6.6%	NMF	5.9%	5.4%	5.4%	5.2%	5.0%	5.1%	***5.5%***	***5.5%***
44%	53%	52%	NMF	54%	58%	61%	64%	66%	67%	***61%***	***62%***

Bold figures are Value Line estimates

	28-30
Revenues per sh	***55.70***
"Cash Flow" per sh	***15.35***
Earnings per sh A	***7.00***
Div'd Decl'd per sh B ■	***4.15***
Cap'l Spending per sh	***17.00***
Book Value per sh C	***50.00***
Common Shs Outst'g D	***395.00***
Avg Ann'l P/E Ratio	***13.0***
Relative P/E Ratio	***.70***
Avg Ann'l Div'd Yield	***4.6%***
Revenues ($mill)	***22000***
Net Profit ($mill)	***3020***
Income Tax Rate	***13.0%***
AFUDC % to Net Profit	***11.0%***
Long-Term Debt Ratio	***65.0%***
Common Equity Ratio	***29.0%***
Total Capital ($mill)	***69000***
Net Plant ($mill)	***75700***
Return on Total Cap'l	***5.5%***
Return on Shr. Equity	***13.0%***
Return on Com Equity E	***14.0%***
Retained to Com Eq	***5.0%***
All Div'ds to Net Prof	***63%***

CAPITAL STRUCTURE as of 3/31/25
Total Debt $38391 mill. **Due in 5 Yrs** $12755 mill.
LT Debt $35387 mill. **LT Interest** $1815 mill.
(Total Interest Coverage: 2.2x)
Leases, Uncapitalized Annual rentals $170 mill.

Pension Assets-12/24 $3608 mill.
Oblig. $3636 mill.

Pfd Stock $3820 mill. **Pfd Div'd** $262 mill.

Common Stock 384,763,662 shs.
as of 4/22/25
MARKET CAP: $19.4 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2022	2023	2024
% Change Retail Sales (KWH)	+.9	-6.3	+3.3
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	24345	21254	23861
Annual Load Factor (%)	45.8	49.7	43.6
% Change Customers (yr-end)	+.8	+.7	+.8
Fixed Charge Cov. (%)	135	166	153

ANNUAL RATES of change (per sh)

	Past 10 Yrs.	Past 5 Yrs.	Est'd '22-'24 to '28-'30
Revenues	1.5%	4.0%	*4.0%*
"Cash Flow"	2.5%	7.5%	*4.0%*
Earnings	1.0%	12.5%	*6.5%*
Dividends	8.0%	4.5%	*5.5%*
Book Value	1.5%	.5%	*6.0%*

QUARTERLY REVENUES ($ mill.)

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2022	3968	4008	5228	4016	17220
2023	3966	3964	4702	3706	16338
2024	4078	4336	5201	3984	17599
2025	3811	***4529***	***5450***	***4280***	***18070***
2026	***4050***	***4710***	***5700***	***4340***	***18800***

EARNINGS PER SHARE A

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2022	1.07	.94	1.48	1.15	4.63
2023	1.09	1.01	1.38	1.28	4.76
2024	1.13	1.23	1.50	1.05	4.91
2025	1.37	***1.40***	***1.80***	***1.43***	***6.00***
2026	***1.40***	***1.40***	***1.85***	***1.50***	***6.15***

QUARTERLY DIVIDENDS PAID B ■

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	.6625	.6625	.6625	.6625	2.65
2022	.70	.70	.70	.70	2.80
2023	.7375	.7375	.7375	.7375	2.95
2024	.78	.78	.78	.78	3.12
2025	.8275	.8275			

BUSINESS: Edison International is a holding company for Southern California Edison Company (SoCal Edison), which supplies electricity to 5.28 mill. customers in a 50,000 sq. mi. area in central, coastal, & southern CA (excl. Los Angeles & San Diego). Edison Energy is an energy svcs. co. Disc. Edison Mission Energy (independent power producer) in '12. Elec. rev. breakdown: residential, 40%; commercial, 43%; industrial, 3%; other, 14%. Generating sources: nuclear, 9%; gas, 5%; hydroelectric, 6%; purchased, 80%. Power costs: 34% of revs. '24 reported depr. rate: 4.1%. Employs 13,500. Board Chair: Peter J. Taylor. President & CEO: Pedro J. Pizzaro. Inc.: CA. Address: 2244 Walnut Grove Ave., P.O. Box 976, Rosemead, CA 91770. Tel.: 626-302-2222. Internet: www.edison.com.

Edison International is being sued for allegedly igniting the Eaton Fire, one of the two more destructive blazes that rampaged through Los Angeles County in January. Lawsuits have been filed against the company by firms representing residents, shareholders, insurers, the county, and the cities of Pasadena and Sierra Madre. While investigations are ongoing, the utility's equipment is being thoroughly considered as a potential ignition source of the wildfire. The company has acknowledged a possible link, but has not determined a definitive cause yet. The origin of the similarly destructive Palisades Fire began outside of Edison's service area, but it has still been named in lawsuits related to that blaze. The Eaton Fire destroyed over 9,400 structures and resulted in 18 fatalities, while the Palisades Fire wrecked more than 6,800 structures and led to 12 deaths. Combined, tens of thousands of acres were burned and significant public infrastructure was ruined. Property damages alone are estimated to be as high as $55 billion. It may take several more months before authorities' investigations conclude.

The California Wildfire Fund of 2019 (CWF) will probably limit Edison's potential liability. The CWF serves as self insurance for the state's three major utilities. It was funded by the companies and their customers and contains $21 billion. Under most circumstances the CWF would prevent utilities from suffering major material losses beyond the first $1 billion of damages per incident, which is like a deductible and is not covered. Hence, even if EIX's equipment is found to be at fault for the Eaton Fire and possibly the smaller Hurst blaze, $2 billion would not be too problematic for the company's balance sheet. It pales in comparison to the $11 billion in market capitalization lost since early January. The problem is this exercise may not be as straightforward as that. There are uncertainties. The CWF does not fully cover negligence. Also, the CWF is likely to be largely depleted and will need to be replenished. There is no predefined mechanism for that.

This stock is not timely. Sentiment may remain poor for quite a while, with ongoing headline risk a factor to consider.

Anthony J. Glennon *July 18, 2025*

(A) Adj. (non-GAAP) EPS from 2019 on. Excl. gains/(losses): nonrecur's ; '10, 54¢; '11, ($3.33); '13, ($1.12); '15, ($1.18); '17, ($1.37); '18, (14¢); '19, (92¢); '20, ($2.54); '21, ($2.59); '22, ($3.02); '23, ($1.34); '24, ($1.60); disc. ops.: '13, 11¢; '14, 57¢; '15, 11¢; '18, 10¢. Qtly. EPS may not sum to full yr. due to rounding. Next egs. report due late July. **(B)** Div'ds paid late Jan., Apr., July, & Oct. ■ Div'd reinv. plan avl. **(C)** Incl. def'd chgs. In '24: $4.40/sh. **(D)** In mill. **(E)** Rate base: net orig. cost. Rate all'd on com. eq. in '25: 10.33%; Reg Clmt Avg.

Company's Financial Strength	B+
Stock's Price Stability	25
Price Growth Persistence	20
Earnings Predictability	15

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ENTERGY CORP. NYSE-ETR

RECENT PRICE **82.82** | P/E RATIO **24.4** (Trailing: 26.8 Median: 15.0) | RELATIVE P/E RATIO **1.40** | DIV'D YLD **2.9%** | **VALUE LINE**

TIMELINESS 3 Raised 8/16/24
SAFETY 1 Raised 9/6/24
TECHNICAL 1 Raised 5/23/25
BETA .80 (1.00 = Market)

18-Month Target Price Range

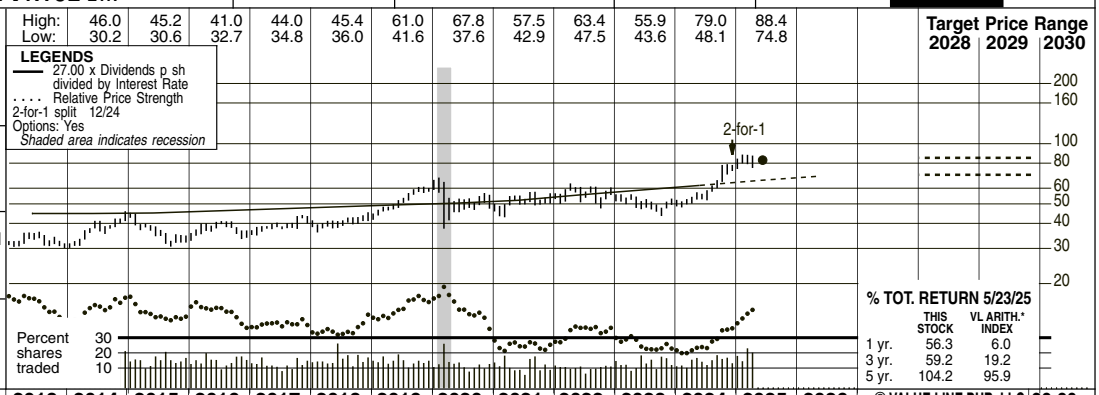
Low-High	Midpoint (% to Mid)
$74-$105	$90 (10%)

2028-30 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	85	(+5%)	*4%*
Low	70	(-15%)	*Nil*

Institutional Decisions

	2Q2024	3Q2024	4Q2024
to Buy	496	500	1001
to Sell	333	382	130
Hld's(000)	391478	442178	425546



2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	© VALUE LINE PUB. LLC	28-30
28.41	32.13	31.84	28.97	31.93	34.86	32.27	30.27	30.67	29.12	27.31	25.25	28.97	32.59	28.54	27.65	*28.75*	*30.00*	Revenues per sh	*33.25*
6.64	8.27	8.77	7.99	8.12	8.84	8.85	9.36	8.35	8.25	8.60	9.10	8.95	7.75	10.77	8.10	*8.80*	*9.30*	"Cash Flow" per sh	*10.50*
3.15	3.33	3.78	3.01	2.48	2.89	2.91	3.44	2.60	2.94	3.15	3.45	3.44	2.69	5.55	2.45	*3.35*	*3.60*	Earnings per sh A	*4.20*
1.50	1.62	1.66	1.66	1.66	1.66	1.67	1.71	1.75	1.79	1.83	1.87	1.93	2.05	2.17	2.30	*2.43*	*2.55*	Div'd Decl'd per sh B ■ †	*3.00*
6.50	6.66	7.60	9.09	7.86	7.41	8.39	8.64	11.04	11.23	10.86	12.26	15.43	12.52	10.43	11.26	*12.00*	*12.50*	Cap'l Spending per sh	*14.00*
22.77	23.77	25.41	25.86	27.00	27.92	25.95	22.56	22.14	23.39	25.67	27.28	28.71	30.70	34.35	35.11	*36.50*	*38.25*	Book Value per sh C	*43.45*
378.24	357.49	352.71	355.62	356.74	358.48	356.78	358.26	361.04	378.11	398.30	400.49	405.31	422.35	425.70	429.58	*435.00*	*440.00*	Common Shs Outst'g D	*460.00*
12.0	11.6	9.1	11.2	13.2	12.9	12.5	10.9	15.0	13.8	16.5	15.3	15.0	21.1	9.1	24.1	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	*18.0*
.80	.74	.57	.71	.74	.68	.63	.57	.75	.75	.88	.79	.81	1.22	.51	1.27			Relative P/E Ratio	*1.00*
4.0%	4.2%	4.9%	4.9%	5.1%	4.5%	4.6%	4.6%	4.5%	4.4%	3.5%	3.6%	3.7%	3.6%	4.3%	3.9%			Avg Ann'l Div'd Yield	*3.7%*
11513	10846	11074	11009	10879	10114	11743	13764	12147	11880	*12500*	*13200*	Revenues ($mill)	*15300*
1061.2	1249.8	950.7	1092.1	1258.2	1406.7	1402.8	1103.2	2356.5	1055.6	*1455*	*1585*	Net Profit ($mill)	*1930*
2.2%	11.3%	1.8%	--	--	--	16.1%	--	16.1%	26.4%	*20.0%*	*20.0%*	Income Tax Rate	*23.0%*
7.4%	8.1%	14.7%	17.5%	16.7%	12.2%	7.1%	2.5%	1.7%	5.0%	*2.0%*	*2.0%*	AFUDC % to Net Profit	*2.0%*
57.8%	63.6%	63.6%	63.2%	62.0%	65.5%	67.6%	64.2%	60.8%	63.5%	*63.5%*	*63.5%*	Long-Term Debt Ratio	*63.5%*
40.8%	35.5%	35.5%	35.9%	37.1%	33.7%	31.7%	35.2%	38.6%	36.0%	*36.5%*	*36.5%*	Common Equity Ratio	*36.5%*
22714	22777	22528	24602	27557	32386	36733	36810	37851	41917	*44330*	*46985*	Total Capital ($mill)	*55915*
27824	27921	29664	31974	35183	38853	42244	42477	43834	47423	*50270*	*53285*	Net Plant ($mill)	*63460*
6.0%	6.9%	5.7%	5.8%	5.9%	5.6%	4.9%	4.3%	7.6%	4.0%	*4.5%*	*4.5%*	Return on Total Cap'l	*4.5%*
11.1%	15.1%	11.6%	12.0%	12.0%	12.6%	11.8%	8.4%	15.9%	6.9%	*9.0%*	*9.5%*	Return on Shr. Equity	*9.5%*
11.2%	15.2%	11.7%	12.2%	12.1%	12.7%	11.9%	8.4%	16.0%	6.9%	*9.0%*	*9.5%*	Return on Com Equity E	*9.5%*
4.8%	7.7%	3.9%	4.9%	5.2%	5.9%	5.2%	1.9%	9.7%	.4%	*2.5%*	*2.5%*	Retained to Com Eq	*2.5%*
58%	50%	68%	61%	58%	55%	57%	78%	40%	95%	*73%*	*71%*	All Div'ds to Net Prof	*71%*

CAPITAL STRUCTURE as of 3/31/25
Total Debt $30925 mill. **Due in 5 Yrs** $11117 mill.
LT Debt $28265 mill. **LT Interest** $1046.0 mill.
Incl. $54.7 mill. of securitization bonds.
(LT interest earned: 2.2x)
Leases, Uncapitalized Annual rentals $198.8 mill.
Pension Assets-12/24 $4432.7 mill.
Oblig $4,520.7 mill.
Pfd Stock $219.4 mill. **Pfd Div'd** $18.3 mill.
200,000 shs. 6.25%-7.5%, $100 par; 250,000 shs. 8.75%, 1.4 mill. shs. 5.375%; all cum., without sinking fund.
Common Stock 430,774,109 shs. **as of 3/31/25**
MARKET CAP: $35.7 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2022	2023	2024
% Change Retail Sales (KWH)	+1.1	+4.5	-1.0
Total Indust. Use (GWH)	52501	52807	57081
Avg. Indust. Revs. per KWH(¢)	7.08	6.00	5.60
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+1.0	+.4	+.7
Fixed Charge Cov. (%)	209	250	220

ANNUAL RATES of change (per sh)

	Past 10 Yrs.	Past 5 Yrs.	Est'd '22-'24 to '28-'30
Revenues	-1.0%	.5%	*2.0%*
"Cash Flow"	.5%	1.0%	*3.0%*
Earnings	2.5%	4.0%	*3.0%*
Dividends	2.5%	4.0%	*5.5%*
Book Value	2.0%	7.0%	*4.5%*

QUARTERLY REVENUES ($ mill.)

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2022	2878	3395	4219	3273	13764
2023	2981	2846	3596	2725	12147
2024	2795	2954	3389	2742	11880
2025	2849	*3300*	*3200*	*3151*	*12500*
2026	*3100*	*3400*	*3400*	*3300*	*13200*

EARNINGS PER SHARE A

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2022	.68	.39	1.37	.26	2.69
2023	.74	.92	1.57	2.33	5.55
2024	.18	.12	1.50	.65	2.45
2025	.82	*.20*	*1.63*	*.70*	*3.35*
2026	*.70*	*.45*	*1.70*	*.75*	*3.60*

QUARTERLY DIVIDENDS PAID B ■ †

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	.475	.475	.475	.505	1.93
2022	.505	.505	.505	.535	2.05
2023	.535	.535	.535	.565	2.17
2024	.565	.565	.565	.60	2.30
2025	.60	.60			

BUSINESS: Entergy Corporation supplies electricity to 3 million customers through subsidiaries in Arkansas, Louisiana, Mississippi, Texas, and New Orleans (regulated separately from Louisiana). Distributes gas to 206,000 customers in Louisiana. Is selling its last nonutility nuclear unit (shut down 5/22). Electric revenue breakdown: residential, 37%; commercial, 24%; industrial, 27%; other, 12%. Generating sources: gas, 68%; nuclear, 22%; coal, 9%; hydro and solar, 1%. Fuel costs: 32% of revenues. '24 reported depreciation rate: 2.8%. Has 11,707 employees. Chairman & CEO: Leo P. Denault. Incorporated: Delaware. Address: 639 Loyola Avenue, P.O. Box 61000, New Orleans, Louisiana 70161. Telephone: 504-576-4000. Internet: www.entergy.com.

Entergy reported a decent improvement in its first-quarter results. Revenues expanded 2% year over year to $2.849 billion, as the company delivered 13% more residential usage in its coverage area during the quarter. This benefited from cooler weather across the area. Costs related to energy generation declined considerably as Entergy purchased less fuel, while Entergy recorded higher costs due to growth in its capital structure. Interest costs rose due to a greater debt load. Even so, these factors netted a gain of $0.82 per share during the quarter.

The company remains on track to deliver a solid performance for the remainder of the year. A few major projects are expected to come online, while we anticipate continued demand from the residential sector as more consumers move into the coverage area. However, Entergy received approval to sell its local distribution companies in the Louisiana coverage area, which may be a headwind. Cost growth will likely occur at a steady pace, while we expect interest costs to rise due to a large-scale capital buildout financed by debt. All told, we estimate that earnings per share will be $3.35 in 2025.

Long-term expansion is likely to benefit from several trends. The company has continued to win new industrial customers, including a recently announced low-carbon blue ammonia facility from CF Industries, as well as a manufacturing plant in the company's Louisiana territory, announced by Hyundai Motor Group. Other industrial activities are likely to occur, helping to boost demand, especially as these plants hire new workers, which in turn will stimulate residential usage. We expect growth in data centers to occur, thereby furthering demand, but interest expenses should rise. Greater infrastructure buildouts in the years ahead will lead to increased administrative and maintenance expenses. All told, we think that earnings per share will advance to $3.60 in 2026 and $4.20 by 2028-2030.

Shares of Entergy are neutrally ranked for Timeliness. The stock holds unimpressive 3- to 5-year appreciation potential. However, the dividend yield is above average. Thus, we believe this equity is best suited for income seekers.

John E. Seibert III *June 6, 2025*

(A) Diluted EPS. GAAP starting in 2022. Excl. nonrec. losses: '12, $1.26; '13, $1.14; '14, 56¢; '15, $6.99; '16, $10.14; '17, $2.91; '18, $1.25; '21, $1.33. Next earnings report due early August. **(B)** Div'ds historically paid in early Mar., June, Sept., & Dec. ■ Div'd reinvestment plan avail. † Shareholder investment plan avail. **(C)** Incl. deferred charges. In '24: $14.92/sh. **(D)** In mill. **(E)** Rate base: Net original cost. Allowed ROE (blended): 9.79%; earned on avg. com. eq., '24: 6.9%. Regulatory Climate: Average.

Company's Financial Strength	A+
Stock's Price Stability	95
Price Growth Persistence	55
Earnings Predictability	60

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EVERGY, INC. NYSE-EVRG

RECENT PRICE 65.80 | P/E RATIO 16.2 (Trailing: 17.3 Median: NMF) | RELATIVE P/E RATIO 0.93 | DIV'D YLD 4.1% | VALUE LINE

TIMELINESS 4 Lowered 5/30/25
SAFETY 2 New 9/14/18
TECHNICAL 1 Raised 6/6/25
BETA .75 (1.00 = Market)

18-Month Target Price Range

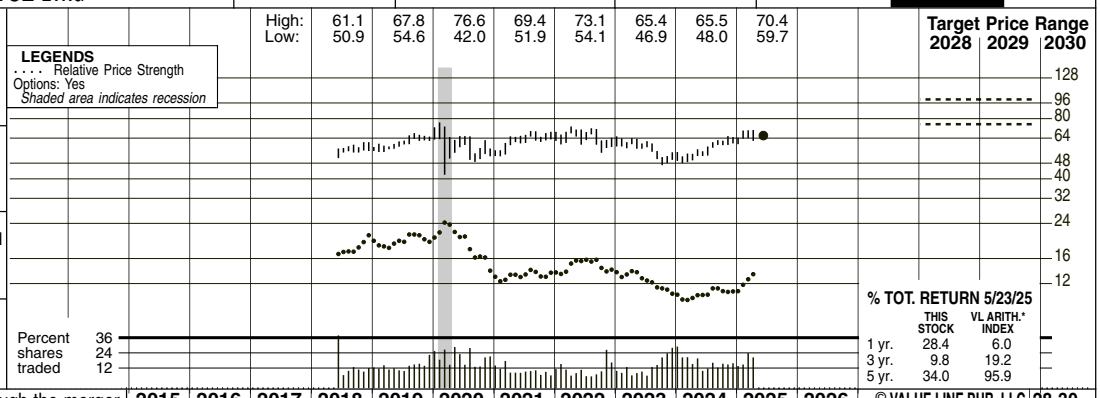
Low-High	Midpoint (% to Mid)
$48-$77	$63 (-5%)

2028-30 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	100	(+50%)	*14%*
Low	75	(+15%)	*7%*

Institutional Decisions

	2Q2024	3Q2024	4Q2024
to Buy	344	339	402
to Sell	291	293	288
Hld's(000)	197848	222197	223093



Evergy, Inc. was formed through the merger of Great Plains Energy and Westar Energy in June of 2018. Great Plains Energy holders received .5981 of a share of Evergy for each of their shares, and Westar Energy holders received one share of Evergy for each of their shares. The merger was completed on June 4, 2018. Shares of Evergy began trading on the New York Stock Exchange one day later.

CAPITAL STRUCTURE as of 3/31/25
Total Debt $13058 mill. **Due in 5 Yrs** $4388 mill.
LT Debt $12406 mill. **LT Interest** $306 mill.
Incl. $40.9 mill. finance leases.
(LT interest earned: 3.8x)

Leases, Uncapitalized Annual rentals $18.8 mill.

Pension Assets-12/24 $1714.7 mill.
Oblig $2561.7 mill.
Pfd Stock None

Common Stock 230,090,698 shs.
MARKET CAP: $15.7 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2022	2023	2024
% Change Retail Sales (KWH)	-3.9	+3.1	+6.7
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	7.14	6.94	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	NA	NA	NA
Fixed Charge Cov. (%)	286	350	382

ANNUAL RATES of change (per sh)

	Past 10 Yrs.	Past 5 Yrs.	Est'd '22-'24 to '28-'30
Revenues	--	--	*2.5%*
"Cash Flow"	--	--	*5.0%*
Earnings	--	--	*7.5%*
Dividends	--	--	*7.0%*
Book Value	--	--	*3.5%*

QUARTERLY REVENUES ($ mill.)

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2022	1223.9	1446.5	1909.1	1279.6	5859.1
2023	1296.8	1354.2	1669.3	1187.9	5508.2
2024	1331.0	1447.5	1811.4	1257.4	5847.3
2025	1374.5	*1460*	*1840*	*1325.5*	*6000*
2026	*1400*	*1500*	*1950*	*1400*	*6250*

EARNINGS PER SHARE A

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2022	.53	.84	1.86	.03	3.26
2023	.62	.78	1.53	.24	3.17
2024	.53	.90	2.02	.35	3.80
2025	.54	*.95*	*2.00*	*.56*	*4.05*
2026	*.70*	*1.00*	*2.05*	*.50*	*4.25*

QUARTERLY DIVIDENDS PAID B ■

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	.535	.535	.535	.5725	2.18
2022	.5725	.5725	.5725	.6125	2.33
2023	.6125	.6125	.6125	.6425	2.48
2024	.6425	.6425	.6425	.6675	2.60
2025	.6675				

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	© VALUE LINE PUB. LLC	28-30
	--	--	--	16.75	22.71	21.66	24.36	25.49	23.98	25.43	*26.10*	*27.15*	Revenues per sh	*32.15*
	--	--	--	4.89	7.18	7.06	8.18	7.34	8.33	8.64	*8.55*	*8.85*	"Cash Flow" per sh	*9.65*
	--	--	--	2.50	2.79	2.72	3.83	3.26	3.17	3.80	*4.05*	*4.25*	Earnings per sh A	*5.05*
	--	--	--	1.74	1.93	2.05	2.18	2.33	2.48	2.60	*2.71*	*2.84*	Div'd Decl'd per sh B ■	*3.25*
	--	--	--	4.19	5.34	6.88	8.60	9.41	9.23	9.26	*9.30*	*9.35*	Cap'l Spending per sh	*9.50*
	--	--	--	39.28	37.82	38.50	40.32	41.86	42.06	43.43	*45.65*	*45.85*	Book Value per sh C	*47.50*
	--	--	--	255.33	226.64	226.84	229.30	229.90	229.73	229.98	*230.00*	*230.00*	Common Shs Outst'g D	*230.00*
	--	--	--	22.7	21.8	21.7	16.2	19.9	18.0	14.8	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	*17.5*
	--	--	--	1.23	1.16	1.11	.88	1.15	1.01	.82			Relative P/E Ratio	*.95*
	--	--	--	3.1%	3.2%	3.5%	3.5%	4.0%	5.1%	4.0%			Avg Ann'l Div'd Yield	*3.7%*
	--	--	--	4275.9	5147.8	4913.4	5586.7	5859.1	5508.2	5847.3	*6000*	*6250*	Revenues ($mill)	*7400*
	--	--	--	535.8	669.9	618.3	879.7	752.7	731.3	873.5	*930*	*980*	Net Profit ($mill)	*1160*
	--	--	--	9.8%	12.6%	14.1%	11.7%	5.8%	2.1%	3.3%	*6.5%*	*7.5%*	Income Tax Rate	*9.0%*
	--	--	--	2.5%	2.5%	5.5%	5.0%	5.1%	5.4%	5.8%	*6.0%*	*6.0%*	AFUDC % to Net Profit	*5.0%*
	--	--	--	40.0%	50.6%	51.3%	50.1%	50.0%	51.5%	*51.5%*	*52.0%*	*52.5%*	Long-Term Debt Ratio	*53.5%*
	--	--	--	60.0%	49.4%	48.7%	49.9%	48.0%	48.0%	*48.5%*	*48.0%*	*47.5%*	Common Equity Ratio	*46.5%*
	--	--	--	16716	17337	17924	18542	19668	20019	*21250*	*22500*	*22750*	Total Capital ($mill)	*23400*
	--	--	--	18952	19346	20106	21150	22277	23729	*24200*	*25300*	*25600*	Net Plant ($mill)	*26300*
	--	--	--	4.0%	4.8%	4.5%	5.7%	6.9%	6.4%	*5.5%*	*5.5%*	*5.5%*	Return on Total Cap'l	*6.0%*
	--	--	--	5.3%	7.8%	7.1%	9.5%	8.1%	7.6%	*9.0%*	*9.0%*	*9.0%*	Return on Shr. Equity	*10.0%*
	--	--	--	5.3%	7.8%	7.1%	9.5%	8.1%	7.6%	*9.0%*	*9.0%*	*9.0%*	Return on Com Equity E	*10.0%*
	--	--	--	.6%	2.4%	1.8%	4.1%	3.1%	2.5%	*3.0%*	*3.0%*	*3.0%*	Retained to Com Eq	*3.5%*
	--	--	--	89%	69%	75%	57%	73%	69%	*68%*	*68%*	*68%*	All Div'ds to Net Prof	*63%*

BUSINESS: Evergy, Inc. was formed through the merger of Great Plains Energy and Westar Energy in June of 2018. Through its subsidiaries (now doing business under the Evergy name), provides electric service to 1.6 million customers in Kansas and Missouri, including the greater Kansas City area. Electric revenue breakdown: residential, 32%; commercial, 27%; industrial, 15%; wholesale, 13%; other, 13%. Generating sources: coal, 54%; nuclear, 17%; purchased, 29%. Fuel costs: 28% of revenues. '24 reported deprec. rate: 3%. Has 4,900 employees. Chairman: Mark A. Ruelle. President & CEO: David A. Campbell. COO: Kevin E. Bryant. Inc.: Missouri. Address: 1200 Main Street, Kansas City, Missouri 64105. Tel.: 816-556-2200. Internet: www.evergy.com.

Evergy appears set for solid earnings growth in 2025. The company reported first-quarter profits of $0.54 a share, nearly matching results from a year ago but falling short of our $0.65 estimate. Regulatory recovery on infrastructure investment supported results, though industrial activity was negatively impacted by unplanned maintenance and severe winter storms. Management reaffirmed its full-year earnings-per-share target of $3.92-$4.12, and we remain confident in our 2025 forecast, which is staying put. The Kansas rate case, which seeks a $196 million increase, is progressing and could take effect by September.

We continue to see multiple catalysts for mid- and long-term growth. Evergy is investing in two new 705 MW combined-cycle gas plants in Kansas, scheduled for completion in 2029 and 2030. The utility also expects strong customer growth, particularly from advanced manufacturing and data centers. Load growth is forecasted at 2%-3%, with potential upside depending on finalized contracts. Legislative progress in both Kansas and Missouri is providing a tailwind for capital investments and grid modernization. Notably, new policies are supporting wildfire mitigation efforts and data center readiness, giving Evergy a stronger competitive position in the central U.S. energy landscape. Our 2026 projection is staying put at $4.25 per share, implying a 5% year-over-year gain, within Evergy's long-term 4%-6% bottom-line growth target.

The dividend yield looks to be the stock's most compelling feature. The company recently declared a quarterly payout of $0.6675 per share, continuing its trend of consistent returns to shareholders. The current yield of 4.1% stands above the utility sector average.

Conservative, income-oriented accounts will likely want to take a closer look here. The stock is ranked 2 (Above Average) for Safety, and holds high scores for Price Stability (95) and Earnings Predictability (85). The utility has a proven track record of dividend increases and we look for more of the same in the future. Meanwhile, Evergy has been downgraded one notch in Timeliness to Below Average (4).

Zachary J. Hodgkinson *June 6, 2025*

(A) Diluted earnings. Next earnings report due early Aug. **(B)** Dividends paid in mid-March, June, September, and December. ■ Dividend reinvestment plan available. **(C)** Incl. intangibles. **(D)** In millions. **(E)** Rate base: Original cost depreciated. Rate allowed on common equity in Missouri in '18: none specified; in Kansas in '18: 9.3%; earned on average common equity, '22: 9.8%. Regulatory Climate: Average.

Company's Financial Strength	B++
Stock's Price Stability	95
Price Growth Persistence	20
Earnings Predictability	85

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FIRSTENERGY NYSE-FE

RECENT PRICE 42.72 | P/E RATIO 16.8 (Trailing: 15.5 Median: 14.0) | RELATIVE P/E RATIO 1.01 | DIV'D YLD 4.2% | VALUE LINE

TIMELINESS 4 Lowered 4/4/25
SAFETY 3 Lowered 7/31/20
TECHNICAL 4 Lowered 5/9/25
BETA .75 (1.00 = Market)

18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$35-$49	$42 (0%)

2028-30 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	65	(+50%)	*14%*
Low	45	(+5%)	*6%*

Institutional Decisions

	2Q2024	3Q2024	4Q2024
to Buy	357	403	423
to Sell	275	280	326
Hld's(000)	483657	528591	538043

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
High:	40.8	41.7	36.6	35.2	39.9	49.1	52.5	41.8	48.8	43.3	45.0	43.6						
Low:	30.0	28.9	29.3	27.9	29.3	36.3	22.9	29.2	35.3	32.2	35.4	37.6						

LEGENDS
25.6 x Dividends p sh
Relative Price Strength
Options: Yes
Shaded area indicates recession

Target Price Range 2028 | 2029 | 2030
128 96 80 64 48 40 32 24 16 12

% TOT. RETURN 4/28/25

	THIS STOCK	VL ARITH.* INDEX
1 yr.	16.8	2.2
3 yr.	8.1	12.5
5 yr.	23.9	137.1

Percent shares traded 30 20 10

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	© VALUE LINE PUB. LLC	28-30
	41.70	43.76	38.87	36.57	35.60	35.74	35.48	32.92	31.49	22.00	20.41	19.87	19.52	21.78	22.41	23.36	*25.25*	*25.80*	Revenues per sh	*28.55*
	8.80	8.50	5.75	6.05	6.30	6.26	7.04	7.04	6.54	5.19	4.80	4.59	5.41	4.71	4.78	5.38	*5.30*	*5.60*	"Cash Flow" per sh	*6.60*
	3.32	3.25	1.88	2.13	2.97	2.56	2.71	2.63	2.73	2.59	2.56	2.39	2.60	2.41	2.56	2.63	*2.55*	*2.70*	Earnings per sh [A]	*3.30*
	2.20	2.20	2.20	2.20	1.65	1.44	1.44	1.44	1.44	1.82	1.53	1.56	1.56	1.56	1.60	1.70	*1.78*	*1.86*	Div'd Decl'd per sh [B] ■	*2.10*
	7.23	6.44	5.45	7.09	6.90	8.42	6.83	6.93	6.38	5.23	4.93	4.89	4.29	4.82	5.84	6.99	*8.25*	*8.25*	Cap'l Spending per sh	*9.25*
	28.08	28.03	31.75	31.29	30.32	29.49	29.33	14.11	8.81	13.17	12.90	13.33	15.21	17.77	18.17	21.60	*22.25*	*23.25*	Book Value per sh [C]	*26.75*
	304.84	304.84	418.22	418.22	418.63	421.10	423.56	442.34	445.33	511.92	540.65	543.12	570.26	572.13	574.34	576.61	*580.00*	*585.00*	Common Shs Outst'g [D]	*595.00*
	13.0	11.7	22.4	21.1	13.1	13.2	12.6	12.7	11.4	13.6	17.1	15.7	14.1	17.0	14.9	15.2	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	*16.5*
	.87	.74	1.41	1.34	.74	.69	.63	.63	.67	.57	.73	.91	.81	.76	.98	.83	.80		Relative P/E Ratio	*.90*
	5.1%	5.8%	5.2%	4.9%	4.3%	4.3%	4.2%	4.3%	4.6%	5.2%	3.5%	4.2%	4.3%	3.8%	4.2%	4.2%			Avg Ann'l Div'd Yield	*3.9%*
							15029	14562	14022	11261	11035	10790	11132	12459	12870	13472	*14650*	*15100*	Revenues ($mill)	*17000*
							1144.0	1118.0	1213.0	1346.0	1380.0	1296.0	1419.0	1377.0	1468.0	1514.0	*1480*	*1585*	Net Profit ($mill)	*1970*
							35.8%	37.4%	37.2%	28.5%	19.8%	13.6%	20.6%	48.1%	16.2%	25.1%	*21.0%*	*21.0%*	Income Tax Rate	*21.0%*
							10.2%	9.2%	6.5%	4.8%	5.1%	5.9%	5.3%	6.1%	6.6%	8.8%	*9.0%*	*9.0%*	AFUDC % to Net Profit	*10.0%*
							60.7%	74.5%	84.3%	72.3%	73.8%	75.4%	71.9%	67.6%	68.7%	64.4%	*66.0%*	*65.5%*	Long-Term Debt Ratio	*65.0%*
							39.3%	25.5%	15.7%	27.4%	26.2%	24.6%	28.1%	32.4%	31.3%	35.6%	*34.0%*	*33.5%*	Common Equity Ratio	*35.0%*
							31613	24433	25040	24565	26593	29368	30923	31369	33322	34951	*37900*	*40900*	Total Capital ($mill)	*45300*
							37214	29387	28879	29911	31650	33294	34744	36285	38412	41102	*44400*	*47500*	Net Plant ($mill)	*57200*
							5.3%	6.6%	7.0%	7.4%	6.8%	6.0%	6.2%	5.9%	5.8%	5.7%	*5.5%*	*5.5%*	Return on Total Cap'l	*6.0%*
							9.2%	17.9%	30.9%	19.8%	19.8%	17.9%	16.4%	13.5%	14.1%	12.2%	*11.5%*	*11.5%*	Return on Shr. Equity [E]	*12.5%*
							9.2%	17.9%	30.9%	18.9%	19.7%	17.9%	16.4%	13.5%	14.1%	12.2%	*11.5%*	*11.5%*	Return on Com Equity [E]	*12.5%*
							4.3%	8.1%	14.6%	8.4%	8.1%	6.2%	6.6%	4.8%	5.4%	4.4%	*3.5%*	*3.5%*	Retained to Com Eq	*4.5%*
							53%	55%	53%	58%	59%	65%	60%	65%	62%	64%	*69%*	*68%*	All Div'ds to Net Prof	*63%*

CAPITAL STRUCTURE as of 12/31/24
Total Debt $24023 mill. **Due in 5 Yrs** $9373 mill.
LT Debt $22496 mill. **LT Interest** $975 mill.
Incl. $11 mill. finance leases.
(Total Interest coverage: 2.9x)
Leases, Uncapitalized Annual rentals $61 mill.

Pension Assets-12/24 $6296 mill.
Oblig. $7824 mill.
Pfd Stock None

Common Stock 576,697,425 shs.
as of 1/31/25
MARKET CAP: $24.6 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2022	2023	2024
% Change Retail Sales (MWH)	+1.5	-3.3	+2.8
Residential Use (MWH)	55994	52217	54631
Commercial Use (MWH)	39479	38179	39021
Industrial Use (MWH)	52008	52252	52950
Tot. Electric Deliv'd (MWH)	147481	142648	146602
Peak Load Summer (Mw)	NA	NA	NA
% Change Customers (yr-end)	+.4	+.5	+.5
Fixed Charge Cov. (%)	290	225	261

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '22-'24 to '28-'30
Revenues	-4.5%	-2.0%	*4.0%*
"Cash Flow"	-2.0%	-2.0%	*5.0%*
Earnings	- -	-.5%	*4.5%*
Dividends	-1.0%	.5%	*4.5%*
Book Value	-4.5%	10.5%	*5.5%*

Calendar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2022	2989	2818	3475	3177	12459
2023	3231	3006	3487	3146	12870
2024	3287	3280	3729	3176	13472
2025	3765	*3500*	*4000*	*3385*	*14650*
2026	*3900*	*3600*	*4125*	*3475*	*15100*

Calendar	EARNINGS PER SHARE [A] Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2022	.60	.53	.79	.50	2.41
2023	.60	.47	.88	.62	2.56
2024	.55	.56	.85	.67	2.63
2025	.67	*.53*	*.83*	*.52*	*2.55*
2026	*.64*	*.58*	*.90*	*.58*	*2.70*

Calendar	QUARTERLY DIVIDENDS PAID [B] ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	.39	.39	.39	.39	1.56
2022	.39	.39	.39	.39	1.56
2023	.39	.39	.39	.41	1.58
2024	.41	.425	.425	.425	1.69
2025	.425	.445			

BUSINESS: FirstEnergy Corp. is a holding company for Ohio Edison, Pennsylvania Power, Cleveland Electric, Toledo Edison, Metropolitan Edison, Penelec, Jersey Central Power & Light, West Penn Power, Potomac Edison, & Mon Power. Provides electric service to about 6.3 million customers in OH, PA, NJ, WV, MD, & NY. Acq'd Allegheny Energy 2/11. Electric revenue breakdown: residential, 60%; commercial, industrial & other, 40%. Purchases most of its power. Power costs: 32.5% of revenues. 2024 reported depreciation rate: 2.9%. Employs about 12,300. Chair, President and Chief Executive Officer: Brian X. Tierney. Incorporated: Ohio. Address: 76 South Main Street, Akron, Ohio 44308-1890. Telephone: 800-736-3402. Internet: www.firstenergycorp.com.

FirstEnergy changed how it reports adjusted (non-GAAP) earnings per share. According to leadership, the company has made substantial strides in improving its core regulated earnings over the past few years, but the growth has not come through clearly because of the impact of non-core components of historical operating profits. To rectify the situation, FirstEnergy will report adjusted earnings for its distribution, integrated, standalone transmission, and corporate segments, excluding the impact on profits from the pension and the company's interest in the non-core Signal Peak coal mine. We're not restating prior-year figures, but under the new format, last year's adjusted earnings would have been reported as $2.37 per share, a 7.7% gain from the comparable $2.20 pro forma level in 2023. Leadership's target for adjusted earnings this year is $2.40-$2.60 per share, but given the strong first-quarter results our call stands at $2.55. Next year, we're projecting core operating earnings of $2.70 per share, as the company continues to benefit from constructive rate settlements across much of its Mid-Atlantic service area.

The company's Ohio rate case has dragged on and has been met with a fair amount of political opposition. A year ago, FirstEnergy filed for higher rates in the state for the first time since the 2020 bribery scandal there came to light. While new leadership has done a good job of turning the page on that chapter of the company's history, the public is loath to forget it, and requests for higher prices make for good headlines in the local press. FirstEnergy requested a $190 million hike in annual revenue, which was met with a recommendation for an $8.5 million increase from the Public Utilities Commission of Ohio staff. The Ohio Consumer's Counsel, the state's consumer watchdog agency, has been actively involved in the case, suggesting significant price cuts. The company has since amended its request to $183 million. A final decision is expected by year's end. Ohio represents about 17% of FirstEnergy's rate base.

This issue is untimely. The 4.2% dividend yield compares favorably to the 3.6% industry median. But 3- to 5-year total return potential does not stand out.

Anthony J. Glennon *May 9, 2025*

(A) Diluted egs. excl. nonrc. losses: '13, $2.07; '14, $2.05; '15, $1.34; '16, $17.12; '17, $6.61; '18, $1.26; '19, 89¢; '20, 54¢; '21, 33¢; '22, $1.70; '23, 60¢; '24, 93¢; gain/(loss) from disc. ops.: '18, 66¢; '20, 14¢; '21, 8¢; '23, (4¢). Qtly. EPS don't sum due to rnd'g. Next egs. rpt. due late July. **(B)** Div. pd. Mar., June, Sept., & Dec. ■ Div'd reinv. avail. **(C)** Incl. intang. in '24: $10.81/sh. **(D)** In mill. **(E)** High ROE from large writeoffs. Rate base: Depr. orig. cost. Rates all'd on com. eq.: 9.5-11.3%; Reg.: OH Above Avg.; PA/NJ Avg.; MD/WV Below Avg.

Company's Financial Strength	B++
Stock's Price Stability	80
Price Growth Persistence	30
Earnings Predictability	100

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IDACORP, INC. NYSE-IDA

RECENT PRICE 116.35 | P/E RATIO 20.1 (Trailing: 20.7 Median: 20.0) | RELATIVE P/E RATIO 1.08 | DIV'D YLD 3.0% | VALUE LINE

TIMELINESS 4 Lowered 4/25/25
SAFETY 1 Raised 4/19/24
TECHNICAL 2 Lowered 7/18/25
BETA .70 (1.00 = Market)

18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$91-$130	$111 (-5%)

2028-30 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	150	(+30%)	*10%*
Low	120	(+5%)	*4%*

Institutional Decisions

	3Q2024	4Q2024	1Q2025
to Buy	226	235	230
to Sell	166	180	198
Hld's(000)	51027	52388	48315

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
High:	70.1	70.5	83.4	100.0	102.4	114.0	113.6	113.8	118.9	113.0	120.4	120.8						
Low:	50.2	55.4	65.0	77.5	79.6	89.3	69.1	85.3	93.5	88.1	86.4	104.7						

LEGENDS
30.50 x Dividends p sh divided by Interest Rate
Relative Price Strength
Options: Yes
Shaded area indicates recession

Target Price Range 2028 2029 2030

% TOT. RETURN 7/7/25

	THIS STOCK	VL ARITH.* INDEX
1 yr.	30.1	14.6
3 yr.	20.9	44.6
5 yr.	53.1	96.9

Percent shares traded

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	© VALUE LINE PUB. LLC	28-30
	21.92	20.97	20.55	21.55	24.81	25.51	25.23	25.04	26.76	27.19	26.70	26.77	28.86	32.51	34.90	33.85	*34.85*	*37.25*	Revenues per sh	*39.90*
	5.07	5.35	5.84	5.93	6.29	6.58	6.70	6.86	7.50	7.85	8.07	8.19	8.41	8.55	9.11	9.59	*10.20*	*11.25*	"Cash Flow" per sh	*12.75*
	2.64	2.95	3.36	3.37	3.64	3.85	3.87	3.94	4.21	4.49	4.61	4.69	4.85	5.11	5.14	5.50	*5.80*	*6.30*	Earnings per sh [A]	*7.10*
	1.20	1.20	1.20	1.37	1.57	1.76	1.92	2.08	2.24	2.40	2.56	2.72	2.88	3.04	3.20	3.35	*3.52*	*3.65*	Div'd Decl'd per sh [B] ■ †	*4.20*
	5.26	6.85	6.76	4.78	4.68	5.45	5.84	5.89	5.66	5.51	5.53	6.16	5.94	8.56	12.07	18.70	*20.00*	*22.50*	Cap'l Spending per sh	*25.00*
	29.17	31.01	33.19	35.07	36.84	38.85	40.88	42.74	44.65	47.01	48.88	50.73	52.82	55.52	57.44	61.73	*64.35*	*68.25*	Book Value per sh [C]	*72.25*
	47.90	49.41	49.95	50.16	50.23	50.27	50.34	50.40	50.42	50.42	50.42	50.46	50.52	50.56	50.62	53.96	*54.50*	*55.00*	Common Shs Outst'g [D]	*56.00*
	10.2	11.8	11.5	12.4	13.4	14.7	16.2	19.1	20.6	20.5	22.3	19.9	20.8	21.0	19.9	18.0	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	*19.0*
	.68	.75	.72	.79	.75	.77	.82	1.00	1.04	1.11	1.19	1.02	1.12	1.21	1.11	.95			Relative P/E Ratio	*1.05*
	4.5%	3.4%	3.1%	3.3%	3.2%	3.1%	3.1%	2.8%	2.6%	2.6%	2.5%	2.9%	2.9%	2.8%	3.1%	3.4%			Avg Ann'l Div'd Yield	*3.1%*
							1270.3	1262.0	1349.5	1370.8	1346.4	1350.7	1458.1	1644.0	1766.4	1826.6	*1900*	*2050*	Revenues ($mill)	*2235*
							194.7	198.3	212.4	226.8	232.9	237.4	245.6	259.0	261.2	289.2	*315*	*345*	Net Profit ($mill)	*400*
							19.0%	15.5%	18.6%	7.1%	9.5%	10.8%	13.1%	12.7%	9.4%	4.9%	*13.0%*	*13.0%*	Income Tax Rate	*13.0%*
							16.3%	16.3%	13.9%	15.2%	16.2%	17.3%	17.7%	19.8%	8.8%	8.8%	*9.0%*	*9.0%*	AFUDC % to Net Profit	*12.0%*
							45.6%	44.8%	43.7%	43.6%	41.3%	43.9%	42.8%	43.9%	48.8%	47.8%	*49.0%*	*47.5%*	Long-Term Debt Ratio	*45.0%*
							54.4%	55.2%	56.3%	56.4%	58.7%	56.1%	57.2%	56.1%	51.2%	52.2%	*51.0%*	*52.5%*	Common Equity Ratio	*55.0%*
							3783.3	3898.5	3997.5	4205.1	4201.3	4560.4	4669.1	5001.4	5683.4	6384.7	*6950*	*7150*	Total Capital ($mill)	*7400*
							3992.4	4172.0	4283.9	4395.7	4531.5	4709.5	4901.8	5173.0	5745.2	6517.3	*7285*	*8000*	Net Plant ($mill)	*9450*
							6.2%	6.1%	6.3%	6.4%	6.5%	6.1%	6.2%	6.1%	5.4%	5.6%	*4.5%*	*5.0%*	Return on Total Cap'l	*5.5%*
							9.5%	9.2%	9.4%	9.6%	9.4%	9.3%	9.2%	9.2%	9.0%	8.7%	*9.0%*	*9.0%*	Return on Shr. Equity	*10.0%*
							9.5%	9.2%	9.4%	9.6%	9.4%	9.3%	9.2%	9.2%	9.0%	8.7%	*9.0%*	*9.0%*	Return on Com Equity [E]	*10.0%*
							4.8%	4.3%	4.4%	4.4%	4.2%	3.9%	3.7%	3.7%	3.4%	3.4%	*3.5%*	*4.0%*	Retained to Com Eq	*4.0%*
							50%	53%	53%	54%	56%	58%	60%	60%	63%	61%	*60%*	*58%*	All Div'ds to Net Prof	*59%*

CAPITAL STRUCTURE as of 3/31/25
Total Debt $3447.0 mill. **Due in 5 Yrs** $136.2 mill.
LT Debt $3447.0 mill. **LT Interest** $150.0 mill.
(Total Interest Coverage: 2.5x)

Pension Assets-12/24 $951.1 mill.
Oblig $998.0 mill.

Pfd Stock None

Common Stock 54,020,202 shs.
as of 4/25/25

MARKET CAP: $6.3 billion (Mid Cap)

ELECTRIC OPERATING STATISTICS

	2022	2023	2024
% Change Retail Sales (KWH)	+9.6	+7.3	+2.9
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	3568	3615	3793
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+2.4	+2.4	+2.2
Fixed Charge Cov. (%)	395	315	328

ANNUAL RATES of change (per sh)

	Past 10 Yrs.	Past 5 Yrs.	Est'd '22-'24 to '28-'30
Revenues	3.5%	4.5%	*3.5%*
"Cash Flow"	4.0%	3.0%	*6.0%*
Earnings	4.0%	3.5%	*6.0%*
Dividends	7.5%	6.0%	*5.5%*
Book Value	4.5%	4.5%	*4.5%*

QUARTERLY REVENUES($ mill.)

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2022	344.3	358.7	518.0	422.9	1644.0
2023	429.7	413.8	510.9	412.0	1766.4
2024	448.9	451.1	528.5	398.1	1826.6
2025	432.5	*480*	*550*	*437.5*	*1900*
2026	*500*	*520*	*550*	*480*	*2050*

EARNINGS PER SHARE [A]

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2022	.91	1.27	2.10	.83	5.11
2023	1.11	1.35	2.07	.61	5.14
2024	.95	1.71	2.12	.70	5.50
2025	1.10	*1.80*	*2.20*	*.70*	*5.80*
2026	*1.10*	*1.85*	*2.50*	*.85*	*6.30*

QUARTERLY DIVIDENDS PAID [B] ■ †

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	.71	.71	.71	.75	2.88
2022	.75	.75	.75	.79	3.04
2023	.79	.79	.79	.83	3.20
2024	.83	.83	.83	.86	3.35
2025	.86	.86			

BUSINESS: IDACORP, Inc. is a holding company for Idaho Power Company, a regulated electric utility that serves 649,000 customers throughout a 24,000-square-mile area in southern Idaho and eastern Oregon (population: 1.4 million). Most of the company's revenues are derived from the Idaho portion of its service area. Revenue breakdown: residential, 38%; commercial, 22%; industrial, 15%; irrigation, 11%; other, 14%. Generating sources: hydro, 54%; steam fired, 18%; gas, 28%; purchased,33%. Fuel costs: 14% of revenues. '24 depreciation rate: 12.2%. Has 2,141 employees. Chairman: Dennis L. Johnson. President & CEO: Lisa A. Grow. Incorporated: Idaho. Address: 1221 W. Idaho St., Boise, Idaho 83702. Telephone: 208-388-2200. Internet: www.idacorpinc.com.

IDACORP continues to enjoy healthy share earnings despite elevated infrastructure costs. First-quarter results benefited from strong customer growth, recent rate cases, and the expected application of federal tax credits through Idaho's regulatory framework. These tailwinds helped offset rising depreciation and financing costs tied to its expanding infrastructure base.

We anticipate earnings momentum to carry through the rest of the year. Management reaffirmed its full-year guidance of $5.65-$5.85 per share based on assumptions of typical weather and stable power supply costs. The utility also expects to use $60 million to $77 million in additional tax credits through 2025, helping ease the cost of service for customers. Rate increases implemented at the start of the year should also lend support. In all, we estimate 2025 earnings to land near the high end of guidance, around $5.80, with a further increase to $6.30 in 2026, reflecting annual growth of more than 5% and 8%, respectively.

IDACORP has mapped out a substantial capital investment strategy. The utility plans to invest $1.0 billion to $1.1 billion in 2025, between $1.25 billion and $1.35 billion in 2026, and $3.1 billion to $3.6 billion from 2027 to 2029. These funds will support a broad range of projects, including three major transmission lines, resource procurement for new generation, and continued enhancements to system reliability. The company's 2025 Integrated Resource Plan, recently filed with regulators, highlights the urgent need for additional energy resources, battery storage, and efficiency programs as it prepares for one of its most rapid demand expansions. Over the next 20 years, peak demand is expected to rise nearly 45%, or roughly 1,700 megawatts, with more than half of that increase arriving in the next five years.

That said, IDACORP's investment appeal may remain limited in the near term. At the current quotation, the equity is ranked to underperform the broader market averages. At 3.0%, the dividend yield is below average for the utility sector, and capital appreciation potential appears subpar.

Emma Jalees *July 18, 2025*

(A) Diluted EPS. Earnings may not sum due to rounding. Next earnings report due July 31st. **(B)** Dividends historically paid in late February, May, August, and November. ■ Dividend reinvestment plan available. † Shareholder investment plan available. **(C)** Incl. intangibles. In '24: $1418.0 mill., $26.28/sh. **(D)** In millions. **(E)** Rate base: Net original cost. Rate allowed on common equity in '12: 10% (imputed); Regulatory Climate: Above Average.

Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	50
Earnings Predictability	100

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OGE ENERGY CORP. NYSE-OGE

RECENT PRICE 44.24 | P/E RATIO 19.2 (Trailing: 18.4 Median: 18.0) | RELATIVE P/E RATIO 1.10 | DIV'D YLD 3.9% | VALUE LINE

TIMELINESS 4 Lowered 5/23/25
SAFETY 2 Raised 6/6/25
TECHNICAL 1 Raised 5/23/25
BETA .85 (1.00 = Market)

18-Month Target Price Range

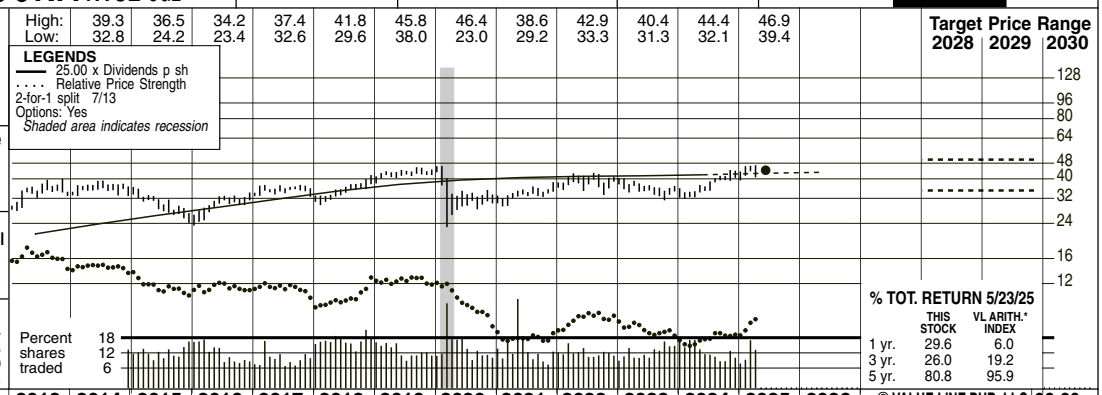
Low-High	Midpoint (% to Mid)
$33-$52	$43 (-5%)

2028-30 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	50	(+15%)	7%
Low	35	(-20%)	-1%

Institutional Decisions

	2Q2024	3Q2024	4Q2024
to Buy	217	230	246
to Sell	211	205	229
Hld's(000)	142329	165132	172216



Target Price Range 2028 | 2029 | 2030: 128, 96, 80, 64, 48, 40, 32, 24, 16, 12

% TOT. RETURN 5/23/25

	THIS STOCK	VL ARITH.* INDEX
1 yr.	29.6	6.0
3 yr.	26.0	19.2
5 yr.	80.8	95.9

2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	© VALUE LINE PUB. LLC	28-30
14.79	19.04	19.96	18.58	14.45	12.30	11.00	11.31	11.32	11.37	11.15	10.61	18.26	16.86	13.36	14.86	*15.75*	*16.25*	Revenues per sh	*18.75*
2.69	3.01	3.31	3.69	3.46	3.40	3.23	3.31	3.34	3.74	4.02	4.03	4.44	5.63	4.61	4.70	*5.05*	*5.25*	"Cash Flow" per sh	*6.10*
1.33	1.50	1.73	1.79	1.94	1.98	1.69	1.69	1.92	2.12	2.24	2.08	2.36	2.25	2.07	2.19	*2.30*	*2.45*	Earnings per sh [A]	*2.95*
.71	.73	.76	.80	.85	.95	1.05	1.16	1.27	1.40	1.51	1.58	1.63	1.64	1.66	1.68	*1.71*	*1.73*	Div'd Decl'd per sh [B] ■	*1.79*
4.37	4.36	6.48	5.85	4.99	2.86	2.74	3.31	4.13	2.87	3.18	3.25	3.89	5.25	4.49	4.62	*4.75*	*4.75*	Cap'l Spending per sh	*4.75*
10.52	11.73	13.06	14.00	15.30	16.27	16.66	17.24	19.28	20.06	20.69	18.15	20.27	22.52	22.17	22.87	*23.75*	*24.25*	Book Value per sh [C]	*26.25*
194.00	195.20	196.20	197.60	198.50	199.40	199.70	199.70	199.70	199.70	200.10	200.10	200.10	200.20	200.30	200.9	*200.20*	*200.20*	Common Shs Outst'g [D]	*200.20*
10.8	13.3	14.4	15.2	17.7	18.3	17.7	17.7	18.3	16.5	19.0	16.2	14.3	17.2	17.4	17.0	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	*14.0*
.72	.85	.90	.97	.99	.96	.89	.93	.92	.89	1.01	.83	.77	1.00	.96	.95			Relative P/E Ratio	*.80*
5.0%	3.7%	3.1%	2.9%	2.5%	2.6%	3.5%	3.9%	3.6%	4.0%	3.5%	4.7%	4.8%	4.5%	5.1%	3.9%			Avg Ann'l Div'd Yield	*4.2%*
2196.9	2259.2	2261.1	2270.3	2231.6	2122.3	3653.7	3375.7	2674.3	2985.3	*3150*	*3250*	Revenues ($mill)	*3750*
337.6	338.2	384.3	425.5	449.6	415.9	472.5	665.7	416.8	438.4	*460*	*480*	Net Profit ($mill)	*590*
29.2%	30.5%	32.5%	14.5%	7.4%	13.2%	11.5%	12.0%	12.0%	12.1%	*12.0%*	*12.0%*	Income Tax Rate	*12.0%*
3.7%	6.4%	15.0%	8.3%	1.6%	1.6%	2.2%	2.0%	1.8%	2.0%	*2.0%*	*2.0%*	AFUDC % to Net Profit	*2.0%*
44.3%	41.1%	41.7%	42.0%	43.6%	49.0%	52.6%	49.8%	51.2%	51.4%	*51.5%*	*51.0%*	Long-Term Debt Ratio	*50.0%*
55.7%	58.9%	58.3%	58.0%	56.4%	51.0%	47.4%	52.4%	49.6%	49.2%	*48.5%*	*49.0%*	Common Equity Ratio	*50.0%*
5971.6	5849.6	6600.7	6902.0	7334.7	7126.2	8552.7	8962.0	9238.2	9726.8	*9935*	*10100*	Total Capital ($mill)	*10400*
7322.4	7696.2	8339.9	8643.8	9044.6	9374.6	9832.9	10546.8	11301.0	11538.0	*11650*	*11750*	Net Plant ($mill)	*12075*
6.9%	7.0%	7.0%	7.3%	7.1%	6.9%	6.4%	5.9%	6.3%	6.8%	*7.0%*	*7.0%*	Return on Total Cap'l	*7.5%*
10.2%	9.8%	10.0%	10.6%	10.9%	11.5%	11.6%	11.0%	12.0%	12.3%	*12.5%*	*12.5%*	Return on Shr. Equity	*13.0%*
10.2%	9.8%	10.0%	10.6%	10.9%	11.5%	11.6%	11.0%	12.0%	12.3%	*12.5%*	*12.5%*	Return on Com Equity [E]	*13.0%*
4.0%	3.3%	3.5%	3.8%	3.6%	2.8%	3.6%	3.0%	3.5%	3.8%	*4.5%*	*4.5%*	Retained to Com Eq	*5.5%*
61%	67%	64%	64%	67%	76%	69%	73%	81%	75%	*75%*	*75%*	All Div'ds to Net Prof	*70%*

CAPITAL STRUCTURE as of 3/31/25
Total Debt $5054.2 mill. **Due in 5 Yrs** $1731.5 mill.
LT Debt $5021.8 mill. **LT Interest** $158.7 mill.
(LT interest earned: 4.3x)

Leases, Uncapitalized Annual rentals $5.7 mill.

Pension Assets-12/24 $486.0 mill.
Oblig $502.9 mill.

Pfd Stock None

Common Stock 201,330,195 shs.

MARKET CAP: $8.9 billion (Mid Cap)

ELECTRIC OPERATING STATISTICS

	2022	2023	2024
% Change Retail Sales (KWH)	-4.9	+2.6	+8.3
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	4.40	7.68	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	6437	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+1.1	+1.4	NA
Fixed Charge Cov. (%)	326	336	335

ANNUAL RATES of change (per sh)

	Past 10 Yrs.	Past 5 Yrs.	Est'd '22-'24 to '28-'30
Revenues	-3.0%	5.0%	*5.5%*
"Cash Flow"	2.5%	5.0%	*7.0%*
Earnings	3.0%	4.5%	*6.5%*
Dividends	7.5%	6.5%	*3.0%*
Book Value	4.0%	1.5%	*5.5%*

QUARTERLY REVENUES ($ mill.)

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2022	589.3	803.7	1270.8	711.9	3375.7
2023	557.2	605.0	945.4	566.7	2674.3
2024	596.8	662.6	965.4	760.5	2985.3
2025	747.7	*750*	*1000*	*652.3*	*3150*
2026	*675*	*855*	*1010*	*710*	*3250*

EARNINGS PER SHARE [A]

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2022	.33	.36	1.31	.25	2.25
2023	.19	.44	1.20	.24	2.07
2024	.09	.51	1.09	.50	2.19
2025	.31	*.55*	*1.20*	*.24*	*2.30*
2026	*.30*	*.55*	*1.30*	*.30*	*2.45*

QUARTERLY DIVIDENDS PAID [B] ■

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	.4025	.4025	.4025	.41	1.62
2022	.41	.41	.41	.4141	1.64
2023	.4141	.4141	.4141	.4182	1.66
2024	.4182	.4182	.4182	.4213	1.68
2025	.4213	.4213			

BUSINESS: OGE Energy Corp. is a holding company for Oklahoma Gas and Electric Company (OG&E), which supplies electricity to 879,000 customers in Oklahoma (84% of electric revenues) and western Arkansas (8%); wholesale is (8%). Owns 3% of Energy Transfer's limited partnership units. Electric revenue breakdown: residential, 44%; commercial, 25%; industrial, 11%; oilfield, 10%; other, 10%. Generating sources: gas, 25%; coal, 21%; wind, 6%; purchased, 48%. Fuel costs: 58% of revenues. '24 reported depreciation rate (utility): 2.6%. Has 2,200 employees. Chairman, President and Chief Executive Officer: Sean Trauschke. Incorporated: Oklahoma. Address: 321 North Harvey, P.O. Box 321, Oklahoma City, OK 73101-0321. Tel.: 405-553-3000. Internet: www.oge.com.

OGE Energy is positioned for another year of solid earnings growth. The utility posted first-quarter earnings of $0.31 per share, ahead of our $0.25 estimate and up sharply from $0.09 a year ago. OG&E, the utility subsidiary, contributed nicely, driven by strong demand and lower operating expenses, partially offset by holding company losses. Overall, residential and commercial loads rose 3% and 28% respectively, leading to 8% weather-normalized load growth. A 1% increase in customer count, paired with ongoing grid modernization, also supported results. The company reaffirmed its full year earnings target range of $2.21-$2.33, and our 2025 estimate remains unchanged at $2.30 per share.

We are monitoring potential regulatory hurdles in Oklahoma. While the Oklahoma Corporation Commission approved a $127 million rate increase last year, a new legal challenge could affect the implementation. State lawmakers have petitioned the Oklahoma Supreme Court to disqualify Commissioner Todd Hiett, who cast the deciding vote. The case, if successful, could delay or unwind the rate decision. Meanwhile, OGE is pursuing additional regulatory filings in both Oklahoma and Arkansas tied to resource planning and customer growth.

The long-term outlook for the utility remains bright. Management reaffirmed its long-term earnings growth goal of 5%-7%, and we are maintaining our 2026 forecast of $2.45 per share, which reflects 7% year-over-year growth. Load expansion tied to data center clients, including Google, could provide further upside as agreements finalize and generation needs are submitted to regulators. Proactive supply chain planning, including advance transformer orders through 2027, helps mitigate inflationary and logistics risks. OGE's competitive rates in Oklahoma and Arkansas position it favorably in a rising demand environment.

Income-oriented investors may want to take a closer look. Indeed, the dividend yield of 3.9% continues to stand above the high industry-wide average. Meanwhile, the utility was recently downgraded one notch to Below Average (4) for Timeliness.

Zachary J. Hodgkinson *June 6, 2025*

(A) Diluted EPS. Excl. nonrecurring gains (losses): '15, (33¢); '17, $1.18; '19, (8¢); '20, ($2.95); '21, $1.32; '22, $1.06; gain on discont. ops.: '19 & '21 EPS don't sum due to rounding. Next earnings report due early Aug. **(B)** Div'ds historically paid in late Jan., Apr., July, & Oct. ■ Div'd reinvestment plan avail. **(C)** Incl. deferred charges. In '22: $6.15/sh. **(D)** In mill., adj. for split. **(E)** Rate base: Net original cost. Rate allowed on com. eq. in OK in '19: 9.5%; in AR in '18: 9.5%; earned on avg. com. eq., '21: 12.7%. Regulatory Climate: Average.

Company's Financial Strength	B++
Stock's Price Stability	95
Price Growth Persistence	40
Earnings Predictability	95

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PINNACLE WEST NYSE-PNW

RECENT PRICE **90.10** | P/E RATIO **18.8** (Trailing: 17.9 Median: 17.0) | RELATIVE P/E RATIO **1.01** | DIV'D YLD **4.0%** | **VALUE LINE**

TIMELINESS 4 Lowered 6/6/25
SAFETY 2 Raised 10/18/24
TECHNICAL 1 Raised 7/11/25
BETA .75 (1.00 = Market)

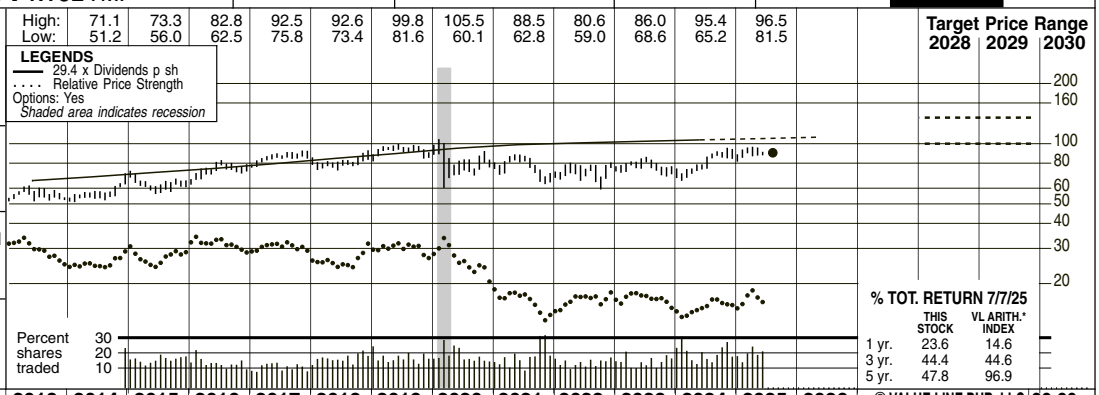
18-Month Target Price Range
Low-High **Midpoint (% to Mid)**
$72-$108 $90 (0%)

2028-30 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	135	(+50%)	*14%*
Low	100	(+10%)	*7%*

Institutional Decisions

	3Q2024	4Q2024	1Q2025
to Buy	274	320	306
to Sell	226	241	254
Hld's(000)	123296	122886	113313



2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	© VALUE LINE PUB. LLC	28-30
32.50	30.01	29.67	30.09	31.35	31.58	31.50	31.42	31.90	32.93	30.87	31.81	33.66	38.21	41.40	43.03	*44.40*	*46.30*	Revenues per sh	*53.20*
8.08	6.85	7.52	7.92	8.15	8.09	9.09	9.39	9.92	10.37	10.69	10.97	11.84	11.50	11.95	13.14	*12.85*	*13.60*	"Cash Flow" per sh	*16.45*
2.26	3.08	2.99	3.50	3.66	3.58	3.92	3.95	4.43	4.54	4.77	4.87	5.47	4.26	4.41	5.24	*4.80*	*5.15*	Earnings per sh [A]	*6.45*
2.10	2.10	2.10	2.67	2.23	2.33	2.44	2.56	2.70	2.87	3.04	3.23	3.36	3.43	3.49	3.55	*3.61*	*3.67*	Div'd Decl'd per sh [B] ■	*4.00*
7.64	7.03	8.26	8.24	9.36	8.38	9.84	11.64	12.80	10.73	10.76	11.93	13.04	15.09	16.28	18.89	*16.75*	*17.00*	Cap'l Spending per sh	*17.50*
32.69	33.86	34.98	36.20	38.07	39.50	41.30	43.15	44.80	46.59	48.30	49.96	52.26	53.45	54.47	56.71	*58.00*	*58.75*	Book Value per sh [C]	*70.20*
101.43	108.77	109.25	109.74	110.18	110.57	110.98	111.34	111.75	112.10	112.44	112.76	113.01	113.17	113.42	119.10	*120.50*	*122.00*	Common Shs Outst'g [D]	*125.00*
13.7	12.6	14.6	14.3	15.3	15.9	16.0	18.7	19.3	17.8	19.4	16.7	14.1	17.1	17.4	15.3	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	*18.00*
.91	.80	.92	.91	.86	.84	.81	.98	.97	.96	1.03	.86	.76	.99	.97	.81			Relative P/E Ratio	*1.00*
6.8%	5.4%	4.8%	5.3%	4.0%	4.1%	3.9%	3.5%	3.2%	3.5%	3.3%	4.0%	4.3%	4.7%	4.5%	4.4%			Avg Ann'l Div'd Yield	*3.4%*
3495.4	3498.7	3565.3	3691.2	3471.2	3587.0	3803.8	4324.4	4696.0	5124.9	*5350*	*5650*	Revenues ($mill)	*6650*
437.3	442.0	497.8	511.0	538.3	550.6	618.7	483.6	501.6	608.8	*575*	*625*	Net Profit ($mill)	*805*
34.3%	33.9%	32.5%	20.2%	- -	12.1%	14.8%	13.0%	12.9%	15.0%	*15.0%*	*15.0%*	Income Tax Rate	*15.0%*
11.8%	14.1%	13.9%	15.2%	9.3%	9.5%	10.1%	15.2%	19.3%	14.3%	*15.0%*	*15.0%*	AFUDC % to Net Profit	*15.0%*
43.0%	45.6%	48.9%	47.0%	47.1%	52.8%	53.9%	56.1%	55.0%	54.4%	*55.5%*	*57.0%*	Long-Term Debt Ratio	*55.0%*
57.0%	54.4%	51.1%	53.0%	52.9%	47.2%	46.1%	43.9%	45.0%	45.6%	*44.5%*	*43.0%*	Common Equity Ratio	*45.0%*
8046.3	8825.4	9796.4	9861.1	10263	11948	12820	13790	13718	14813	*15800*	*16725*	Total Capital ($mill)	*19525*
11809	12714	13445	14030	14523	15159	15987	16854	17980	19198	*20225*	*21250*	Net Plant ($mill)	*24150*
6.4%	6.0%	6.1%	6.2%	6.3%	5.5%	5.8%	4.5%	4.9%	5.5%	*5.0%*	*5.0%*	Return on Total Cap'l	*5.5%*
9.5%	9.2%	9.9%	9.8%	9.9%	9.8%	10.5%	8.0%	8.1%	9.0%	*8.0%*	*8.5%*	Return on Shr. Equity	*9.0%*
9.5%	9.2%	9.9%	9.8%	9.9%	9.8%	10.5%	8.0%	8.1%	9.0%	*8.0%*	*8.5%*	Return on Com Equity [E]	*9.0%*
3.9%	3.5%	4.2%	3.9%	3.8%	3.5%	4.2%	1.7%	1.9%	3.2%	*2.0%*	*2.5%*	Retained to Com Eq	*3.5%*
59%	62%	58%	60%	61%	64%	60%	78%	77%	65%	*75%*	*71%*	All Div'ds to Net Prof	*62%*

CAPITAL STRUCTURE as of 3/31/25
Total Debt $9730.9 mill. **Due in 5 Yrs** $2794.0 mill.
LT Debt $8060.7 mill. **LT Interest** $400.0 mill.
(Total Interest Coverage: 2.7x)

Leases, Uncapitalized Annual rentals $20.1 mill.

Pension Assets-12/24 $2639.9 mill.
Oblig. $2792.3 mill.

Pfd Stock None

Common Stock 119,399,009 shs.
as of 4/24/25
MARKET CAP: $10.7 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2022	2023	2024
% Change Retail Sales (KWH)	+4.4	+2.8	+7.4
Total Ret'l Revs. per KWH (¢)	12.50	13.83	14.53
Avg. Indust. Revs. per KWH (¢)	9.20	10.38	10.18
Capacity at Peak (Mw)	8612	9629	9466
Peak Load, Summer (Mw)	7587	8162	8210
Annual Load Factor (%)	48.1	45.7	47.5
% Change Customers (yr-end)	+2.1	+1.8	+2.1
Fixed Charge Cov. (%)	258	220	238

ANNUAL RATES of change (per sh)

	Past 10 Yrs.	Past 5 Yrs.	Est'd '22-'24 to '28-'30
Revenues	3.0%	5.0%	*4.5%*
"Cash Flow"	4.0%	3.5%	*5.0%*
Earnings	2.5%	- -	*5.0%*
Dividends	4.0%	4.0%	*1.5%*
Book Value	4.0%	3.5%	*4.0%*

QUARTERLY REVENUES ($ mill.)

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2022	783.5	1061.7	1469.9	1009.3	4324.4
2023	945.0	1121.7	1637.8	991.5	4696.0
2024	951.7	1309.0	1768.8	1095.4	5124.9
2025	1032.3	*1357.7*	*1810*	*1150*	*5350*
2026	*1090*	*1435*	*1900*	*1225*	*5650*

EARNINGS PER SHARE [A]

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2022	.15	1.45	2.88	d.21	4.26
2023	d.03	.94	3.50	Nil	4.41
2024	.15	1.76	3.37	d.06	5.24
2025	d.04	*1.65*	*3.20*	*d.01*	*4.80*
2026	*.11*	*1.70*	*3.35*	*d.01*	*5.15*

QUARTERLY DIVIDENDS PAID [B] ■

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	.83	.83	.83	.85	3.34
2022	.85	.85	.85	.865	3.42
2023	.865	.865	.865	.88	3.48
2024	.88	.88	.88	.895	3.54
2025	.895	.895			

BUSINESS: Pinnacle West Capital Corporation is a holding company for Arizona Public Service Company (APS), which supplies electricity to 1.4 million customers in most of Arizona, except about half of the Phoenix metro area, the Tucson metro area, and Mohave County in northwestern Arizona. Discontinued SunCor real estate subsidiary in '10. Electric revenue breakdown: residential, 50%; commercial/industrial, 46%; other, 4%. Generating sources: gas, 24%; nuclear, 21%; coal, 14%; renewables, 19%; purchased, 22%. Fuel costs: 36% of revenues. '24 reported deprec. rate: 3.13%. Has 6,403 employees. Chairman, President & CEO: Ted Geisler. Inc.: AZ. Address: 400 North Fifth St., P.O. Box 53999, Phoenix, AZ 85072-3999. Tel.: 602-250-1000. Internet: www.pinnaclewest.com.

Pinnacle West Capital's profits will likely be down in 2025. The utility benefited from a record heat wave last year in Arizona that lifted cooling demand, helping to send retail sales volume up 7.4%. Leadership affirmed its 2025 weather-normalized earnings projection of $4.40 to $4.60 per share. This range takes into account the first quarter loss, which was largely due to higher planned operations and maintenance expense related to power plant overhauls. The extra work was needed to ensure reliability during peak seasonal demand. Still, we think the company will prove to be a bit too conservative in its forecast. Sweltering heat in 2022 and 2023, followed by an even more oppressive stretch last year, doesn't seem like a trend that will readily pivot back to normalized temperatures. In addition, Pinnacle West's service area benefits from strong migration, as Arizona's 2.5% flat income tax rate helps draw in out-of-state retirees. A business friendly government also keeps the regional economy headed in the right direction. Customer growth rose 2.1% in 2024 and 2.3% during the March quarter. It will probably be up similar levels over the next couple of years.

Earnings should be back on a growth trajectory in 2026. In addition to the higher than typical electricity volumes in 2024, which make for difficult quarterly bottom-line comparisons this year, the company is also experiencing regulatory lag. The utility filed a rate case application in June, seeking a net base-rate increase of $580 million. It should garner a decision next year, and a potential revenue increase in the back half of 2026. In the utility's most recent rate-case decision, handed down in February 2024, it received fair treatment from a revamped Arizona Public Service Commission.

This issue is untimely. Longer term, we continue to like this electric utility, as it is the beneficiary of a premium service area with rising energy demand from population growth and a healthy economy. Still, utility investors need to be disciplined buyers and wait for a better entry point. We think a 5% drawdown, sending the stock into the mid-$80 area, would provide a worthwhile risk-adjusted annual total return expectation.

Anthony J. Glennon *July 18, 2025*

(A) Diluted EPS. Excl. nonrec. gain/(loss): '09, ($1.45); '17, 8¢; gains/(losses) from discont. ops.: '09, (13¢); '10, 18¢; '11, 10¢; '12, (5¢). Qtly. EPS may not sum to full year due to rounding. Next egs. report due early August. **(B)** Div'ds historically paid in early Mar., June, Sept., & Dec. There were 5 declarations in '12. ■ Div'd reinvestment plan avail. **(C)** Incl. deferred charges/other intangibles. In '24: $33.55/sh. **(D)** In mill. **(E)** Rate base: Fair value. Rate allowed on common equity in '24: 9.55%-9.85%. Regulatory Climate: Average.

Company's Financial Strength	B++
Stock's Price Stability	95
Price Growth Persistence	30
Earnings Predictability	80

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PORTLAND GENERAL NYSE-POR

RECENT PRICE **40.91** | P/E RATIO **12.6** (Trailing: 14.4 Median: 18.0) | RELATIVE P/E RATIO **0.68** | DIV'D YLD **5.2%** | **VALUE LINE**

TIMELINESS 3 Lowered 4/25/25
SAFETY 2 Raised 7/19/24
TECHNICAL 3 Raised 6/20/25
BETA .75 (1.00 = Market)

18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$38-$57	$48 (15%)

2028-30 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	70	(+70%)	*18%*
Low	50	(+20%)	*10%*

Institutional Decisions

	3Q2024	4Q2024	1Q2025
to Buy	241	241	255
to Sell	166	192	188
Hld's(000)	118198	121028	108458

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
High:	40.3	41.0	45.2	50.1	50.4	58.4	63.1	53.1	57.0	51.6	49.8	45.9						
Low:	29.0	33.0	35.3	42.4	39.0	44.0	32.0	40.8	41.6	38.0	39.1	39.5						

Target Price Range 2028 | 2029 | 2030

LEGENDS
23.3 x Dividends p sh
Relative Price Strength
Options: Yes
Shaded area indicates recession

Percent shares traded: 21, 14, 7

% TOT. RETURN 7/7/25

	THIS STOCK	VL ARITH.* INDEX
1 yr.	0.9	14.6
3 yr.	-4.5	44.6
5 yr.	21.8	96.9

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	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Revenues per sh	23.99	23.67	24.06	23.89	23.18	24.29	21.38	21.62	22.54	22.30	23.75	23.96	26.80	29.65	28.90	31.46	*32.45*	*32.90*
"Cash Flow" per sh	4.07	4.82	4.96	5.15	4.93	6.08	5.37	5.78	6.16	6.65	6.97	7.83	7.25	7.41	6.83	7.53	*8.15*	*8.40*
Earnings per sh A	1.31	1.66	1.95	1.87	1.77	2.18	2.04	2.16	2.29	2.37	2.39	2.75	2.72	2.74	2.38	3.14	*3.25*	*3.40*
Div'd Decl'd per sh B ■ †	1.01	1.04	1.06	1.08	1.10	1.12	1.18	1.26	1.34	1.43	1.52	1.59	1.70	1.79	1.88	1.98	*2.08*	*2.20*
Cap'l Spending per sh	9.25	5.97	3.98	4.01	8.40	12.87	6.73	6.57	5.77	6.67	6.78	8.76	7.11	8.58	13.42	11.60	*11.50*	*11.50*
Book Value per sh C	20.50	21.14	22.07	22.87	23.30	24.43	25.43	26.35	27.11	28.07	28.99	29.18	30.28	31.13	32.81	34.70	*36.00*	*37.50*
Common Shs Outst'g D	75.21	75.32	75.36	75.56	78.09	78.23	88.79	88.95	89.11	89.27	89.39	89.54	89.41	89.28	101.16	109.34	*111.00*	*114.00*
Avg Ann'l P/E Ratio	14.4	12.0	12.4	14.0	16.9	15.3	17.7	19.1	20.0	18.4	22.3	16.6	17.7	18.2	19.3	14.2	*Bold figures are Value Line estimates*	
Relative P/E Ratio	.96	.76	.78	.89	.95	.81	.89	1.00	1.01	.99	1.19	.85	.96	1.05	1.07	.75		
Avg Ann'l Div'd Yield	5.4%	5.2%	4.4%	4.1%	3.7%	3.3%	3.3%	3.1%	2.9%	3.3%	2.8%	3.5%	3.5%	3.6%	4.1%	4.4%		
Revenues ($mill)							1898.0	1923.0	2009.0	1991.0	2123.0	2145.0	2396.0	2647.0	2923.0	3440.0	*3600*	*3750*
Net Profit ($mill)							172.0	193.0	204.0	212.0	214.0	247.0	244.0	245.0	233.0	327.0	*355*	*385*
Income Tax Rate							20.7%	20.6%	25.3%	7.4%	11.2%	12.4%	8.6%	15.2%	16.8%	11.4%	*17.5%*	*17.5%*
AFUDC % to Net Profit							19.8%	16.6%	8.8%	8.0%	7.0%	9.7%	10.2%	8.6%	13.7%	11.6%	*12.0%*	*13.0%*
Long-Term Debt Ratio							47.8%	48.4%	50.1%	46.5%	51.3%	53.6%	56.8%	57.0%	55.8%	55.0%	*56.5%*	*57.0%*
Common Equity Ratio							52.2%	51.6%	49.9%	53.5%	48.7%	46.4%	43.2%	43.0%	44.2%	45.0%	*43.5%*	*43.0%*
Total Capital ($mill)							4329.0	4544.0	4842.0	4684.0	5323.0	5628.0	6265.0	6459.0	7513.0	8424.0	*9175*	*9900*
Net Plant ($mill)							6012.0	6434.0	6741.0	6887.0	7161.0	7539.0	8005.0	8465.0	9546.0	10345	*11070*	*11750*
Return on Total Cap'l							5.4%	5.6%	5.5%	5.8%	5.1%	5.6%	4.9%	4.9%	4.2%	5.0%	*5.0%*	*5.0%*
Return on Shr. Equity							7.6%	8.2%	8.4%	8.5%	8.3%	9.5%	9.0%	8.8%	7.0%	8.6%	*9.0%*	*9.0%*
Return on Com Equity E							7.6%	8.2%	8.4%	8.5%	8.3%	9.5%	9.0%	8.8%	7.0%	8.6%	*9.0%*	*9.0%*
Retained to Com Eq							3.3%	3.5%	3.6%	3.5%	3.1%	4.1%	3.5%	3.1%	1.6%	3.3%	*3.0%*	*3.0%*
All Div'ds to Net Prof							56%	57%	58%	59%	63%	57%	61%	64%	77%	61%	*65%*	*65%*

CAPITAL STRUCTURE as of 3/31/25
Total Debt $5031 mill. **Due in 5 Yrs** $763 mill.
LT Debt $4936 mill. **LT Interest** $208 mill.
Incl. $273 mill. finance leases.
(Total Interest Coverage: 2.6x)
Leases, Uncapitalized Annual rentals $26 mill.
Pension Assets-12/24 $484 mill.
Oblig. $612 mill.
Pfd Stock None

Common Stock 109,514,333 shs.
as of 4/18/25

MARKET CAP: $4.5 billion (Mid Cap)

ELECTRIC OPERATING STATISTICS

	2022	2023	2024
% Change Retail Sales (KWH)	+3.4	+.9	+1.3
Avg. Indust. Use (MWH)	22097	23052	24703
Avg. Indust. Revs. per KWH (¢)	5.23	5.85	6.59
Capacity at Peak (MW)	NA	NA	NA
Peak Load, Summer (MW)	4255	4498	4367
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+1.1	+.7	+1.6
Fixed Charge Cov. (%)	254	217	235

ANNUAL RATES of change (per sh)

	Past 10 Yrs.	Past 5 Yrs.	Est'd '22-'24 to '28-'30
Revenues	2.5%	5.5%	*3.5%*
"Cash Flow"	3.0%	2.0%	*5.5%*
Earnings	3.5%	3.0%	*6.5%*
Dividends	5.5%	5.5%	*5.5%*
Book Value	3.5%	3.0%	*4.5%*

QUARTERLY REVENUES ($ mill.)

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2022	626	591	743	687	2647
2023	748	648	802	725	2923
2024	929	758	929	824	3440
2025	928	*797*	*975*	*900*	*3600*
2026	*975*	*825*	*1020*	*930*	*3750*

EARNINGS PER SHARE A

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2022	.67	.72	.65	.70	2.74
2023	.80	.44	.46	.67	2.38
2024	1.21	.69	.90	.34	3.14
2025	.91	*.70*	*.95*	*.69*	*3.25*
2026	*1.00*	*.70*	*1.00*	*.70*	*3.40*

QUARTERLY DIVIDENDS PAID B ■ †

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	.4075	.4075	.43	.43	1.68
2022	.43	.43	.4525	.4525	1.77
2023	.4525	.4525	.475	.475	1.86
2024	.475	.475	.50	.50	1.95
2025	.50	.50	.525		

BUSINESS: Portland General Electric Company provides electricity to 950,000 customers in 51 cities in a 4,000-square-mile area of Oregon, including Portland and Salem (population: 1.9 million). The company is in the process of decommissioning the Trojan nuclear plant, which was closed in 1993. Electric revenue breakdown: residential, 51%; commercial, 33%; industrial, 16%; other, less than 1%. Generating sources: gas, 28%; wind, 16%; coal, 4%; hydro, 7%; purchased, 45%. Fuel costs: 41% of revenues. '24 reported depreciation rate: 3.5%. Has 2,915 full-time employees. Chair: James P. Torgerson. President and CEO: Maria M. Pope. Incorporated: Oregon. Address: 121 S.W. Salmon Street, Portland, OR 97204. Tel.: 503-464-8000. Internet: www.portlandgeneral.com.

Portland General Electric stock has been a weak performer lately. The results of the company's Oregon rate-case decision in December were disappointing, as the authorized return on equity (ROE) was reduced from 9.5% to 9.34%. Portland General was seeking an 8.6% across-the-board rate increase for the recoupment of investments made, but instead received a 5.5% residential hike and 7.7% commercial/industrial increase. Overall, Portland got a $98 million revenue lift, representing 54% of the requested amount. The rise helps, but up against higher interest and depreciation expenses and rising operations and maintenance costs, the company is targeting earnings of $3.13 to $3.33 per share this year. Our $3.25 estimate is slightly north of the midpoint of the range and still only represents 3.5% earnings-per-share growth. This is despite the company seeing solid demand trends (more below). Another factor potentially hurting share performance is the impact of January's wildfires in California on sentiment for Pacific Northwest utilities. Portland General by all accounts does a very good job with wildfire mitigation, but material adverse risks remain for operators whose territory spans densely forested areas.

Long-term electricity demand growth in the utility's service area is a plus. There's a cluster of high-tech companies occupying an area referred to as the "Silicon Forest" within Portland General's territory. Key employers there include Intel, Adobe, Microsoft, NTT Global, NVIDIA, Synopsys, and Stack Infrastructure. Portland also counts Microchip Technology, Lam Research, and ON Semiconductor, among others as commercial/industrial customers. Weather-adjusted demand has been rising at a solid pace from the semiconductor industry and data centers, which also provide a lift to the region's economy. The company is expecting load growth to average 2.5% to 3.5% for the foreseeable future.

This equity is ranked to track the year-ahead market. POR's dividend yield is more than a percentage point and a half above the 3.6% peer-group median. While total return prospects look appealing, investors do need to consider the wildfire risk in the Pacific Northwest.

Anthony J. Glennon *July 18, 2025*

(A) Diluted earnings. Excl. nonrecurring gains/(losses): '13, (42¢); '17, (19¢); '20, ($1.03); '22, (14¢); '23, (5¢); '24, (13¢). Quarterly EPS many not sum to full year due to rounding. Next earnings report due late July. **(B)** Dividends paid mid-Jan., Apr., July, and Oct. ■ Dividend reinvestment plan available. † Shareholder investment plan available. **(C)** Incl. deferred charges. In '24: $632 mill., $5.78/sh. **(D)** In mill. **(E)** Rate base: Net original cost. Rate allowed on common equity in '25: 9.34%. Regulatory Climate: Average.

Company's Financial Strength	B++
Stock's Price Stability	95
Price Growth Persistence	30
Earnings Predictability	85

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SOUTHERN COMPANY NYSE-SO

RECENT PRICE **90.75** | P/E RATIO **21.1** (Trailing: 22.4 Median: 17.0) | RELATIVE P/E RATIO **1.26** | DIV'D YLD **3.3%** | **VALUE LINE**

TIMELINESS 3 Raised 5/2/25
SAFETY 2 Lowered 2/21/14
TECHNICAL 3 Raised 4/4/25
BETA .75 (1.00 = Market)

18-Month Target Price Range

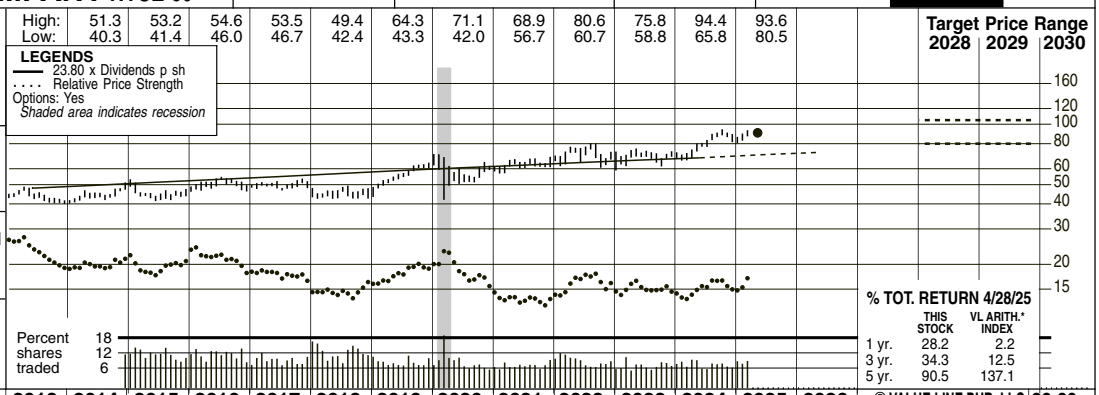
Low-High	Midpoint (% to Mid)
$69-$103	$86 (-5%)

2028-30 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	105	(+15%)	*7%*
Low	80	(-10%)	*1%*

Institutional Decisions

	2Q2024	3Q2024	4Q2024
to Buy	895	980	1095
to Sell	732	765	793
Hld's(000)	735543	829101	831264



2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	© VALUE LINE PUB. LLC	28-30
19.21	20.70	20.41	19.06	19.26	20.34	19.18	20.09	22.86	22.73	20.34	19.29	21.80	26.89	23.15	24.38	*24.90*	*25.90*	Revenues per sh	*28.55*
4.43	4.51	4.91	5.18	5.27	5.28	5.47	5.69	6.64	6.41	6.33	6.98	7.20	7.34	7.79	8.35	*8.50*	*8.80*	"Cash Flow" per sh	*9.80*
2.32	2.36	2.55	2.67	2.70	2.77	2.84	2.83	3.21	3.00	3.17	3.25	3.42	3.61	3.64	4.06	*4.30*	*4.60*	Earnings per sh [A]	*5.60*
1.73	1.80	1.87	1.94	2.01	2.08	2.15	2.22	2.30	2.38	2.46	2.54	2.62	2.70	2.78	2.86	*2.96*	*3.05*	Div'd Decl'd per sh [B] ■	*3.10*
5.70	4.85	5.23	5.54	6.16	6.58	6.22	7.38	7.37	7.74	7.17	7.04	6.83	7.87	8.88	8.84	*8.75*	*8.70*	Cap'l Spending per sh	*8.50*
18.15	19.21	20.32	21.09	21.43	21.98	22.59	25.00	23.98	23.92	26.11	26.48	26.30	27.93	28.82	29.85	*31.75*	*31.90*	Book Value per sh [C]	*32.25*
819.65	843.34	865.13	867.77	887.09	907.78	911.72	990.39	1007.6	1033.8	1053.3	1056.5	1060.0	1089.0	1091.0	1096.0	*1105.0*	*1110.0*	Common Shs Outst'g [D]	*1120.0*
13.5	14.9	15.8	17.0	16.2	16.0	15.8	17.8	15.5	15.1	17.6	17.9	18.4	19.6	19.1	19.6	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	*16.5*
.90	.95	.99	1.08	.91	.84	.80	.93	.78	.82	.94	.92	1.00	1.14	1.06	1.09			Relative P/E Ratio	*.90*
5.5%	5.1%	4.6%	4.3%	4.6%	4.7%	4.8%	4.4%	4.6%	5.3%	4.4%	4.4%	4.2%	4.1%	4.1%	3.4%			Avg Ann'l Div'd Yield	*3.6%*
17489	19896	23031	23495	21419	20375	23113	29279	25253	26724	*27500*	*28750*	Revenues ($mill)	*32000*
2647.0	2757.0	3269.0	3096.0	3354.0	3481.0	3670.0	3931.3	3976.0	4401.0	*4710*	*5035*	Net Profit ($mill)	*6270*
33.4%	28.5%	25.2%	21.3%	15.9%	14.3%	16.3%	18.9%	11.4%	14.5%	*15.0%*	*15.0%*	Income Tax Rate	*15.0%*
13.2%	11.9%	7.6%	6.8%	6.0%	6.6%	7.7%	8.0%	7.9%	8.0%	*8.0%*	*8.0%*	AFUDC % to Net Profit	*6.0%*
52.8%	61.5%	64.5%	62.0%	60.1%	61.5%	64.0%	63.0%	65.6%	64.4%	*64.0%*	*64.0%*	Long-Term Debt Ratio	*63.0%*
44.0%	35.7%	35.0%	37.6%	39.5%	38.1%	35.6%	36.5%	37.6%	36.8%	*36.0%*	*36.0%*	Common Equity Ratio	*37.0%*
46788	69359	68953	65750	69594	73336	78285	80558	83654	84373	*87500*	*90000*	Total Capital ($mill)	*93500*
61114	78446	79872	80797	83080	87634	91108	94570	99844	100028	*100500*	*100800*	Net Plant ($mill)	*110000*
6.6%	4.9%	5.9%	5.9%	6.0%	5.9%	5.8%	5.5%	4.6%	4.8%	*5.5%*	*5.5%*	Return on Total Cap'l	*6.5%*
12.0%	10.3%	13.3%	12.4%	12.1%	12.3%	13.0%	12.5%	12.6%	12.9%	*13.0%*	*13.0%*	Return on Shr. Equity	*14.5%*
12.6%	11.0%	13.4%	12.5%	12.1%	12.4%	13.1%	12.5%	12.6%	12.9%	*13.0%*	*13.0%*	Return on Com Equity [E]	*14.5%*
3.1%	2.5%	3.9%	2.6%	2.8%	2.8%	3.1%	3.0%	3.2%	3.4%	*3.5%*	*3.5%*	Retained to Com Eq	*5.0%*
76%	78%	72%	79%	77%	78%	76%	78%	77%	77%	*77%*	*77%*	All Div'ds to Net Prof	*67%*

CAPITAL STRUCTURE as of 12/31/24
Total Debt $63486 mill. **Due in 5 Yrs** $15427 mill.
LT Debt $58768 mill. **LT Interest** $1754 mill.
Incl. $215 mill. finance leases.
(LT interest earned: 3.3x)
Leases, Uncapitalized Annual rentals $307 mill.
Pension Assets-12/23 $14218 mill.
Oblig $16382 mill.
Pfd Stock $242 mill. **Pfd Div'd** $15 mill.
Incl. 10 mill. shs. 5.83% cum. pfd. ($25 stated value); 475,115 shs. 4.2%-5.44% cum. pfd. ($100 par).
Common Stock 1,096,802,197 shs.
MARKET CAP: $99.5 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2022	2023	2024
% Change Retail Sales (KWH)	+2.0	NA	NA
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Yearend (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+1.5	NA	NA
Fixed Charge Cov. (%)	275	NA	NA

ANNUAL RATES

of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '21-'23 to '28-'30
Revenues	- -	.5%	*6.0%*
"Cash Flow"	4.0%	4.5%	*5.0%*
Earnings	3.0%	3.0%	*6.5%*
Dividends	3.5%	3.5%	*3.5%*
Book Value	3.0%	2.5%	*3.5%*

QUARTERLY REVENUES (mill.)

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2022	6648	7206	8378	7047	29279
2023	6480	5748	6980	6045	25253
2024	6646	6463	7274	6341	26724
2025	*7100*	*6500*	*7400*	*6500*	*27500*
2026	*7350*	*6800*	*7700*	*6900*	*28750*

EARNINGS PER SHARE [A]

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2022	.97	1.07	1.31	.26	3.61
2023	.79	.79	1.42	.64	3.64
2024	1.03	1.10	1.43	.50	4.06
2025	*1.20*	*1.10*	*1.45*	*.55*	*4.30*
2026	*1.15*	*1.20*	*1.55*	*.70*	*4.60*

QUARTERLY DIVIDENDS PAID [B] ■

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	.64	.66	.66	.66	2.62
2022	.66	.68	.68	.68	2.70
2023	.68	.70	.70	.70	2.78
2024	.70	.72	.72	.72	2.86
2025	.72	.74			

BUSINESS: The Southern Company, through its subsidiaries, supplies electricity to 4.4 mill. customers in GA, AL, and MS. Also has a competitive generation business. Acq'd AGL Resources (renamed Southern Company Gas, 4.4 mill. customers in GA, NJ, IL, VA, & TN) 7/16. Sold Gulf Power 1/19. Electric revenue breakdown: residential, 43%; commercial, 35%; industrial, 21%; other, 1%. Generating sources: gas, 51%; coal, 19%; nuclear, 10%; other, 11%; purchased, 9%. Fuel costs: 26% of revenues. '24 reported deprec. rates (utility): 2.7%-3.4%. Has 27,300 employees. President and CEO: Chris Womack. Incorporated.: Delaware. Address: 30 Ivan Allen Jr. Blvd., N.W., Atlanta, Georgia 30308. Telephone: 404-506-0747. Internet: www.southerncompany.com.

We look for Southern Company's earnings to advance nicely in 2025 and 2026. The company was slated to report first-quarter earnings results shortly after this report went to press. Southern closed out 2024 on a strong note and should continue to benefit from rate relief and volume growth. Growing demand from data centers and population surges have driven electricity consumption to record highs. Accordingly, Southern raised its capital spending plan by 30%, to $63 billion through 2030, to meet the elevated jump in electricity demand. Our 2025 estimate, which remains unchanged, is at the high point of management's updated target of $4.20-$4.30 per share, reflecting 6% growth from last year's midpoint target. Long-term profit growth guidance remains at 5%-7%, but management has indicated the potential to reach the high end of that range. We have introduced our 2026 top- and bottom-line estimates of $28.75 billion and $4.60 per share, respectively.

Southern Company shares have performed strongly alongside recent broader market pressure. The stock price is up nearly 10% since the start of 2025 and has risen about 5% over the past three months. Utilities have recently served as a safe haven, outperforming the broader market, and Southern is performing better than almost all of its peers. This is a testament to its regional electricity volume growth, financial strength, safety, and consistent dividend payout.

The Board of Directors remains committed to boosting shareholder value. Indeed, the utility recently announced its 24th consecutive annual dividend increase. Southern declared a 3% quarterly dividend increase to $0.74 per share. The stock now carries a dividend yield of 3.3%.

Investors may want to take a closer look at these shares, especially given the current challenging macroeconomic environment. Southern offers strong defensive qualities, including fixed returns, a top-notch Price Stability score, an above-average (2) Safety rank, and a well-supported dividend payout. On the other hand, the recent quotation is already well within the 3- to 5-year Target Price Range.

Zachary Hodgkinson *May 9, 2025*

(A) Diluted EPS. Excl. nonrec. gain (losses): '09, (25¢); '13, (83¢); '14, (59¢); '15, (25¢); '16, (28¢); '17, ($2.37); '18, (78¢); '19, $1.30; '20, (17¢); '21, (54¢). Next earnings report due in Aug. **(B)** Div'ds paid in early Mar., June, Sept., and Dec. ■ Div'd reinvestment plan avail. **(C)** Incl. def'd charges. In '23: $17.35/sh. **(D)** In mill. **(E)** Rate base: AL, MS, fair value; FL, GA, orig. cost. Allowed return on common eq. (blended): 12.5%; earned on avg. com. eq., '21: 12.8%. Regulatory Climate: GA, AL Above Average; MS, FL Average.

Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	65
Earnings Predictability	90

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XCEL ENERGY NDQ-XEL

RECENT PRICE **67.88** | P/E RATIO **17.9** (Trailing: 19.7 Median: 20.0) | RELATIVE P/E RATIO **0.96** | DIV'D YLD **3.5%** | **VALUE LINE**

TIMELINESS 3 Raised 5/16/25
SAFETY 2 Lowered 1/19/24
TECHNICAL 1 Raised 5/23/25
BETA .70 (1.00 = Market)

18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$61-$91	$76 (10%)

2028-30 PROJECTIONS

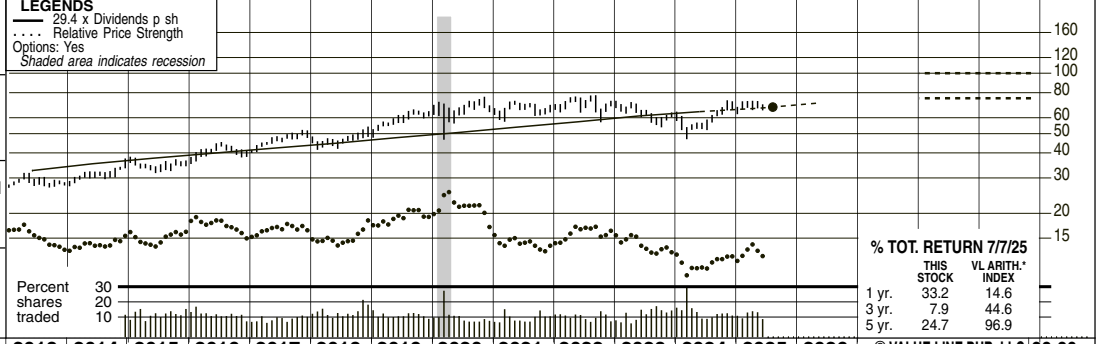
	Price	Gain	Ann'l Total Return
High	100	(+45%)	*13%*
Low	75	(+10%)	*6%*

Institutional Decisions

	3Q2024	4Q2024	1Q2025
to Buy	518	598	549
to Sell	408	372	449
Hld's(000)	503378	534272	495263

	37.6	38.3	45.4	52.2	54.1	66.1	76.4	72.9	77.7	73.0	73.4	73.0
High:												
Low:	27.3	31.8	35.2	40.0	41.5	47.7	46.6	57.2	56.9	53.7	46.8	62.6

LEGENDS
29.4 x Dividends p sh
Relative Price Strength
Options: Yes
Shaded area indicates recession



% TOT. RETURN 7/7/25

	THIS STOCK	VL ARITH.* INDEX
1 yr.	33.2	14.6
3 yr.	7.9	44.6
5 yr.	24.7	96.9

2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	© VALUE LINE PUB. LLC	28-30
21.08	21.38	21.90	20.76	21.92	23.11	21.72	21.90	22.46	22.44	21.98	21.45	24.69	27.86	25.60	23.40	*25.85*	*27.35*	Revenues per sh	*31.95*
3.48	3.51	3.79	4.00	4.10	4.28	4.56	5.04	5.47	5.92	6.25	6.61	7.08	7.81	7.96	8.43	*9.10*	*9.75*	"Cash Flow" per sh	*11.70*
1.49	1.56	1.72	1.85	1.91	2.03	2.10	2.21	2.30	2.47	2.64	2.79	2.96	3.17	3.35	3.50	*3.80*	*4.05*	Earnings per sh A	*5.00*
.97	1.00	1.03	1.07	1.11	1.20	1.28	1.36	1.44	1.52	1.62	1.72	1.83	1.95	2.08	2.19	*2.28*	*2.42*	Div'd Decl'd per sh B ■ †	*3.00*
3.91	4.60	4.53	5.27	6.82	6.33	7.26	6.42	6.54	7.70	8.05	9.99	7.80	8.44	10.55	12.82	*15.00*	*14.00*	Cap'l Spending per sh	*13.00*
15.92	16.76	17.44	18.19	19.21	20.20	20.89	21.73	22.56	23.78	25.24	27.12	28.70	30.34	31.74	33.99	*35.80*	*37.70*	Book Value per sh C	*43.70*
457.51	482.33	486.49	487.96	497.97	505.73	507.54	507.22	507.76	514.04	524.54	537.44	544.03	549.58	554.94	574.37	*580.00*	*585.00*	Common Shs Outst'g D	*595.00*
12.7	14.1	14.2	14.8	15.0	15.4	16.5	18.5	20.2	18.9	22.3	23.9	22.5	22.2	19.0	17.0	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	*17.5*
.85	.90	.89	.94	.84	.81	.83	.97	1.02	1.02	1.19	1.23	1.22	1.28	1.06	.90			Relative P/E Ratio	*.95*
5.1%	4.5%	4.2%	3.9%	3.9%	3.8%	3.7%	3.3%	3.1%	3.3%	2.7%	2.6%	2.8%	2.8%	3.3%	3.7%			Avg Ann'l Div'd Yield	*3.4%*
11024	11107	11404	11537	11529	11526	13431	15310	14206	13441	*15000*	*16000*	Revenues ($mill)	*19000*
1063.6	1123.4	1171.0	1261.0	1372.0	1473.0	1597.0	1736.0	1851.0	1969.0	*2205*	*2360*	Net Profit ($mill)	*2975*
35.8%	34.1%	30.7%	12.6%	8.5%	--	--	--	--	--	*NMF*	*NMF*	Income Tax Rate	*NMF*
7.7%	7.8%	9.4%	12.4%	8.3%	10.7%	6.2%	5.9%	7.7%	12.2%	*10.0%*	*10.0%*	AFUDC % to Net Profit	*9.0%*
54.1%	56.3%	55.9%	56.4%	56.8%	57.4%	58.2%	57.8%	58.6%	58.3%	*61.0%*	*61.5%*	Long-Term Debt Ratio	*61.0%*
45.9%	43.7%	44.1%	43.6%	43.2%	42.6%	41.8%	42.2%	41.4%	41.7%	*39.0%*	*38.5%*	Common Equity Ratio	*39.0%*
23092	25216	25975	28025	30646	34220	37391	39488	42529	46838	*53000*	*57500*	Total Capital ($mill)	*66500*
31206	32842	34329	36944	39483	42950	45457	48253	51642	57198	*63400*	*68000*	Net Plant ($mill)	*77800*
5.8%	5.7%	5.8%	5.7%	5.6%	5.4%	5.3%	5.5%	5.4%	5.5%	*5.5%*	*5.5%*	Return on Total Cap'l	*5.5%*
10.0%	10.2%	10.2%	10.3%	10.4%	10.1%	10.2%	10.4%	10.5%	10.1%	*10.5%*	*10.5%*	Return on Shr. Equity	*11.0%*
10.0%	10.2%	10.2%	10.3%	10.4%	10.1%	10.2%	10.4%	10.5%	10.1%	*10.5%*	*10.5%*	Return on Com Equity E	*11.0%*
4.3%	4.0%	3.9%	4.3%	4.4%	4.2%	4.2%	4.3%	4.3%	4.1%	*4.5%*	*4.5%*	Retained to Com Eq	*4.5%*
57%	61%	62%	58%	58%	58%	59%	58%	59%	60%	*60%*	*60%*	All Div'ds to Net Prof	*60%*

CAPITAL STRUCTURE as of 3/31/25
Total Debt $31218 mill. **Due in 5 Yrs** $3741 mill.
LT Debt $29396 mill. **LT Interest** $1290 mill.
Incl. $228 mill. finance leases.
(Total Interest Coverage: 2.6x)

Leases, Uncapitalized Annual rentals $277 mill.
Pension Assets-12/24 $2504 mill.
Oblig. $2752 mill.
Pfd Stock None

Common Stock 576,760,613 shs.
as of 4/17/25
MARKET CAP: $39.2 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2022	2023	2024
% Change Retail Sales (KWH)	+1.2	-1.6	-2.4
Resid'l Revs. per KWH (¢)	13.41	13.80	13.83
C & I Revs. per KWH (¢)	9.02	8.82	8.24
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	20346	20512	20343
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+1.0	+1.1	+1.2
Fixed Charge Cov. (%)	255	245	194

ANNUAL RATES of change (per sh)

	Past 10 Yrs.	Past 5 Yrs.	Est'd '22-'24 to '28-'30
Revenues	1.5%	3.0%	*3.5%*
"Cash Flow"	7.0%	6.5%	*6.5%*
Earnings	5.5%	6.0%	*7.0%*
Dividends	6.5%	6.5%	*6.5%*
Book Value	5.5%	6.0%	*5.5%*

QUARTERLY REVENUES ($ mill.)

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2022	3751	3424	4082	4053	15310
2023	4080	3022	3662	3442	14206
2024	3649	3028	3644	3120	13441
2025	3906	*3300*	*3994*	*3800*	*15000*
2026	*4125*	*3600*	*4225*	*4050*	*16000*

EARNINGS PER SHARE A

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2022	.70	.60	1.18	.69	3.17
2023	.76	.52	1.23	.83	3.35
2024	.89	.55	1.25	.81	3.50
2025	.84	*.66*	*1.38*	*.92*	*3.80*
2026	*.95*	*.70*	*1.44*	*.96*	*4.05*

QUARTERLY DIVIDENDS PAID B ■ †

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	.43	.4575	.4575	.4575	1.80
2022	.4575	.4875	.4875	.4875	1.92
2023	.4875	.52	.52	.52	2.05
2024	.52	.5475	.5475	.5475	2.16
2025	.5475	.57	.57		

BUSINESS: Xcel Energy Inc. is the parent of: Northern States Power Company (NSP), which supplies electricity to MN, WI, ND, SD & MI & gas to MN, WI, ND & MI; Public Service Company of Colorado (PSCo), which supplies electricity & gas to CO; & Southwestern Public Service Company (SPS), which supplies electricity to TX and NM. Customers: 3.9 mill. electric, 2.2 mill. gas. Electric revenues: resid'l, 32%; comm'l & ind'l, 49%; other, 19%. Purchases 35% of power, owns 65%. Total electric mix: wind, 33%; gas, 33%; coal, 15%, nuclear, 10%, solar/other, 9%. Fuel cost: 35% of revenues. '24 deprec. rate: 3.8%. Employs 11,380. Chrmn., President, and CEO: Robert Frenzel. Inc.: MN. Addr.: 414 Nicollet Mall, Minneapolis, MN 55401. Tel.: 612-330-5500. Int.: www.xcelenergy.com.

Xcel Energy was off to a bit of a slow start to the year, but will likely reach its bottom-line expectations. The last time Xcel's profits failed to surpass the previous year's level was 2005. The company has consistently delivered results within the targeted range management provides at the start of a new year. Xcel has a huge service area, encompassing sections of eight large states through its four wholly owned utility subsidiaries. That provides plenty of diversification, scale, and flexibility. In 2024, Xcel needed to rein in costs to deliver on-target financial results. Last year's $3.50 per share came in at the bottom of management's $3.50-$3.60 forecast, but that was largely due to fewer overall cooling and heating days than typical. (Retail electric volume was down 2.4% in 2024 despite a 1.2% rise in the customer base.) For this year, the aggregate comparison should be relatively easy, and we expect the company to make good on management's $3.75 to $3.85 earnings-per-share outlook. First-quarter profits were lower than the comparable year-ago figure, largely due to more scheduled maintenance work.

Prospects to late decade look good. Xcel's five-year capital expenditure plan is expected to deliver annual rate-base growth in excess of 9%, which should translate to 6%-8% share-earnings gains. Regulated prices set for electricity and natural gas delivery in ratepayers' bills result in revenue streams that provide the recoupment of capital expenditures plus an economic return on investment. Xcel's main focus of late has been on increasing its utility-owned generating capacity. Due to major wildfires in portions of its Colorado and Texas service areas, mitigation technologies will likely become a more prominent source of investment.

Xcel shares don't stand out at the recent valuation. A Colorado court case related to Xcel's alleged role in the Marshall fire of 2021 is due to commence this September. It may result in some headline risk later this year and a potential buying opportunity. It's difficult to say how that case will turn out, but we believe that it's doubtful Xcel will be liable for more than $1.5 billion, net of insurance. That level would be quite manageable in our view.

Anthony J. Glennon *July 18, 2025*

(A) Diluted EPS. Excl. nonrec. gain/(losses): '10, 5¢; '15, (16¢); '17, (5¢); '23, (14¢); '24, (6¢); gain/ (loss) on discontin'd ops.: '09, (1¢); '10, 1¢. Qtly. EPS may not sum to full yr. due to rounding. Next egs. report due late July.
(B) Div'ds typically paid mid-Jan., Apr., July, and Oct. ■ Div'd reinvestment plan available. † Shareholder investment plan available.
(C) Incl. intangibles. In '24: $3909 mill., $6.81/sh. **(D)** In mill. **(E)** Rate base: Varies. Rate allowed on common equity (blended): 9.6%. Regulatory Climate: Average.

Company's Financial Strength	A
Stock's Price Stability	95
Price Growth Persistence	55
Earnings Predictability	100

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Valley Energy, Inc. / Citizens' Electric Company of Lewisburg, PA / Wellsboro Electric Company
Indicated Common Equity Cost Rate
Through Use of a Risk Premium Model
Using an Adjusted Total Market Approach

Line No.		Proxy Group of Eight Natural Gas Distribution Companies	Proxy Group of Fourteen Electric Companies
1.	Prospective Yield on Aaa Rated Corporate Bonds (1)	5.23 %	5.23 %
2.	Adjustment to Reflect Yield Spread Between Aaa Rated Corporate Bonds and A2 Rated Public Utility Bonds (2)	0.48	0.48
3.	Adjusted Prospective Yield on A2 Rated Public Utility Bonds	5.71 %	5.71 %
4.	Adjustment to Reflect Bond Rating Difference of Proxy Group	0.06 (3)	0.13 (4)
5.	Adjusted Bond Yield	5.77 %	5.84 %
6.	Equity Risk Premium (5)	4.95	4.86
7.	Risk Premium Derived Common Equity Cost Rate	10.72 %	10.70 %

Notes: (1) Consensus forecast of Moody's Aaa Rated Corporate bonds from Blue Chip Financial Forecasts (see pages 32 and 33 of this Schedule).
(2) The average yield spread of A2 rated public utility bonds over Aaa rated corporate bonds of 0.48% from page 27 of this Schedule.
(3) Adjustment to reflect the A3 Moody's LT issuer rating of the Proxy Group of Eight Natural Gas Distribution Companies as shown on page 28 of this Schedule. The 0.06% upward adjustment is derived by taking 1/3 of the spread between A2 and Baa2 Public Utility Bonds (1/3 * 0.19% = 0.06%) as derived from page 27 of this Schedule.
(4) Adjustment to reflect the Baa1 Moody's LT issuer rating of the Proxy Group of Fourteen Electric Companies as shown on page 28 of this Schedule. The 0.13% upward adjustment is derived by taking 2/3 of the spread between A2 and Baa2 Public Utility Bonds (2/3 * 0.19% = 0.13%) as derived from page 27 of this Schedule.
(5) From page 30 of this Schedule.

Valley Energy, Inc. / Citizens' Electric Company of Lewisburg, PA / Wellsboro Electric Company
Interest Rates and Bond Spreads for
Moody's Corporate and Public Utility Bonds

Selected Bond Yields

	[1] Aaa Rated Corporate Bond	[2] A2 Rated Public Utility Bond	[3] Baa2 Rated Public Utility Bond
Jun-2025	5.46 %	5.93 %	6.12 %
May-2025	5.54	6.05	6.23
Apr-2025	5.45	5.91	6.11
Average	5.48 %	5.96 %	6.15 %

Selected Bond Spreads

A2 Rated Public Utility Bonds Over Aaa Rated Corporate Bonds:	0.48 % (1)
Baa2 Rated Public Utility Bonds Over A2 Rated Public Utility Bonds:	0.19 % (2)

Notes:
(1) Column [2] - Column [1].
(2) Column [3] - Column [2].

Source of Information:
Bloomberg Professional Services

Valley Energy, Inc. / Citizens' Electric Company of Lewisburg, PA / Wellsboro Electric Company
Comparison of Long-Term Issuer Ratings for the
Proxy Group of Eight Natural Gas Distribution Companies and Proxy Group of Fourteen Electric Companies

	Moody's Long-Term Issuer Rating July 2025		Standard & Poor's Long-Term Issuer Rating July 2025	
Proxy Group of Eight Natural Gas Distribution Companies	Long-Term Issuer Rating (1)	Numerical Weighting (2)	Long-Term Issuer Rating (1)	Numerical Weighting (2)
Atmos Energy Corporation	A2	6.0	A-	7.0
Chesapeake Utilities Corporation	NR	- -	NR	- -
New Jersey Resources Corporation	A1	5.0	NR	- -
NiSource Inc.	Baa1	8.0	BBB+	8.0
Northwest Natural Holding Company	Baa1	8.0	A+	5.0
ONE Gas, Inc.	A3	7.0	A-	7.0
Southwest Gas Holdings, Inc.	Baa1	8.0	BBB	9.0
Spire Inc.	A1/A2	5.5	BBB+	8.0
Average	A3	6.8	A-	7.3

Proxy Group of Fourteen Electric Companies	Long-Term Issuer Rating (1)	Numerical Weighting (2)	Long-Term Issuer Rating (1)	Numerical Weighting (2)
Alliant Energy Corporation	Baa1	8.0	A-/BBB+	7.5
American Electric Power Corporation	Baa2	9.0	BBB+	8.0
Ameren Corporation	A3	7.0	BBB+	8.0
Duke Energy Corporation	A3	7.0	BBB+	8.0
Edison International	Baa1	8.0	BBB	9.0
Entergy Corporation	Baa1	8.0	BBB+	8.0
Evergy, Inc.	Baa1/Baa2	8.5	BBB+	8.0
FirstEnergy Corporation	Baa1	8.0	BBB+	8.0
IDACORP, Inc.	Baa1	8.0	BBB	9.0
OGE Energy Corporation	A3	7.0	A-	7.0
Pinnacle West Capital Corporation	Baa1	8.0	BBB+	8.0
Portland General Electric Company	A3	7.0	BBB+	8.0
Southern Company	A2	6.0	A-	7.0
Xcel Energy, Inc.	A3	7.0	BBB+	8.0
Average	Baa1	7.6	BBB+	8.0

Notes:
(1) Ratings are that of the average of each company's utility operating subsidiaries.
(2) From page 29 of this Schedule.

Source Information: Moody's Investors Service
Standard & Poor's Global Utilities Rating Service

Numerical Assignment for Moody's and Standard & Poor's Bond Ratings

Moody's Bond Rating	Numerical Bond Weighting	Standard & Poor's Bond Rating
Aaa	1	AAA
Aa1	2	AA+
Aa2	3	AA
Aa3	4	AA-
A1	5	A+
A2	6	A
A3	7	A-
Baa1	8	BBB+
Baa2	9	BBB
Baa3	10	BBB-
Ba1	11	BB+
Ba2	12	BB
Ba3	13	BB-
B1	14	B+
B2	15	B
B3	16	B-

Valley Energy, Inc. / Citizens' Electric Company of Lewisburg, PA / Wellsboro Electric Company
Judgment of Equity Risk Premium for the
Proxy Group of Eight Natural Gas Distribution Companies and Proxy Group of Fourteen Electric Companies

Line No.		Proxy Group of Eight Natural Gas Distribution Companies	Proxy Group of Fourteen Electric Companies
1.	Calculated equity risk premium based on the total market using the beta approach (1)	5.27 %	4.95 %
2.	Mean equity risk premium based on a study using the holding period returns of public utilities with A2 rated bonds (2)	4.85	4.85
3.	Predicted Equity Risk Premium Based on Regression Analysis of 850 Fully-Litigated Natural Gas Rate Cases (3)	4.74	NA
4.	Predicted Equity Risk Premium Based on Regression Analysis of 1,262 Fully-Litigated Electric Rate Cases (4)	NA	4.78
5.	Average equity risk premium	4.95 %	4.86 %

Notes: (1) From page 31 of this Schedule.
(2) From page 34 of this Schedule.
(3) From page 35 of this Schedule.
(3) From page 36 of this Schedule.

Valley Energy, Inc. / Citizens' Electric Company of Lewisburg, PA / Wellsboro Electric Company
Derivation of Equity Risk Premium Based on the Total Market Approach
Using the Beta for the
Proxy Group of Eight Natural Gas Distribution Companies and Proxy Group of Fourteen Electric Companies

Line No.	Equity Risk Premium Measure	Proxy Group of Eight Natural Gas Distribution Companies	Proxy Group of Fourteen Electric Companies
1.	Kroll Equity Risk Premium (1)	6.10 %	6.10 %
2.	Regression on Kroll Risk Premium Data (2)	6.97	6.97
3.	Kroll Equity Risk Premium based on PRPM (3)	8.08	8.08
4	Equity Risk Premium Based on Value Line Summary and Index (4)	7.90	7.90
5.	Equity Risk Premium Based on Bloomberg, Value Line, and S&P Global Market Intelligence S&P 500 Companies (5)	10.92	10.92
6.	Conclusion of Equity Risk Premium	7.99 %	7.99 %
7.	Adjusted Beta (6)	0.66	0.62
8.	Forecasted Equity Risk Premium	5.27 %	4.95 %

Notes:

(1) Based on the arithmetic mean historical monthly returns on large company common stocks from Kroll Cost of Capital Navigator and Bloomberg Professional Services minus the arithmetic mean monthly yield of Moody's average Aaa and Aa2 corporate bonds from 1928-2024.

(2) This equity risk premium is based on a regression of the monthly equity risk premiums of large company common stocks relative to Moody's average Aaa and Aa2 rated corporate bond yields from 1928-2024 referenced in Note 1 above. Using the equation generated from the regression, an expected equity risk premium is calculated using the average consensus forecast of Aaa corporate bonds of 5.23% (from page 26 of this Schedule).

(3) The Predictive Risk Premium Model (PRPM) is discussed in the accompanying direct testimony. The Ibbotson equity risk premium based on the PRPM is derived by applying the PRPM to the monthly risk premiums between Ibbotson large company common stock monthly returns and average Aaa and Aa corporate monthly bond yields, from January 1928 through June 2025.

(4) The equity risk premium based on the Value Line Summary and Index is derived by subtracting the average consensus forecast of Aaa corporate bonds of 5.23% (from page 26 of this Schedule) from the projected 3-5 year total annual market return of 13.13% (described fully in note 1 on page 38 of this Schedule).

(5) Using data from the Bloomberg Professional Services, Value Line, and S&P Global Market Intelligence for the S&P 500, an expected total return of 16.15% was derived based upon expected dividend yields as a proxy for income returns and long-term earnings growth estimates as a proxy for capital appreciation. Subtracting the average consensus forecast of Aaa corporate bonds of 5.23% results in an expected equity risk premium of 10.92%.

(6) Average of mean and median beta for each proxy group from page 37 of this Schedule.

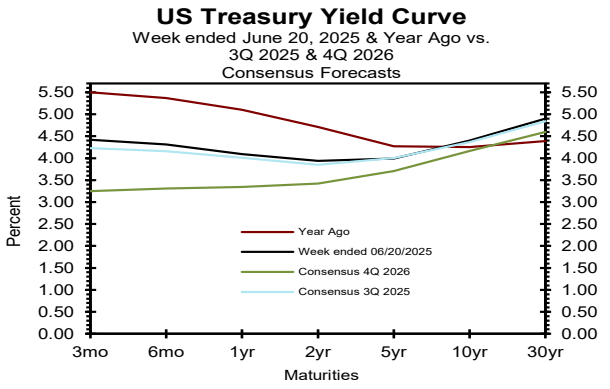
Sources of Information:

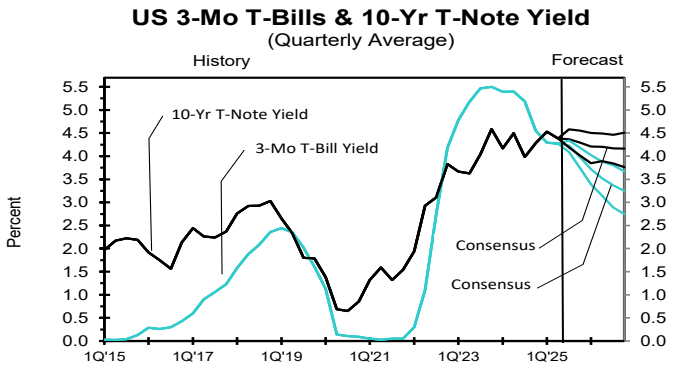
Kroll Cost of Capital Navigator
Industrial Manual and Mergent Bond Record Monthly Update.
Value Line Summary and Index
Blue Chip Financial Forecasts, June 2, 2025 and July 1, 2025
S&P Capital IQ
Bloomberg Professional Services

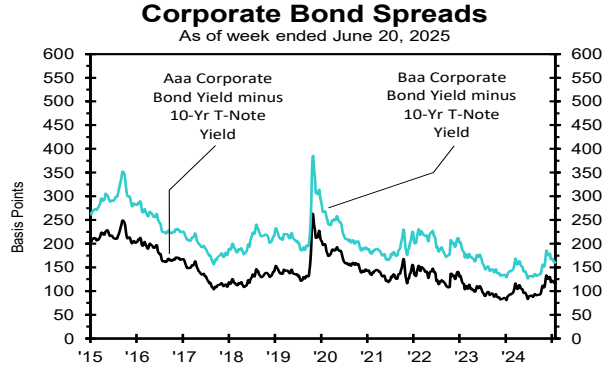
Consensus Forecasts of U.S. Interest Rates and Key Assumptions

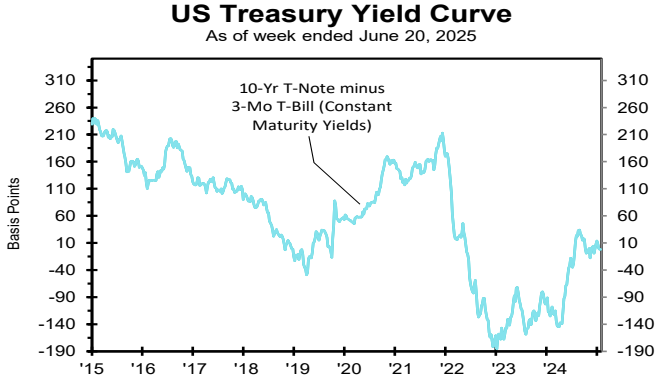
	History								Consensus Forecasts-Quarterly Avg.					
	Average For Week Ending				Average For Month			*Latest Qtr*	3Q	4Q	1Q	2Q	3Q	4Q
Interest Rates	Jun 20	Jun 13	Jun 6	May 30	May	Apr	Mar	2Q 2025*	2025	2025	2026	2026	2026	2026
Federal Funds Rate	4.33	4.33	4.33	4.33	4.33	4.33	4.33	4.33	**4.3**	**4.1**	**3.8**	**3.6**	**3.4**	**3.3**
Prime Rate	7.50	7.50	7.50	7.50	7.50	7.50	7.50	7.50	**7.4**	**7.2**	**6.9**	**6.7**	**6.6**	**6.4**
SOFR	4.30	4.28	4.31	4.32	4.30	4.35	4.33	4.32	**4.3**	**4.1**	**3.8**	**3.6**	**3.4**	**3.2**
Commercial Paper, 1-mo.	4.33	4.33	4.32	4.32	4.32	4.34	4.32	4.33	**4.3**	**4.0**	**3.8**	**3.6**	**3.4**	**3.3**
Treasury bill, 3-mo.	4.42	4.45	4.44	4.36	4.36	4.32	4.34	4.37	**4.2**	**4.0**	**3.7**	**3.5**	**3.4**	**3.3**
Treasury bill, 6-mo.	4.31	4.31	4.30	4.36	4.30	4.20	4.27	4.27	**4.2**	**3.9**	**3.7**	**3.6**	**3.4**	**3.3**
Treasury bill, 1 yr.	4.09	4.10	4.10	4.14	4.09	3.95	4.06	4.04	**4.0**	**3.8**	**3.6**	**3.5**	**3.4**	**3.3**
Treasury note, 2 yr.	3.94	3.96	3.95	3.92	3.92	3.78	3.97	3.87	**3.9**	**3.7**	**3.5**	**3.5**	**3.4**	**3.4**
Treasury note, 5 yr.	3.99	4.04	4.02	4.01	4.02	3.91	4.04	3.97	**4.0**	**3.9**	**3.8**	**3.8**	**3.7**	**3.7**
Treasury note, 10 yr.	4.40	4.43	4.44	4.44	4.42	4.28	4.28	4.37	**4.4**	**4.3**	**4.2**	**4.2**	**4.2**	**4.2**
Treasury note, 30 yr.	4.90	4.91	4.94	4.94	4.90	4.71	4.60	4.84	**4.8**	**4.7**	**4.7**	**4.7**	**4.6**	**4.6**
Corporate Aaa bond	5.59	5.60	5.64	5.66	5.66	5.56	5.38	5.61	**5.5**	**5.4**	**5.3**	**5.2**	**5.1**	**5.1**
Corporate Baa bond	6.01	6.02	6.08	6.12	6.14	6.06	5.81	6.08	**6.3**	**6.2**	**6.1**	**6.0**	**5.9**	**5.9**
State & Local bonds	4.43	4.46	4.49	4.47	4.47	4.50	4.22	4.47	**4.6**	**4.5**	**4.4**	**4.3**	**4.3**	**4.3**
Home mortgage rate	6.81	6.84	6.85	6.89	6.82	6.73	6.65	6.79	**6.8**	**6.6**	**6.5**	**6.4**	**6.3**	**6.3**
	History								Consensus Forecasts-Quarterly					
	3Q	4Q	1Q	2Q	3Q	4Q	1Q	2Q	3Q	4Q	1Q	2Q	3Q	4Q
Key Assumptions	2023	2023	2024	2024	2024	2024	2025	2025**	2025	2025	2026	2026	2026	2026
Fed's AFE $ Index	115.0	116.6	115.5	117.3	114.9	117.9	119.8	113.2	**112.6**	**112.3**	**112.1**	**112.0**	**111.9**	**111.8**
Real GDP	4.4	3.2	1.6	3.0	3.1	2.4	-0.5	1.3	**0.7**	**0.9**	**1.6**	**1.9**	**1.9**	**2.1**
GDP Price Index	3.2	1.5	3.0	2.5	1.9	2.3	3.8	2.9	**3.3**	**2.9**	**2.6**	**2.2**	**2.2**	**2.2**
Consumer Price Index	3.5	2.8	3.7	2.8	1.4	3.0	3.8	2.7	**3.7**	**3.2**	**2.8**	**2.5**	**2.4**	**2.4**
PCE Price Index	2.7	1.7	3.4	2.5	1.5	2.4	3.7	2.7	**3.5**	**3.0**	**2.7**	**2.4**	**2.2**	**2.2**

Forecasts for interest rates and the Federal Reserve's Advanced Foreign Economies Index represent averages for the quarter. Forecasts for Real GDP, GDP Price Index, CPI and PCE Price Index are seasonally adjusted annual rates of change (saar). Individual panel members' forecasts are on pages 4 through 9. Historical data: Treasury rates from the Federal Reserve Board's H.15; AAA-AA and A-BBB corporate bond yields from Bank of America-Merrill Lynch and are 15+ years, yield to maturity; State and local bond yields from Bank of America-Merrill Lynch, A-rated, yield to maturity; Mortgage rates from Freddie Mac, 30-year, fixed; SOFR from the New York Fed. *Interest rate data for 2Q 2025 based on historical data through the week ended June 20. **Data for 2Q 2025 for the Fed's AFE $ Index based on data through the week ended June 20. Figures for 2Q 2025 Real GDP, GDP Chained Price Index, Consumer Price Index, and PCE Price Index are consensus forecasts from the June 2025 survey.









Long-Range Survey:

The table below contains results of our semi-annual long-range CONSENSUS survey. There are also Top 10 and Bottom 10 averages for each variable. Shown are estimates for the years 2026 through 2031 and averages for the five-year periods 2027-2031 and 2032-2036. Apply these projections cautiously. Few economic, demographic and political forces can be evaluated accurately over such long time spans.

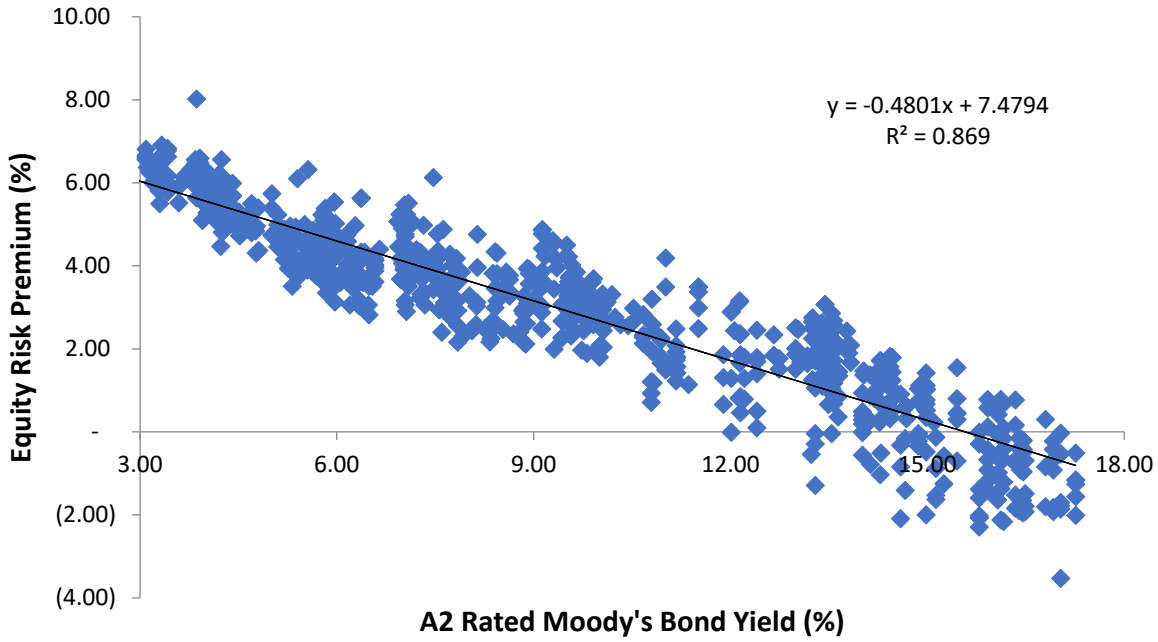
		Average For The Year						Five-Year Averages	
		2026	2027	2028	2029	2030	2031	2027-2031	2032-2036
1. Federal Funds Rate	**CONSENSUS**	**3.4**	**3.2**	**3.2**	**3.2**	**3.1**	**3.1**	**3.2**	**3.1**
	Top 10 Average	3.7	3.5	3.4	3.4	3.4	3.4	3.4	3.4
	Bottom 10 Average	3.1	3.0	2.9	2.9	2.8	2.9	2.9	2.8
2. Prime Rate	**CONSENSUS**	**6.5**	**6.4**	**6.3**	**6.3**	**6.2**	**6.2**	**6.3**	**6.2**
	Top 10 Average	6.7	6.6	6.5	6.6	6.5	6.5	6.5	6.5
	Bottom 10 Average	6.2	6.2	6.0	6.0	5.9	5.9	6.0	5.9
3. SOFR	**CONSENSUS**	**3.4**	**3.3**	**3.2**	**3.1**	**3.1**	**3.1**	**3.2**	**3.1**
	Top 10 Average	3.6	3.4	3.3	3.3	3.3	3.3	3.3	3.3
	Bottom 10 Average	3.2	3.2	3.0	2.9	2.9	2.9	3.0	2.8
4. Commercial Paper, 1-Mo	**CONSENSUS**	**3.4**	**3.3**	**3.2**	**3.1**	**3.1**	**3.1**	**3.2**	**3.1**
	Top 10 Average	3.5	3.4	3.3	3.2	3.2	3.2	3.3	3.3
	Bottom 10 Average	3.3	3.3	3.1	3.0	3.0	3.0	3.1	2.9
5. Treasury Bill Yield, 3-Mo	**CONSENSUS**	**3.3**	**3.2**	**3.2**	**3.1**	**3.1**	**3.1**	**3.1**	**3.1**
	Top 10 Average	3.6	3.4	3.4	3.4	3.3	3.3	3.4	3.3
	Bottom 10 Average	3.1	2.9	2.9	2.8	2.8	2.8	2.9	2.8
6. Treasury Bill Yield, 6-Mo	**CONSENSUS**	**3.3**	**3.2**	**3.2**	**3.1**	**3.1**	**3.1**	**3.2**	**3.1**
	Top 10 Average	3.6	3.4	3.4	3.3	3.3	3.3	3.3	3.3
	Bottom 10 Average	3.1	3.0	3.0	2.9	2.9	2.9	3.0	2.8
7. Treasury Bill Yield, 1-Yr	**CONSENSUS**	**3.3**	**3.3**	**3.3**	**3.2**	**3.2**	**3.2**	**3.2**	**3.2**
	Top 10 Average	3.6	3.5	3.4	3.4	3.4	3.4	3.4	3.4
	Bottom 10 Average	3.1	3.1	3.1	3.1	3.0	3.0	3.1	3.0
8. Treasury Note Yield, 2-Yr	**CONSENSUS**	**3.4**	**3.4**	**3.5**	**3.4**	**3.4**	**3.4**	**3.4**	**3.4**
	Top 10 Average	3.7	3.6	3.7	3.6	3.6	3.6	3.6	3.6
	Bottom 10 Average	3.1	3.2	3.2	3.2	3.2	3.2	3.2	3.1
9. Treasury Note Yield, 5-Yr	**CONSENSUS**	**3.7**	**3.7**	**3.7**	**3.7**	**3.7**	**3.7**	**3.7**	**3.7**
	Top 10 Average	3.9	3.9	3.9	3.9	3.9	3.9	3.9	4.0
	Bottom 10 Average	3.4	3.5	3.5	3.5	3.4	3.4	3.5	3.4
10. Treasury Note Yield, 10-Yr	**CONSENSUS**	**4.0**	**4.1**	**4.0**	**4.0**	**4.0**	**4.0**	**4.0**	**4.0**
	Top 10 Average	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3
	Bottom 10 Average	3.8	3.9	3.8	3.8	3.8	3.8	3.8	3.8
11. Treasury Bond Yield, 30-Yr	**CONSENSUS**	**4.5**	**4.4**	**4.4**	**4.3**	**4.3**	**4.3**	**4.4**	**4.3**
	Top 10 Average	4.7	4.7	4.6	4.6	4.6	4.6	4.6	4.7
	Bottom 10 Average	4.2	4.3	4.1	4.1	4.1	4.1	4.1	4.1
12. Corporate Aaa Bond Yield	**CONSENSUS**	**5.2**	**5.2**	**5.2**	**5.1**	**5.1**	**5.1**	**5.1**	**5.1**
	Top 10 Average	5.4	5.5	5.4	5.4	5.4	5.4	5.4	5.4
	Bottom 10 Average	5.0	5.0	4.9	4.9	4.9	4.9	4.9	4.9
13. Corporate Baa Bond Yield	**CONSENSUS**	**6.0**	**6.0**	**6.0**	**6.0**	**6.0**	**6.0**	**6.0**	**6.0**
	Top 10 Average	6.3	6.3	6.3	6.3	6.3	6.3	6.3	6.3
	Bottom 10 Average	5.8	5.9	5.8	5.8	5.8	5.7	5.8	5.8
14. State & Local Bonds Yield	**CONSENSUS**	**4.3**	**4.3**	**4.3**	**4.2**	**4.2**	**4.2**	**4.3**	**4.1**
	Top 10 Average	4.5	4.5	4.5	4.4	4.4	4.4	4.4	4.4
	Bottom 10 Average	4.1	4.2	4.1	4.1	4.1	4.1	4.1	3.8
15. Home Mortgage Rate	**CONSENSUS**	**6.2**	**6.2**	**6.1**	**6.0**	**6.0**	**6.0**	**6.1**	**5.9**
	Top 10 Average	6.4	6.4	6.4	6.3	6.3	6.3	6.3	6.3
	Bottom 10 Average	5.9	6.0	5.8	5.8	5.8	5.7	5.8	5.6
A. Fed's AFE Nominal $ Index	**CONSENSUS**	**113.3**	**112.7**	**112.7**	**112.2**	**111.7**	**111.3**	**112.1**	**110.8**
	Top 10 Average	114.2	113.3	113.4	112.9	112.5	112.2	112.8	112.4
	Bottom 10 Average	112.2	111.9	112.0	111.3	110.7	110.3	111.3	109.1
		Year-Over-Year, % Change						Five-Year Averages	
		2026	2027	2028	2029	2030	2031	2027-2031	2032-2036
B. Real GDP	**CONSENSUS**	**1.5**	**1.9**	**2.0**	**2.0**	**1.9**	**2.0**	**2.0**	**1.9**
	Top 10 Average	1.9	2.1	2.2	2.2	2.2	2.2	2.2	2.1
	Bottom 10 Average	1.1	1.8	1.8	1.8	1.7	1.7	1.8	1.8
C. GDP Chained Price Index	**CONSENSUS**	**2.4**	**2.2**	**2.1**	**2.1**	**2.1**	**2.1**	**2.1**	**2.1**
	Top 10 Average	2.6	2.3	2.2	2.2	2.2	2.2	2.2	2.2
	Bottom 10 Average	2.1	2.0	2.0	2.0	2.0	2.0	2.0	2.0
D. Consumer Price Index	**CONSENSUS**	**2.5**	**2.2**	**2.2**	**2.1**	**2.1**	**2.2**	**2.2**	**2.2**
	Top 10 Average	2.9	2.4	2.3	2.3	2.3	2.3	2.3	2.3
	Bottom 10 Average	2.1	2.0	2.0	2.0	2.0	2.0	2.0	2.1
E. PCE Price Index	**CONSENSUS**	**2.4**	**2.0**	**2.0**	**1.9**	**1.9**	**1.9**	**1.9**	**1.9**
	Top 10 Average	2.8	2.3	2.2	2.1	2.1	2.1	2.2	2.1
	Bottom 10 Average	2.1	1.8	1.8	1.8	1.7	1.8	1.8	1.8

Projected Market Appreciation of the S&P Utility Index
Derivation of Mean Equity Risk Premium Based Studies
Using Holding Period Returns and
Projected Market Appreciation of the S&P Utility Index

Line No.		Implied Equity Risk Premium
1.	Historical Equity Risk Premium (1)	4.16 %
2.	Regression of Historical Equity Risk Premium (2)	4.82
3	Forecasted Equity Risk Premium Based on PRPM (3)	4.39
4.	Forecasted Equity Risk Premium based on Projected Total Return on the S&P Utilities Index (Bloomberg, Value Line, and S&P Capital IQ Data) (4)	6.02
5.	Average Equity Risk Premium (5)	4.85 %

Notes:
(1) Based on S&P Public Utility Index monthly total returns and Moody's Public Utility Bond average monthly yields from 1928-2024. Holding period returns are calculated based upon income received (dividends and interest) plus the relative change in the market value of a security over a one-year holding period.
(2) This equity risk premium is based on a regression of the monthly equity risk premiums of the S&P Utility Index relative to Moody's A2 rated public utility bond yields from 1928 - 2024 referenced in note 1 above. Using the equation generated from the regression, an expected equity risk premium is calculated using the prospective A2 rated public utility bond yield of 5.71% (from line 3, page 26 of this Schedule).
(3) The Predictive Risk Premium Model (PRPM) is applied to the risk premium of the monthly total returns of the S&P Utility Index and the monthly yields on Moody's A2 rated public utility bonds from January 1928 - June 2025.
(4) Using data from Bloomberg, Value Line, and S&P Capital IQ for the S&P Utilities Index, an expected return of 11.73% was derived based on expected dividend yields as a proxy for income returns and long-term growth estimates as a proxy for market appreciation. Subtracting the expected A2 rated public utility bond yield of 5.71%, calculated on line 3 of page 26 of this Schedule results in an equity risk premium of 6.02%. (11.73% - 5.71% = 6.02%).
(5) Average of lines 1 through 4.

Valley Energy, Inc. / Citizens' Electric Company of Lewisburg, PA / Wellsboro Electric Company
Prediction of Equity Risk Premiums Relative to
Moody's A2 Rated Utility Bond Yields - Natural Gas Utilities



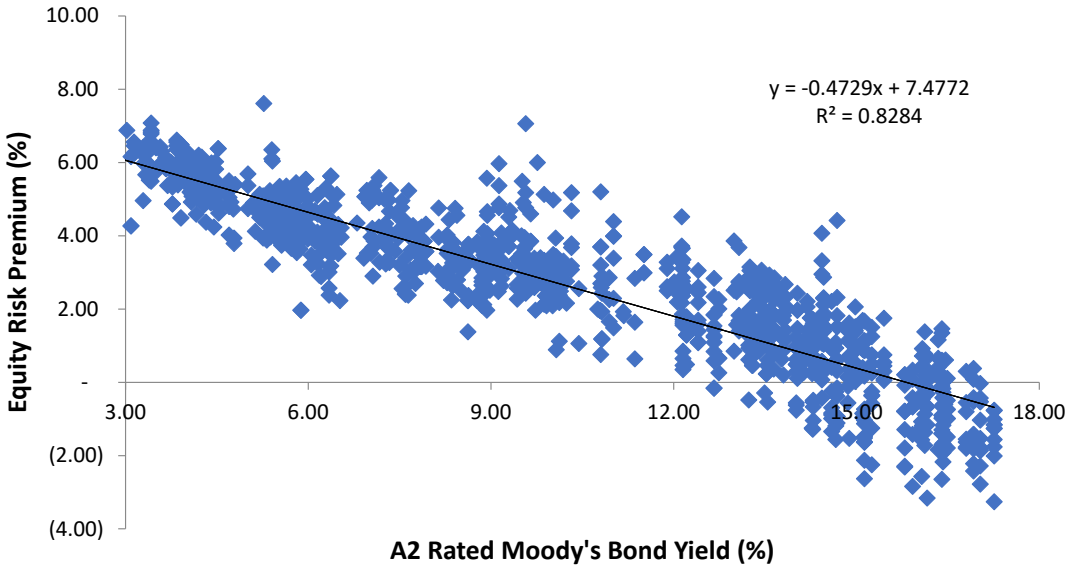
Constant	Slope	Prospective A2 Rated Utility Bond (1)	Equity Risk Premium
7.4794 %	-0.480	5.71 %	4.74 %

Notes:

(1) From line 3 of page 26 of this Schedule.

Source of Information: Regulatory Research Associates.

Valley Energy, Inc. / Citizens' Electric Company of Lewisburg, PA / Wellsboro Electric Company
Prediction of Equity Risk Premiums Relative to
Moody's A2 Rated Utility Bond Yields - Electric Utilities



Constant	Slope	Prospective A2 Rated Utility Bond (1)	Equity Risk Premium
7.4772 %	-0.4729	5.71 %	4.78 %

Notes:

(1) From line 3 of page 26 of this Schedule.

Source of Information: Regulatory Research Associates.

Valley Energy, Inc. / Citizens' Electric Company of Lewisburg, PA / Wellsboro Electric Company
Indicated Common Equity Cost Rate Through Use
of the Traditional Capital Asset Pricing Model (CAPM) and Empirical Capital Asset Pricing Model (ECAPM)

Proxy Group of Eight Natural Gas Distribution Companies

	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]
Proxy Group of Eight Natural Gas Distribution Companies	Value Line Adjusted Beta	Bloomberg Adjusted Beta	Average Beta	Market Risk Premium (1)	Risk-Free Rate (2)	Traditional CAPM Cost Rate	ECAPM Cost Rate	Indicated Common Equity Cost Rate (3)
Atmos Energy Corporation	0.75	0.52	0.63	8.86 %	4.60 %	10.18 %	11.00 %	10.59 %
Chesapeake Utilities Corporation	0.75	0.48	0.62	8.86	4.60	10.09	10.93	10.51
New Jersey Resources Corporation	0.85	0.47	0.66	8.86	4.60	10.45	11.20	10.82
NiSource Inc.	0.85	0.59	0.72	8.86	4.60	10.98	11.60	11.29
Northwest Natural Holding Company	0.80	0.52	0.66	8.86	4.60	10.45	11.20	10.82
ONE Gas, Inc.	0.80	0.50	0.65	8.86	4.60	10.36	11.13	10.75
Southwest Gas Holdings, Inc.	0.80	0.63	0.72	8.86	4.60	10.98	11.60	11.29
Spire Inc.	0.80	0.51	0.65	8.86	4.60	10.36	11.13	10.75
Mean			0.66			10.48 %	11.23 %	10.85 %
Median			0.66			10.40 %	11.17 %	10.79 %
Average of Mean and Median			0.66			10.44 %	11.20 %	10.82 %

Proxy Group of Fourteen Electric Companies

	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]
Proxy Group of Fourteen Electric Companies	Value Line Adjusted Beta	Bloomberg Adjusted Beta	Average Beta	Market Risk Premium (1)	Risk-Free Rate (2)	Traditional CAPM Cost Rate	ECAPM Cost Rate	Indicated Common Equity Cost Rate (3)
Alliant Energy Corporation	0.80	0.47	0.63	8.86 %	4.60 %	10.18 %	11.00 %	10.59 %
American Electric Power Corporation	0.70	0.40	0.55	8.86	4.60	9.47	10.47	9.97
Ameren Corporation	0.80	0.49	0.64	8.86	4.60	10.27	11.07	10.67
Duke Energy Corporation	0.70	0.32	0.51	8.86	4.60	9.12	10.20	9.66
Edison International	0.90	0.61	0.75	8.86	4.60	11.25	11.80	11.52 (4)
Entergy Corporation	0.80	0.56	0.68	8.86	4.60	10.62	11.33	10.98
Evergy, Inc.	0.75	0.50	0.62	8.86	4.60	10.09	10.93	10.51
FirstEnergy Corporation	0.75	0.46	0.61	8.86	4.60	10.00	10.87	10.44
IDACORP, Inc.	0.70	0.45	0.57	8.86	4.60	9.65	10.60	10.13
OGE Energy Corporation	0.85	0.54	0.70	8.86	4.60	10.80	11.47	11.13
Pinnacle West Capital Corporation	0.75	0.45	0.60	8.86	4.60	9.92	10.80	10.36
Portland General Electric Company	0.75	0.47	0.61	8.86	4.60	10.00	10.87	10.44
Southern Company	0.75	0.39	0.57	8.86	4.60	9.65	10.60	10.13
Xcel Energy, Inc.	0.70	0.44	0.57	8.86	4.60	9.65	10.60	10.13
Mean			0.62			10.05 %	10.90 %	10.40 %
Median			0.61			10.00 %	10.87 %	10.44 %
Average of Mean and Median			0.62			10.03 %	10.89 %	10.42 %

Notes on page 38 of this Schedule.

Valley Energy, Inc. / Citizens' Electric Company of Lewisburg, PA / Wellsboro Electric Company
Notes to Accompany the Application of the CAPM and ECAPM

Notes:

(1) The market risk premium (MRP) is derived by using five different measures from four sources: Kroll, Value Line, Bloomberg, and S&P Capital IQ as illustrated below:

Measure 1: Kroll Arithmetic Mean MRP (1926-2024)

Arithmetic Mean Monthly Returns for Large Stocks 1926-2024:	12.29	%
Arithmetic Mean Income Returns on Long-Term Government Bonds:	4.99	
MRP based on Kroll Historical Data:	7.31	%

Measure 2: Application of a Regression Analysis to Kroll Historical Data

(1926-2024)	7.88	%

Measure 3: Application of the PRPM to Kroll Historical Data

(January 1926 - June 2025)	9.03	%

Measure 4: Value Line Projected MRP (Thirteen weeks ending July 18, 2025)

Total projected return on the market 3-5 years hence*:	13.13	%
Risk-Free Rate (see note 2):	4.60	
MRP based on Value Line Summary & Index:	8.53	%

*Forcasted 3-5 year capital appreciation plus expected dividend yield

Measure 5: Bloomberg, Value Line, and S&P Capital IQ Projected Return on the Market based on the S&P 500

Total return on the Market based on the S&P 500:	16.15	%
Risk-Free Rate (see note 2):	4.60	
MRP based on Bloomberg, Value Line, and S&P Capital IQ data	11.55	%

Average of all MRP Measures:	8.86	%

(2) For reasons explained in the Direct Testimony, the appropriate risk-free rate for cost of capital purposes is the average forecast of 30 year Treasury Bonds per the consensus of nearly 50 economists reported in Blue Chip Financial Forecasts. (See pages 32 and 33 of this Schedule.) The projection of the risk-free rate is illustrated below:

Third Quarter 2025	4.80	%
Fourth Quarter 2025	4.70	
First Quarter 2026	4.70	
Second Quarter 2026	4.70	
Third Quarter 2026	4.60	
Fourth Quarter 2026	4.60	
2027-2031	4.40	
2032-2036	4.30	
	4.60	%

(3) Average of Column 6 and Column 7.

(4) Results were excluded from the final average and median as they were more than two standard deviations from the proxy group's mean.

Sources of Information:
Value Line Summary and Index
Blue Chip Financial Forecasts, June 2, 2025 and July 1, 2025
Kroll Cost of Capital Navigator
S&P Capital IQ
Bloomberg Professional Services

Valley Energy, Inc. / Citizens' Electric Company of Lewisburg, PA / Wellsboro Electric Company
Basis of Selection of the Group of Non-Price Regulated Companies
Comparable in Total Risk to the Proxy Group of Eight Natural Gas Distribution Companies

The criteria for selection of the proxy group of non-price regulated companies comparable in total risk to the proxy group of eight natural gas distribution companies was that the non-price regulated companies be domestic and reported in Value Line Investment Survey (Standard Edition).

The proxy group of non-price regulated companies was selected based on the unadjusted beta range of 0.45 - 0.79 and residual standard error of the regression range of 2.6575 - 3.1695 of the proxy group of eight natural gas distribution companies.

These ranges are based upon plus or minus two standard deviations of the unadjusted beta and standard error of the regression. Plus or minus three standard deviations captures 95.50% of the distribution of unadjusted betas and residual standard errors of the regression.

The standard deviation of the proxy group of eight natural gas distribution companies' residual standard error of the regression is 0.1280. The standard deviation of the standard error of the regression is calculated as follows:

$$\text{Standard Deviation of the Std. Err. of the Regr.} = \frac{\text{Standard Error of the Regression}}{\sqrt{2N}}$$

where: N = number of observations. Since Value Line betas are derived from weekly price change observations over a period of five years, N = 259

$$\text{Thus,} \quad 0.128 = \frac{2.9135}{\sqrt{518}} = \frac{2.9135}{22.7596}$$

Source of Information: Value Line Proprietary Database, June 2025.
Value Line Investment Survey (Standard Edition).

Valley Energy, Inc. / Citizens' Electric Company of Lewisburg, PA / Wellsboro Electric Company
Basis of Selection of the Group of Non-Price Regulated Companies
Comparable in Total Risk to the Proxy Group of Fourteen Electric Companies

The criteria for selection of the proxy group of non-price regulated companies comparable in total risk to the proxy group of fourteen electric companies was that the non-price regulated companies be domestic and reported in Value Line Investment Survey (Standard Edition).

The proxy group of non-price regulated companies was selected based on the unadjusted beta range of 0.44 - 0.74 and residual standard error of the regression range of 2.4553 - 2.9285 of the proxy group of fourteen electric companies.

These ranges are based upon plus or minus two standard deviations of the unadjusted beta and standard error of the regression. Plus or minus three standard deviations captures 95.50% of the distribution of unadjusted betas and residual standard errors of the regression.

The standard deviation of the proxy group of fourteen electric companies' residual standard error of the regression is 0.1183. The standard deviation of the standard error of the regression is calculated as follows:

$$\text{Standard Deviation of the Std. Err. of the Regr.} = \frac{\text{Standard Error of the Regression}}{\sqrt{2N}}$$

where: N = number of observations. Since Value Line betas are derived from weekly price change observations over a period of five years, N = 259

$$\text{Thus,} \quad 0.1183 = \frac{2.6919}{\sqrt{518}} = \frac{2.6919}{22.7596}$$

Source of Information: Value Line Proprietary Database, June 2025.
Value Line Investment Survey (Standard Edition).

Valley Energy, Inc. / Citizens' Electric Company of Lewisburg, PA / Wellsboro Electric Company
Basis of Selection of Comparable Risk
Domestic Non-Price Regulated Companies

Proxy Group of Eight Natural Gas Distribution Companies	[1] Value Line Adjusted Beta	[2] Unadjusted Beta	[3] Residual Standard Error of the Regression	[4] Standard Deviation of Beta
Atmos Energy Corporation	0.75	0.59	2.4122	0.0683
Chesapeake Utilities Corporation	0.70	0.54	3.1342	0.0888
New Jersey Resources Corporation	0.80	0.67	2.9138	0.0825
NiSource Inc.	0.85	0.70	2.4888	0.0705
Northwest Natural Holding Company	0.75	0.60	3.0651	0.0868
ONE Gas, Inc.	0.75	0.60	3.1352	0.0888
Southwest Gas Holdings, Inc.	0.80	0.62	3.3016	0.0935
Spire Inc.	0.75	0.61	2.8570	0.0809
Average	0.77	0.62	2.9135	0.0825
Beta Range (+/- 2 std. Devs. of Beta)	0.45	0.79		
2 std. Devs. of Beta	0.17			
Residual Std. Err. Range (+/- 2 std. Devs. of the Residual Std. Err.)	2.6575	3.1695		
Std. dev. of the Res. Std. Err.	0.1280			
2 std. devs. of the Res. Std. Err.	0.2560			

Proxy Group of Fourteen Electric Companies	[1] Value Line Adjusted Beta	[2] Unadjusted Beta	[3] Residual Standard Error of the Regression	[4] Standard Deviation of Beta
Alliant Energy Corporation	0.80	0.65	2.4909	0.0705
American Electric Power Corporation	0.70	0.47	2.6248	0.0743
Ameren Corporation	0.80	0.62	2.4689	0.0699
Duke Energy Corporation	0.65	0.42	2.3199	0.0657
Edison International	0.85	0.77	3.4576	0.0979
Entergy Corporation	0.80	0.64	2.6699	0.0756
Evergy, Inc.	0.75	0.58	2.6607	0.0753
FirstEnergy Corporation	0.75	0.56	3.4879	0.0988
IDACORP, Inc.	0.70	0.48	2.5048	0.0709
OGE Energy Corporation	0.85	0.73	2.4433	0.0692
Pinnacle West Capital Corporation	0.80	0.62	2.7730	0.0785
Portland General Electric Company	0.75	0.62	2.7838	0.0788
Southern Company	0.70	0.50	2.3719	0.0672
Xcel Energy, Inc.	0.75	0.54	2.6288	0.0744
Average	0.76	0.59	2.6919	0.0762
Beta Range (+/- 2 std. Devs. of Beta)	0.44	0.74		
2 std. Devs. of Beta	0.15			
Residual Std. Err. Range (+/- 2 std. Devs. of the Residual Std. Err.)	2.4553	2.9285		
Std. dev. of the Res. Std. Err.	0.1183			
2 std. devs. of the Res. Std. Err.	0.2366			

Source of Information: Value Line Proprietary Database, June 2025.

Valley Energy, Inc. / Citizens' Electric Company of Lewisburg, PA / Wellsboro Electric Company
Proxy Group of Non-Price Regulated Companies
Comparable in Total Risk to the
Proxy Group of Eight Natural Gas Distribution Companies and Proxy Group of Fourteen Electric Companies

	[1]	[2]	[3]	[4]
Proxy Group of Twenty-Eight Non-Price Regulated Companies	Value Line Adjusted Beta	Unadjusted Beta	Residual Standard Error of the Regression	Standard Deviation of Beta
AbbVie Inc.	0.70	0.48	2.9984	0.0849
Amgen	0.70	0.52	2.9231	0.0828
AutoZone Inc.	0.75	0.61	2.9796	0.0844
Becton, Dickinson	0.75	0.55	2.9156	0.0826
Bristol-Myers Squibb	0.70	0.53	3.0636	0.0868
Casella Waste Sys.	0.85	0.74	2.8152	0.0797
Cencora	0.65	0.47	2.7020	0.0765
Chemed Corp.	0.70	0.50	2.9028	0.0822
Constellation Brands	0.80	0.63	2.9286	0.0829
Costco Wholesale	0.80	0.66	2.7408	0.0776
Gilead Sciences	0.75	0.56	2.9551	0.0837
Henry (Jack) & Assoc	0.80	0.68	2.9558	0.0837
Int'l Business Mach.	0.80	0.67	2.9091	0.0824
L3Harris Technologie	0.80	0.69	3.0374	0.0860
Labcorp Holdings	0.75	0.62	2.9139	0.0825
McCormick & Co.	0.70	0.50	3.0004	0.0850
McKesson Corp.	0.70	0.51	2.8601	0.0810
Monster Beverage	0.75	0.55	2.7035	0.0766
NewMarket Corp.	0.80	0.62	2.9198	0.0827
O'Reilly Automotive	0.80	0.62	2.7740	0.0786
Philip Morris Int'l	0.80	0.64	2.8039	0.0794
Prestige Consumer	0.75	0.62	3.0893	0.0875
Progressive Corp.	0.80	0.63	3.0075	0.0852
RLI Corp.	0.85	0.77	2.8552	0.0809
VeriSign Inc.	0.90	0.78	2.8545	0.0808
Walmart Inc.	0.75	0.56	2.7251	0.0772
Wendy's Company	0.85	0.72	2.9914	0.0847
Werner Enterprises	0.85	0.76	3.0727	0.0870
Average	0.77	0.61	2.9071	0.0823
Proxy Group of Eight Natural Gas Distribution Companies	0.77	0.62	2.9135	0.0825

Source of Information: Value Line Proprietary Database, June 2025.

Valley Energy, Inc. / Citizens' Electric Company of Lewisburg, PA / Wellsboro Electric Company
Proxy Group of Non-Price Regulated Companies
Comparable in Total Risk to the
Proxy Group of Eight Natural Gas Distribution Companies and Proxy Group of Fourteen Electric Companies

	[1]	[2]	[3]	[4]
Proxy Group of Sixteen Non-Price Regulated Companies	Value Line Adjusted Beta	Unadjusted Beta	Residual Standard Error of the Regression	Standard Deviation of Beta
Abbott Labs.	0.75	0.58	2.6340	0.0746
Altria Group	0.70	0.53	2.6379	0.0747
Amgen	0.70	0.52	2.9231	0.0828
Becton, Dickinson	0.75	0.55	2.9156	0.0826
Cencora	0.65	0.47	2.7020	0.0765
Chemed Corp.	0.70	0.50	2.9028	0.0822
Costco Wholesale	0.80	0.66	2.7408	0.0776
Ingredion Inc.	0.85	0.72	2.5471	0.0721
Int'l Business Mach.	0.80	0.67	2.9091	0.0824
Labcorp Holdings	0.75	0.62	2.9139	0.0825
McKesson Corp.	0.70	0.51	2.8601	0.0810
Monster Beverage	0.75	0.55	2.7035	0.0766
NewMarket Corp.	0.80	0.62	2.9198	0.0827
O'Reilly Automotive	0.80	0.62	2.7740	0.0786
Philip Morris Int'l	0.80	0.64	2.8039	0.0794
Walmart Inc.	0.75	0.56	2.7251	0.0772
Average	0.75	0.58	2.7883	0.0790
Proxy Group of Fourteen Electric Companies	0.76	0.59	2.6919	0.0762

Source of Information: Value Line Proprietary Database, June 2025.

Valley Energy, Inc. / Citizens' Electric Company of Lewisburg, PA / Wellsboro Electric Company
Summary of Cost of Equity Models Applied to
Proxy Group of Non-Price Regulated Companies
Comparable in Total Risk to the
Proxy Group of Eight Natural Gas Distribution Companies and Proxy Group of Fourteen Electric Companies

Principal Methods	Proxy Group of Twenty-Eight Non-Price Regulated Companies	Proxy Group of Sixteen Non-Price Regulated Companies
Discounted Cash Flow Model (DCF) (1)	10.57 %	10.19 %
Risk Premium Model (RPM) (2)	11.27	11.11
Capital Asset Pricing Model (CAPM) (3)	10.87	10.81
Mean	10.90 %	10.70 %
Median	10.87 %	10.81 %
Average of Mean and Median	10.89 %	10.76 %

Notes:
(1) From pages 45-46 of this Schedule
(2) From page 47 of this Schedule
(3) From pages 51-52 of this Schedule

Valley Energy, Inc. / Citizens' Electric Company of Lewisburg, PA / Wellsboro Electric Company
DCF Results for the Proxy Group of Non-Price-Regulated Companies Comparable in Total Risk to the
Proxy Group of Eight Natural Gas Distribution Companies

	[1]	[2]	[3]	[4]	[5]	[6]	[7]
Proxy Group of Twenty-Eight Non-Price Regulated Companies	Average Dividend Yield	Value Line Projected Five Year Growth in EPS	Zack's Five Year Projected Growth Rate in EPS	S&P Capital IQ Projected Five Year Growth in EPS	Average Projected Five Year Growth Rate in EPS	Adjusted Dividend Yield	Indicated Common Equity Cost Rate (1)
AbbVie Inc.	3.50 %	7.00 %	12.60 %	13.66 %	11.09 %	3.69 %	14.78 %
Amgen	3.35	5.50	5.30	5.26	5.35	3.44	8.79
AutoZone Inc.	-	7.50	11.40	10.85	9.92	-	NA
Becton, Dickinson	2.36	7.50	9.30	9.45	8.75	2.46	11.21
Bristol-Myers Squibb	5.19	30.00	3.00	NMF	16.50	5.62	22.12 (2)
Casella Waste Sys.	-	6.50	25.80	(3.06)	16.15	-	NA
Cencora	0.75	6.50	12.80	12.66	10.65	0.79	11.44
Chemed Corp.	0.37	8.00	9.80	9.78	9.19	0.39	9.58
Constellation Brands	2.31	6.50	1.30	4.32	4.04	2.36	6.40
Costco Wholesale	0.52	10.00	9.00	9.11	9.37	0.54	9.91
Gilead Sciences	2.94	16.00	19.50	24.79	20.10	3.24	23.34 (2)
Henry (Jack) & Assoc	1.30	5.50	NA	NA	5.50	1.34	6.84
Int'l Business Mach.	2.50	3.00	4.30	6.90	4.73	2.56	7.29
L3Harris Technologie	2.00	14.50	12.30	12.25	13.02	2.13	15.15
Labcorp Holdings	1.15	6.00	9.80	9.55	8.45	1.20	9.65
McCormick & Co.	2.43	6.00	6.80	6.17	6.32	2.51	8.83
McKesson Corp.	0.40	10.00	13.50	10.84	11.45	0.42	11.87
Monster Beverage	-	12.00	15.00	13.52	13.51	-	NA
NewMarket Corp.	1.67	5.50	NA	NA	5.50	1.72	7.22
O'Reilly Automotive	-	10.50	12.60	11.91	11.67	-	NA
Philip Morris Int'l	3.05	5.00	9.30	11.49	8.60	3.18	11.78
Prestige Consumer	-	6.50	7.00	7.67	7.06	-	NA
Progressive Corp.	0.15	16.50	9.50	13.20	13.07	0.16	13.23
RLI Corp.	0.87	13.50	NA	NA	13.50	0.93	14.43
VeriSign Inc.	1.10	10.00	NA	NA	10.00	1.16	11.16
Walmart Inc.	0.97	10.00	8.00	7.92	8.64	1.01	9.65
Wendy's Company	4.78	11.00	6.70	5.72	7.81	4.97	12.78
Werner Enterprises	-	NA	NMF	NMF	NA	NA	NA
						Mean	10.60 %
						Median	10.54 %
						Average of Mean and Median	10.57 %

NA = Not Available
NMF = Not Meaningful Figure

Notes:

(1) The application of the DCF model to the domestic, non-price regulated comparable risk companies is identical to the application of the DCF to the Utility Proxy Groups. The dividend yield is derived by using the 60 day average price and the spot indicated dividend as of 7/18/2025. The dividend yield is then adjusted by 1/2 the average projected growth rate in EPS, which is calculated by averaging the 5 year projected growth in EPS provided by Value Line, www.zacks.com, and S&P Capital IQ (excluding any negative growth rates) and then adding that growth rate to the adjusted dividend yield.

(2) Results were excluded from the final average and median as they were more than two standard deviations from the proxy group's mean.

Source of Information:

Value Line Investment Survey.
www.zacks.com, Downloaded on 7/18/2025
S&P Capital IQ

Valley Energy, Inc. / Citizens' Electric Company of Lewisburg, PA / Wellsboro Electric Company
DCF Results for the Proxy Group of Non-Price-Regulated Companies Comparable in Total Risk to the
Proxy Group of Fourteen Electric Companies

	[1]	[2]	[3]	[4]	[5]	[6]	[7]
Proxy Group of Sixteen Non-Price Regulated Companies	Average Dividend Yield	Value Line Projected Five Year Growth in EPS	Zack's Five Year Projected Growth Rate in EPS	S&P Capital IQ Projected Five Year Growth in EPS	Average Projected Five Year Growth Rate in EPS	Adjusted Dividend Yield	Indicated Common Equity Cost Rate (1)
Abbott Labs.	1.78 %	6.00 %	10.20 %	9.59 %	8.60 %	1.86 %	10.46 %
Altria Group	6.90	6.00	3.20	3.85	4.35	7.05	11.40
Amgen	3.35	5.50	5.30	5.26	5.35	3.44	8.79
Becton, Dickinson	2.36	7.50	9.30	9.45	8.75	2.46	11.21
Cencora	0.75	6.50	12.80	12.66	10.65	0.79	11.44
Chemed Corp.	0.37	8.00	9.80	9.78	9.19	0.39	9.58
Costco Wholesale	0.52	10.00	9.00	9.11	9.37	0.54	9.91
Ingredion Inc.	2.35	7.50	11.00	11.00	9.83	2.47	12.30
Int'l Business Mach.	2.50	3.00	4.30	6.90	4.73	2.56	7.29
Labcorp Holdings	1.15	6.00	9.80	9.55	8.45	1.20	9.65
McKesson Corp.	0.40	10.00	13.50	10.84	11.45	0.42	11.87
Monster Beverage	-	12.00	15.00	13.52	13.51	-	NA
NewMarket Corp.	1.67	5.50	NA	NA	5.50	1.72	7.22
O'Reilly Automotive	-	10.50	12.60	11.91	11.67	-	NA
Philip Morris Int'l	3.05	5.00	9.30	11.49	8.60	3.18	11.78
Walmart Inc.	0.97	10.00	8.00	7.92	8.64	1.01	9.65
	NA = Not Available					Mean	10.18 %
						Median	10.19 %
					Average of Mean and Median		10.19 %

Notes:

(1) The application of the DCF model to the domestic, non-price regulated comparable risk companies is identical to the application of the DCF to the Utility Proxy Groups. The dividend yield is derived by using the 60 day average price and the spot indicated dividend as of 7/18/2025. The dividend yield is then adjusted by 1/2 the average projected growth rate in EPS, which is calculated by averaging the 5 year projected growth in EPS provided by Value Line, www.zacks.com, and S&P Capital IQ (excluding any negative growth rates) and then adding that growth rate to the adjusted dividend yield.

Source of Information:

Value Line Investment Survey.
www.zacks.com, Downloaded on 7/18/2025
S&P Capital IQ

Valley Energy, Inc. / Citizens' Electric Company of Lewisburg, PA / Wellsboro Electric Company
Indicated Common Equity Cost Rate
Through Use of a Risk Premium Model
Using an Adjusted Total Market Approach

Line No.		Proxy Group of Twenty-Eight Non-Price Regulated Companies	Proxy Group of Sixteen Non-Price Regulated Companies
1.	Prospective Yield on Baa2 Rated Corporate Bonds (1)	6.05 %	6.05
2.	Adjustment to Reflect Bond rating Difference of Non-Price Regulated Companies (2)	(0.21)	(0.21)
3.	Adjusted Bond Yield	5.84	5.84
4.	Equity Risk Premium (3)	5.43	5.27
5.	Risk Premium Derived Common Equity Cost Rate	11.27 %	11.11

Notes: (1) Average forecast of Baa corporate bonds based upon the consensus of nearly 50 economists reported in Blue Chip Financial Forecasts dated June 2, 2025 and July 1, 2025 (see pages 32 and 33 of this Schedule). The estimates are detailed below.

Third Quarter 2025	6.30 %
Fourth Quarter 2025	6.20
First Quarter 2026	6.10
Second Quarter 2026	6.00
Third Quarter 2026	5.90
Fourth Quarter 2026	5.90
2027-2031	6.00
2032-2036	6.00
Average	6.05 %

(2) The average yield spread of Baa2 rated corporate bonds over A2 corporate bonds for the three months ending June 2025. To reflect the A3 average rating of both the Proxy Group of Twenty-Eight Non-Price Regulated Companies and the Proxy Group of Sixteen Non-Price Regulated Companies, the yield on the Baa corporate bonds must be adjusted by two-thirds of the spread between A2 and Baa2 corporate bond yields, as shown below.

	A2 Corp. Bond Yield	Baa2 Corp. Bond Yield	Spread
Jun-25	5.86 %	6.15 %	0.29 %
May-25	5.97	6.29	0.32
Apr-25	5.85	6.18	0.33
		Average yield spread	0.31
		2/3 of spread	0.21

(3) From page 50 of this Schedule.

Valley Energy, Inc. / Citizens' Electric Company of Lewisburg, PA / Wellsboro Electric Company
Comparison of Long-Term Issuer Ratings for the
Proxy Group of Twenty-Eight Non-Price Regulated Companies

Proxy Group of Twenty-Eight Non-Price Regulated Companies	Moody's Long-Term Issuer Rating July 2025		Standard & Poor's Long-Term Issuer Rating July 2025	
	Long-Term Issuer Rating	Numerical Weighting (1)	Long-Term Issuer Rating	Numerical Weighting (1)
AbbVie Inc.	A3	7.0	A-	7.0
Amgen	Baa1	8.0	BBB+	8.0
AutoZone Inc.	Baa1	8.0	BBB	9.0
Becton, Dickinson	Baa2	9.0	BBB	9.0
Bristol-Myers Squibb	A2	6.0	A	6.0
Casella Waste Sys.	NA	--	BB	12.0
Cencora	Baa2	9.0	BBB+	8.0
Chemed Corp.	WR	--	NR	--
Constellation Brands	Baa2	9.0	BBB	9.0
Costco Wholesale	Aa3	4.0	AA	3.0
Gilead Sciences	A3	7.0	A-	7.0
Henry (Jack) & Assoc	NA	--	NA	--
Int'l Business Mach.	A3	7.0	A-	7.0
L3Harris Technologie	Baa2	9.0	BBB	9.0
Labcorp Holdings	NA	--	BBB	9.0
McCormick & Co.	Baa2	9.0	BBB	9.0
McKesson Corp.	A3	7.0	BBB+	8.0
Monster Beverage	NA	--	NA	--
NewMarket Corp.	Baa2	9.0	BBB+	8.0
O'Reilly Automotive	Baa1	8.0	BBB	9.0
Philip Morris Int'l	A2	6.0	A-	7.0
Prestige Consumer	NA	--	BB	12.0
Progressive Corp.	A2	6.0	A	6.0
RLI Corp.	WR	--	BBB	9.0
VeriSign Inc.	Baa3	10.0	BBB	9.0
Walmart Inc.	Aa2	3.0	AA	3.0
Wendy's Company	NA	--	B+	14.0
Werner Enterprises	NA	--	NA	--
Natural Gas CEM Proxy Group Average	A3	7.4	BBB+	8.2

Notes:
(1) From page 29 of this Schedule.

Source of Information:
Bloomberg Professional Services.

Valley Energy, Inc. / Citizens' Electric Company of Lewisburg, PA / Wellsboro Electric Company
Comparison of Long-Term Issuer Ratings for the
Proxy Group of Sixteen Non-Price Regulated Companies

Proxy Group of Sixteen Non-Price Regulated Companies	Moody's Long-Term Issuer Rating July 2025		Standard & Poor's Long-Term Issuer Rating July 2025	
	Long-Term Issuer Rating	Numerical Weighting (1)	Long-Term Issuer Rating	Numerical Weighting (1)
Abbott Labs.	Aa3	4.0	AA-	4.0
Altria Group	A3	7.0	BBB+	8.0
Amgen	Baa1	8.0	BBB+	8.0
Becton, Dickinson	Baa2	9.0	BBB	9.0
Cencora	Baa2	9.0	BBB+	8.0
Chemed Corp.	WR	--	NR	--
Costco Wholesale	Aa3	4.0	AA	3.0
Ingredion Inc.	Baa1	8.0	BBB	9.0
Int'l Business Mach.	A3	7.0	A-	7.0
Labcorp Holdings	NA	--	BBB	9.0
McKesson Corp.	A3	7.0	BBB+	8.0
Monster Beverage	NA	--	NA	--
NewMarket Corp.	Baa2	9.0	BBB+	8.0
O'Reilly Automotive	Baa1	8.0	BBB	9.0
Philip Morris Int'l	A2	6.0	A-	7.0
Walmart Inc.	Aa2	3.0	AA	3.0
Electric CEM Proxy Group Average	A3	6.8	A-	7.1

Notes:
(1) From page 29 of this Schedule.

Source of Information:
Bloomberg Professional Services.

Valley Energy, Inc. / Citizens' Electric Company of Lewisburg, PA / Wellsboro Electric Company
Derivation of Equity Risk Premium Based on the Total Market Approach
Using the Beta for
Non-Price Regulated Companies of Comparable risk to the
Proxy Group of Eight Natural Gas Distribution Companies and Proxy Group of Fourteen Electric Companies

Line No.	Equity Risk Premium Measure	Proxy Group of Twenty-Eight Non-Price Regulated Companies	Proxy Group of Sixteen Non-Price Regulated Companies
1.	Kroll Equity Risk Premium (1)	6.10 %	6.10 %
2.	Regression on Kroll Risk Premium Data (2)	6.97	6.97
3.	Kroll Equity Risk Premium based on PRPM (3)	8.08	8.08
4.	Equity Risk Premium Based on Value Line Summary and Index (4)	7.90	7.90
5.	Equity Risk Premium Based on Bloomberg, Value Line, and S&P Global Market Intelligence S&P 500 Companies (5)	10.92	10.92
6.	Conclusion of Equity Risk Premium	7.99 %	7.99 %
7.	Adjusted Beta (6)	0.68	0.66
8.	Forecasted Equity Risk Premium	5.43 %	5.27 %

Notes:
(1) From note 1 of page 31 of this Schedule.
(2) From note 2 of page 31 of this Schedule.
(3) From note 3 of page 31 of this Schedule.
(4) From note 4 of page 31 of this Schedule.
(5) From note 5 of page 31 of this Schedule.
(6) Average of mean and median beta from pages 51-52 of this Schedule.

Sources of Information:
Kroll Cost of Capital Navigator
Value Line Summary and Index
Blue Chip Financial Forecasts, June 2, 2025 and July 1, 2025
Bloomberg Professional Services

Valley Energy, Inc. / Citizens' Electric Company of Lewisburg, PA / Wellsboro Electric Company
Traditional CAPM and ECAPM Results for the Proxy Groups of Non-Price-Regulated Companies Comparable in Total Risk to th
Proxy Group of Eight Natural Gas Distribution Companies and Proxy Group of Fourteen Electric Companie

Proxy Group of Twenty-Eight Non-Price Regulated Companie

	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]
Proxy Group of Twenty-Eight Non-Price Regulated Companies	Value Line Adjusted Beta	Bloomberg Beta	Average Beta	Market Risk Premium (1)	Risk-Free Rate (2)	Traditional CAPM Cost Rate	ECAPM Cost Rate	Indicated Common Equity Cost Rate (3)
AbbVie Inc.	0.70	0.55	0.63	8.86 %	4.60 %	10.18 %	11.00 %	10.59 %
Amgen	0.70	0.56	0.63	8.86	4.60	10.18	11.00	10.59
AutoZone Inc.	0.75	0.57	0.66	8.86	4.60	10.45	11.20	10.82
Becton, Dickinson	0.75	0.56	0.65	8.86	4.60	10.36	11.13	10.75
Bristol-Myers Squibb	0.70	0.45	0.57	8.86	4.60	9.65	10.60	10.13
Casella Waste Sys.	0.85	0.62	0.74	8.86	4.60	11.16	11.73	11.44
Cencora	0.70	0.43	0.56	8.86	4.60	9.56	10.54	10.05
Chemed Corp.	0.70	0.43	0.57	8.86	4.60	9.65	10.60	10.13
Constellation Brands	0.75	0.63	0.69	8.86	4.60	10.71	11.40	11.06
Costco Wholesale	0.80	0.76	0.78	8.86	4.60	11.51	12.00	11.75
Gilead Sciences	0.75	0.57	0.66	8.86	4.60	10.45	11.20	10.82
Henry (Jack) & Assoc	0.80	0.53	0.66	8.86	4.60	10.45	11.20	10.82
Int'l Business Mach.	0.85	0.74	0.79	8.86	4.60	11.60	12.06	11.83
L3Harris Technologie	0.85	0.73	0.79	8.86	4.60	11.60	12.06	11.83
Labcorp Holdings	0.75	0.60	0.67	8.86	4.60	10.54	11.27	10.90
McCormick & Co.	0.70	0.49	0.60	8.86	4.60	9.92	10.80	10.36
McKesson Corp.	0.75	0.50	0.63	8.86	4.60	10.18	11.00	10.59
Monster Beverage	0.75	0.58	0.66	8.86	4.60	10.45	11.20	10.82
NewMarket Corp.	0.75	0.70	0.72	8.86	4.60	10.98	11.60	11.29
O'Reilly Automotive	0.75	0.49	0.62	8.86	4.60	10.09	10.94	10.51
Philip Morris Int'l	0.80	0.42	0.61	8.86	4.60	10.00	10.87	10.44
Prestige Consumer	0.80	0.56	0.68	8.86	4.60	10.62	11.33	10.98
Progressive Corp.	0.75	0.62	0.69	8.86	4.60	10.71	11.40	11.06
RLI Corp.	0.85	0.51	0.68	8.86	4.60	10.62	11.33	10.98
VeriSign Inc.	0.90	0.65	0.78	8.86	4.60	11.51	12.00	11.75
Walmart Inc.	0.75	0.78	0.76	8.86	4.60	11.33	11.87	11.60
Wendy's Company	0.85	0.50	0.68	8.86	4.60	10.62	11.33	10.98
Werner Enterprises	0.80	0.86	0.83	8.86	4.60	11.95	12.33	12.14 (4)
		Mean	0.68			10.61 %	11.32 %	10.92 %
		Median	0.67			10.49 %	11.23 %	10.82 %
		Average of Mean and Mediar	0.68			10.55 %	11.28 %	10.87 %

Notes on page 52 of this Schedule

Valley Energy, Inc. / Citizens' Electric Company of Lewisburg, PA / Wellsboro Electric Company
Traditional CAPM and ECAPM Results for the Proxy Groups of Non-Price-Regulated Companies Comparable in Total Risk to th
Proxy Group of Eight Natural Gas Distribution Companies and Proxy Group of Fourteen Electric Companie

Proxy Group of Sixteen Non-Price Regulated Companie

Proxy Group of Sixteen Non-Price Regulated Companies	[1] Value Line Adjusted Beta	[2] Bloomberg Beta	[3] Average Beta	[4] Market Risk Premium (1)	[5] Risk-Free Rate (2)	[6] Traditional CAPM Cost Rate	[7] ECAPM Cost Rate	[8] Indicated Common Equity Cost Rate (3)
Abbott Labs.	0.75	0.56	0.66	8.86 %	4.60 %	10.45 %	11.20 %	10.82 %
Altria Group	0.70	0.43	0.56	8.86	4.60	9.56	10.54	10.05
Amgen	0.70	0.56	0.63	8.86	4.60	10.18	11.00	10.59
Becton, Dickinson	0.75	0.56	0.65	8.86	4.60	10.36	11.13	10.75
Cencora	0.70	0.43	0.56	8.86	4.60	9.56	10.54	10.05
Chemed Corp.	0.70	0.43	0.57	8.86	4.60	9.65	10.60	10.13
Costco Wholesale	0.80	0.76	0.78	8.86	4.60	11.51	12.00	11.75
Ingredion Inc.	0.85	0.58	0.71	8.86	4.60	10.89	11.53	11.21
Int'l Business Mach.	0.85	0.74	0.79	8.86	4.60	11.60	12.06	11.83
Labcorp Holdings	0.75	0.60	0.67	8.86	4.60	10.54	11.27	10.90
McKesson Corp.	0.75	0.50	0.63	8.86	4.60	10.18	11.00	10.59
Monster Beverage	0.75	0.58	0.66	8.86	4.60	10.45	11.20	10.82
NewMarket Corp.	0.75	0.70	0.72	8.86	4.60	10.98	11.60	11.29
O'Reilly Automotive	0.75	0.49	0.62	8.86	4.60	10.09	10.94	10.51
Philip Morris Int'l	0.80	0.42	0.61	8.86	4.60	10.00	10.87	10.44
Walmart Inc.	0.75	0.78	0.76	8.86	4.60	11.33	11.87	11.60
		Mean	0.66			10.46 %	11.21 %	10.83 %
		Median	0.66			10.40 %	11.17 %	10.79 %
	Average of Mean and Mediar		0.66			10.43 %	11.19 %	10.81 %

Notes:
(1) From note 1 of page 38 of this Schedule
(2) From note 2 of page 38 of this Schedule.
(3) Average of CAPM and ECAPM cost rates
(4) Results were excluded from the final average and median as they were more than two standard deviations from the proxy group's mean.

Valley Energy, Inc. / Citizens' Electric Company of Lewisburg, PA / Wellsboro Electric Company
Derivation of Investment Risk Adjustment Based upon
Ibbotson Associates' Size Premia for the Decile Portfolios of the NYSE/AMEX/NASDAQ

Line No.		[1] Market Capitalization on July 18, 2025 (1) (millions)		[2] Applicable Decile of the NYSE/AMEX/ NASDAQ (2)	[3] Applicable Size Premium (3)	[4] Spread from Applicable Size Premium (4)
1.	a. Valley Energy, Inc.	$ 20.621		10	4.47%	
	b. Citizens' Electric Company of Lewisburg, PA	$ 17.475		10	4.47%	
	c. Wellsboro Electric Company	$ 23.934		10	4.47%	
2.	a. Proxy Group of Eight Natural Gas Distribution Companies	$ 4,473.164	216.9 x	5	0.74%	3.73%
	b. Proxy Group of Fourteen Electric Companies	$ 21,596.069	1,235.8 x	2	0.33%	4.14%
	c. Proxy Group of Fourteen Electric Companies	$ 21,596.069	902.3 x	2	0.33%	4.14%
			[A]	[B]	[C]	[D]

	Decile	Market Capitalization of Smallest Company (millions)	Market Capitalization of Largest Company (millions)	Size Premium (Return in Excess of CAPM)*
Largest	1	$ 47,156.530	$ 3,522,211.140	-0.01%
	2	20,191.220	46,949.060	0.33%
	3	9,937.940	20,178.360	0.49%
	4	6,196.710	9,937.350	0.50%
	5	3,948.050	6,181.270	0.74%
	6	2,481.780	3,946.150	1.00%
	7	1,422.890	2,464.500	1.19%
	8	731.190	1,417.450	0.88%
	9	304.620	729.920	1.73%
Smallest	10	1.110	304.480	4.47%

*From 2025 Kroll Cost of Capital Navigator

Notes:

(1) From page 54 of this Exhibit.
(2) Gleaned from Columns [B] and [C] on the bottom of this page. The appropriate decile (Column [A]) corresponds to the market capitalization of the proxy group, which is found in Column [1].
(3) Corresponding risk premium to the decile is provided in Column [D] on the bottom of this page.
(4) Line No. 1 Column [3] – Line No. 2 Column [3]. For example, the 3.73% in Column [4], Line No. 2 is derived as follows 3.73% = 4.47% - 0.74%.

Valley Energy, Inc. / Citizens' Electric Company of Lewisburg, PA / Wellsboro Electric Company
Market Capitalization of Valley Energy, Inc. / Citizens' Electric Company of Lewisburg, PA / Wellsboro Electric Company and the
Proxy Group of Eight Natural Gas Distribution Companies and Proxy Group of Fourteen Electric Companies

Company	Exchange	[1] Common Stock Shares Outstanding at Fiscal Year End 2024 (millions)	[2] Book Value per Share at Fiscal Year End 2023 (1)	[3] Total Common Equity at Fiscal Year End 2024 (millions)	[4] Closing Stock Market Price on July 18, 2025	[5] Market-to-Book Ratio on July 18, 2025 (2)	[6] Market Capitalization on July 18, 2025 (3) (millions)
Valley Energy, Inc.		NA	NA	$ 11.462 (4)	NA		
Citizens' Electric Company of Lewisburg, PA		NA	NA	$ 9.022 (4)	NA		
Wellsboro Electric Company		NA	NA	$ 12.356 (4)	NA		
Based upon Proxy Group of Eight Natural Gas Distribution Companies						179.9 (5)	$ 20.621 (6)
Based upon Proxy Group of Fourteen Electric Companies						193.7 (5)	$ 17.475 (6)
Based upon Proxy Group of Fourteen Electric Companies						193.7 (5)	$ 23.934 (6)
Proxy Group of Eight Natural Gas Distribution Companies							
Atmos Energy Corporation	NYSE	155.26	$ 78.306	$ 12,157.67	$ 156.66	200.10 %	$ 24,322.851
Chesapeake Utilities Corporation	NYSE	22.90	60.71	1,390.20	122.11	201.10	2,796.20
New Jersey Resources Corporation	NYSE	99.46	22.12	2,200.44	45.73	206.70	4,548.37
NiSource Inc.	NYSE	469.82	18.48	8,684.20	40.90	221.30	19,215.74
Northwest Natural Holding Company	NYSE	40.22	34.44	1,385.37	41.53	120.60	1,670.43
ONE Gas, Inc.	NYSE	59.88	51.85	3,104.55	73.45	141.70	4,397.96
Southwest Gas Holdings, Inc.	NYSE	71.78	48.82	3,504.19	77.98	159.70	5,597.62
Spire Inc.	NYSE	57.75	55.98	3,232.70	75.32	134.60	4,349.71
Median		65.830	$ 50.333	$ 3,168.624	$ 74.385	179.9 %	$ 4,473.164
Proxy Group of Fourteen Electric Companies							
Alliant Energy Corporation	NASDAQ	256.69	$ 27.286	$ 7,004.00	$ 64.13	235.00 %	$ 16,461.544
American Electric Power Corporation	NYSE	532.91	50.56	26,943.80	107.40	212.40	57,234.29
Ameren Corporation	NASDAQ	269.90	44.88	12,114.00	98.70	219.90	26,639.13
Duke Energy Corporation	NYSE	776.00	63.34	49,154.00	118.42	187.00	91,893.92
Edison International	NYSE	384.78	36.18	13,920.00	51.14	141.40	19,677.89
Entergy Corporation	NYSE	429.58	35.11	15,083.91	86.40	246.10	37,115.75
Evergy, Inc.	NASDAQ	229.98	43.29	9,955.00	68.90	159.20	15,845.87
FirstEnergy Corporation	NYSE	576.61	21.60	12,455.00	40.78	188.80	23,514.25
IDACORP, Inc.	NASDAQ	53.96	61.73	3,330.95	120.18	194.70	6,485.15
OGE Energy Corporation	NYSE	200.80	23.11	4,640.90	44.54	192.70	8,943.63
Pinnacle West Capital Corporation	NYSE	119.14	56.69	6,754.31	92.51	163.20	11,021.99
Portland General Electric Company	NYSE	109.34	34.70	3,794.00	40.02	115.30	4,375.88
Southern Company	NYSE	1,100.00	30.19	33,208.00	94.10	311.70	103,510.00
Xcel Energy, Inc.	NYSE	574.37	33.99	19,522.00	70.38	207.10	40,423.85
Median		327.342	$ 35.645	$ 12,284.500	$ 78.390	193.7 %	$ 21,596.069

NA= Not Available

Notes:
(1) Column 3 / Column 1.
(2) Column 4 / Column 2.
(3) Column 1 * Column 4.
(4) Requested rate base multiplied by the requested common equity ratio
(5) The market-to-book ratio of Valley Energy, Inc. / Citizens' Electric Company of Lewisburg, PA / Wellsboro Electric Company on July 18, 2025 is assumed to be equal to the market-to-book ratio of Proxy Group of Eight Natural Gas Distribution Companies and Proxy Group of Fourteen Electric Companies on July 18, 2025 as appropriate.
(6) Column [3] multiplied by Column [5].

Source of Information: 2024 Annual Forms 10K
Bloomberg Professional

Valley Energy, Inc. / Citizens' Electric Company of Lewisburg, PA / Wellsboro Electric Company
R-Squareds of Betas of the I&E ROE Witnesses' Utility Proxy Group Companies

Mr. Patel's Gas Proxy Group

Company Name	Adjusted VL Beta	Correlation Coefficient	R-Squared
Atmos Energy Corporation	0.75	0.4746	0.2252
Chesapeake Utilities Corporation	0.70	0.3536	0.1250
New Jersey Resources Corporation	0.80	0.4507	0.2031
NiSource Inc.	0.85	0.5250	0.2756
Northwest Natural Holding Company	0.75	0.3952	0.1562
ONE Gas, Inc.	0.75	0.3900	0.1521
Spire Inc.	0.75	0.4241	0.1799
Average			0.1882

Mr. Keller's Electric Proxy Group (1)

Company Name	Adjusted VL Beta	Correlation Coefficient	R-Squared
Dominion Energy	0.75	0.4390	0.1927
Duke Energy	0.65	0.3738	0.1397
Consol. Edison	0.65	0.3593	0.1291
Eversource Energy	0.85	0.4717	0.2225
FirstEnergy Corp.	0.75	0.3320	0.1102
NextEra Energy	0.90	0.4571	0.2089
Public Serv. Enterpr	0.85	0.5465	0.2987
PPL Corp.	0.85	0.5522	0.3049
Average			0.2008

Notes:
(1) With the exception of Exelon Corporation, which does not have a beta.

Source of Information: Value Line Proprietary Database June 2025

Valley Energy, Inc. / Citizens' Electric Company of Lewisburg, PA / Wellsboro Electric Company
Standard Deviation of the I&E ROE Witnesses' DCF Results

Mr. Patel's Gas Proxy Group

Company Name	Yield	Growth	K
Atmos Energy Corporation	2.50 %	7.16 %	9.66 %
Chesapeake Utilities Corporation	2.32	8.44	10.76
New Jersey Resources Corporation	4.20	6.45	10.65
NiSource Inc.	3.27	8.41	11.68
Northwest Natural Holding Company	4.87	6.13	11.00
ONE Gas, Inc.	3.74	5.31	9.05
Spire Inc.	4.53	6.18	10.71
Standard Deviation			0.81 %

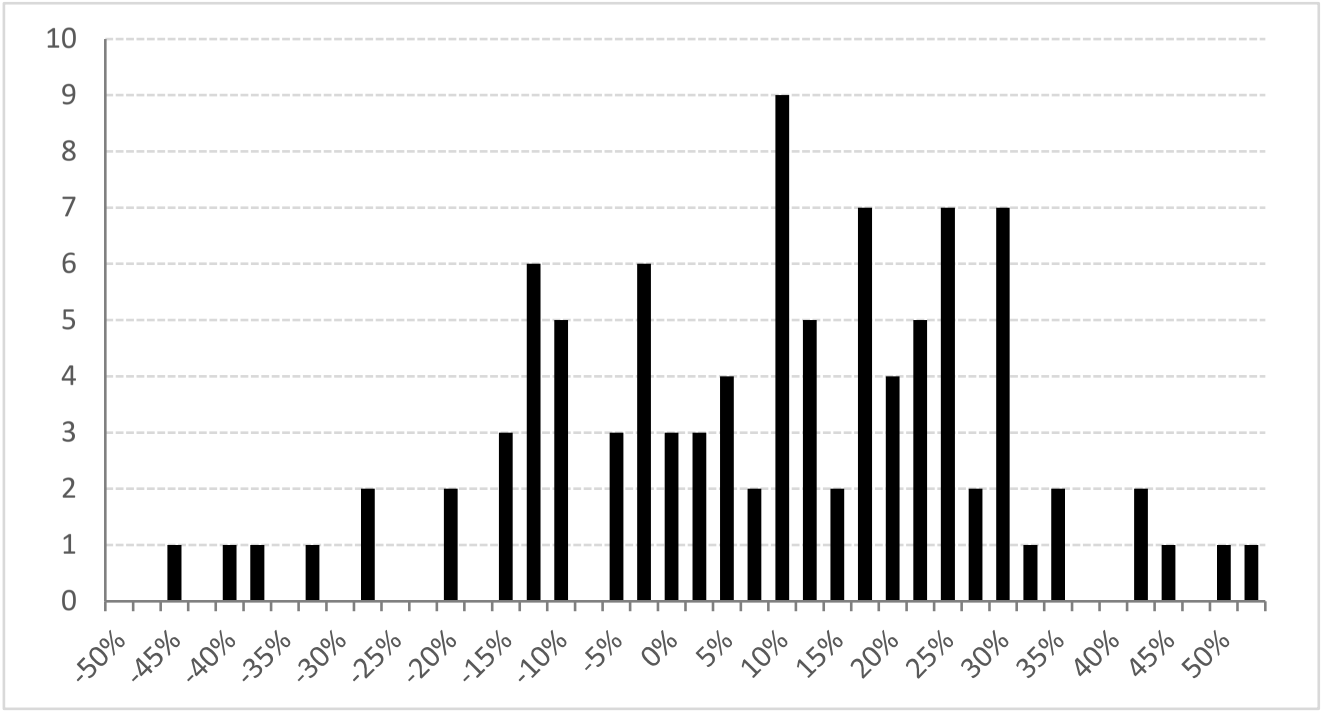
Mr. Keller's Electric Proxy Group

Company Name	Yield	Growth	K
Dominion Energy	4.91 %	8.70 %	13.61 %
Duke Energy	3.82	6.23	10.05
Consol. Edison	3.57	5.80	9.37
Eversource Energy	5.13	5.61	10.74
Exelon Corporation	4.10	6.41	10.51
FirstEnergy Corp.	4.51	5.66	10.17
NextEra Energy	3.42	7.97	11.39
Public Serv. Enterpr	3.33	6.82	10.15
PPL Corp.	3.56	7.47	11.03
Standard Deviation			1.15 %

Source of Information:
Mr. Patel's I&E Exhibit No. 2, Schedules 4 & 5, and Mr. Keller's I&E Exhibit No. 2, Schedules 6 & 7.

Valley Energy, Inc. / Citizens' Electric Company of Lewisburg, PA / Wellsboro Electric Company

Frequency Distribution of Market Risk Premium, 1926 - 2024



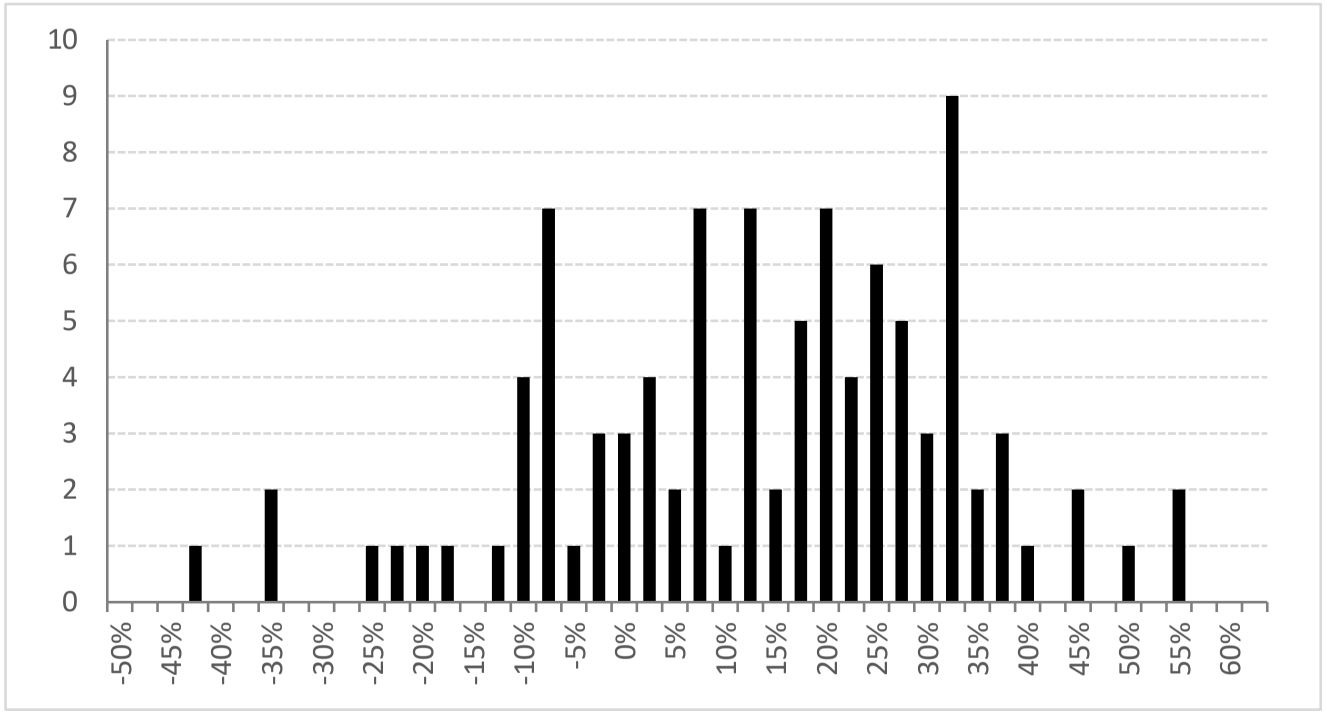
Average MRP from Direct	Rank
8.15%	48.40%

Average MRP from Rebuttal	Rank
8.86%	49.40%

Exhibit__(DWD-1R)
Schedule DWD-4R
Page 1 of 2

Valley Energy, Inc. / Citizens' Electric Company of Lewisburg, PA / Wellsboro Electric Company

Frequency Distribution of Observed Market Returns, 1926 - 2024



Average Return from Direct	Rank
12.70%	47.20%

Average Return from Rebuttal	Rank
13.46%	47.80%

Source: Kroll, 2023 SBBI, Appendix A-1, A-7; Cost of Capital Navigator

FINANCIAL QUARTERLY
R · E · V · I · E · W

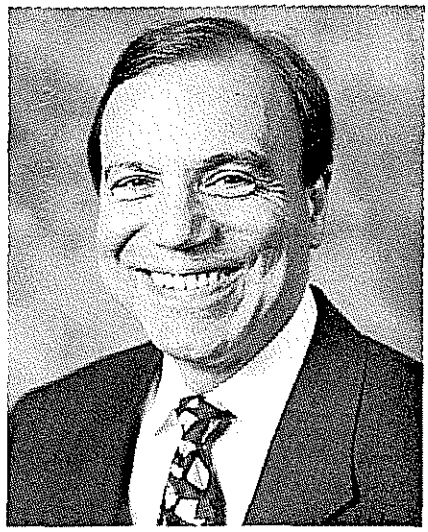
Comparable Earnings: New Life for an Old Precept

by
Frank J. Hanley
Pauline M. Ahern

Reprinted from the American Gas Association's *Financial Quarterly Review*
Summer 1994 edition, Arlington, Va.

Comparable Earnings: New Life for an Old Precept

Accelerating deregulation has greatly increased the investment risk of natural gas utilities. As a result, the authors believe it more appropriate than ever to employ the comparable earnings model. We believe our application of the model overcomes the greatest traditional objection to it — lack of comparability of the selected non-utility proxy firms. Our illustration focuses on a target gas pipeline company with a beta of 0.96 — almost equal to the market's beta of 1.00.



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Introduction

The comparable earnings model used to determine a common equity cost rate is deeply rooted in the standard of "corresponding risk" enunciated in the landmark *Bluefield* and *Hope* decisions of the U.S. Supreme Court.[1] With such solid grounding in the foundations of rate of return regulation, comparable earnings should be accepted as a principal model, along with the currently popular market-based models, provided that its most common criticism, non-comparability of the proxy companies, is overcome.

Our comparable earnings model overcomes the non-comparability issue of the non-utility firms selected as a proxy for the target utility, in this example, a gas pipeline company. We should note that in the absence of common stock prices for the target utility (as with a wholly-owned subsidiary), it is appropriate to use the average of a proxy group of similar risk gas pipeline companies whose common stocks are actively traded. As we will demonstrate, our selection process results in a group of domestic, non-utility firms that is comparable in total risk, the sum of business and financial risk, which reflects both non-diversifiable systematic, or market, risk as well as diversifiable unsystematic, or firm-specific, risk.

Embedded in the Landmark Decisions

As stated in *Bluefield* in 1922: "A public utility is entitled to such rates as will permit it to earn a return ... on investments in other business undertakings which are attended by corresponding risks and uncertainties ..."

In addition, the court stated in *Hope* in 1944: "By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks."

Thus, the "corresponding risk" precept of *Bluefield* and *Hope* predates the use of such market-based cost-of-equity models as the Discounted Cash Flow (DCF) and Capital Asset Pricing (CAPM), which were developed later and are currently popular in rate-base/rate-of-return regulation. Consequently, the comparable earnings model has a longer regulatory and judicial history. However, it has far greater relevance now than ever before in its history because significant deregulation has substantially increased natural gas utilities' investment risk to a level similar to that of non-utility firms. As a result, it is

Comparable Earnings *from page 4*

more important than ever to look to similar-risk non-utility firms for insight into common equity cost rate, especially in view of the deficiencies inherent in the currently popular market-based cost of common equity models, particularly the DCF model.

Despite the fact that the landmark decisions are still regarded as having set the standards for determining a fair rate of return, the comparable earnings model has experienced decreased usage by expert witnesses, as well as less regulatory acceptance over the years. We believe the decline in the popularity of the comparable earnings model, in large measure, is attributable to the difficulty of selecting non-utility proxy firms that regulators will accept as comparable to the target utility. Regulatory acceptance is difficult to gain when the selection process is arbitrary. Our application of the model is objective and consistent with fundamental financial tenets.

Principles of Comparable Earnings

Regulation is a substitute for the competition of the marketplace. Moreover, regulated public utilities compete in the capital markets with all firms, including unregulated non-utilities. The comparable earnings model is based upon the opportunity cost principle; i.e., that the true cost of an investment is the return that could have been earned on the next best available alternative investment of similar risk. Consequently, the comparable earnings model is consistent with regulatory and financial principles, as it is a surrogate for the competition of the marketplace, and investors seek the greatest available rate of return for bearing similar risk.

The selection of comparable firms is the most difficult step in applying the comparable earnings model, as noted by Phillips[2] as well as by Bonbright, Danielsen and Kamerschen.[3] The selection of non-utility proxy firms should result in a sufficiently broad-based group in order to minimize the effect of company-specific aberrations. However, if the selection process is arbitrary, it likely would result in a proxy group that is too broad-based, such as the Standard & Poor's 500 Composite Index or the Value Line Industrial Composite. The use of such groups would require subjective adjustments to the comparable earnings results to reflect risk differences between the group(s) and the target utility, a gas pipeline company in this example.

Authors' Selection Criteria

We base the selection of comparable non-utility firms on market-based, objective, quantitative measures of risk resulting from market prices that subsume investors' assessments of all elements of risk. Thus, our approach is based upon the principle of risk and return; namely, that firms of comparable risk should be expected to earn comparable returns. It is also consistent with the "corresponding risk" standard established in *Bluefield* and *Hope*. We measure total investment risk as the sum of non-diversifiable systematic and diversifiable unsystematic risk. We use the unadjusted beta as a measure of systematic risk and the standard error of the estimate (residual standard error) as a measure of unsystematic risk. Both the unadjusted beta and the residual standard error are derived from a regression of the target utility's security returns relative to the market's returns, which takes the general form:

$$r_{it} = a_i + b_i r_{mt} + e_{it}$$

where:

- r_{it} = tth observation of the ith utility's rate of return
- r_{mt} = tth observation of the market's rate of return
- e_{it} = tth random error term
- a_i = constant least-squares regression coefficient
- b_i = least-squares regression slope coefficient, the unadjusted beta.

As shown by Francis,[4] the total variation or risk of a firm's return, Var (r_i), comes from two sources:

Var (r_i) = total risk of ith asset

$= \text{var}(a_i + b_i r_m + e)$
substituting $(a_i + b_i r_m + e)$ for r_i

$= \text{var}(b_i r_m) + \text{var}(e)$ since $\text{var}(a_i) = 0$

$= b_i^2 \text{ var}(r_m) + \text{var}(e)$ since $\text{var}(b_i r_m) = b_i^2 \text{ var}(r_m)$

= systematic + unsystematic risk

Francis[5] also notes: "The term $\sigma^2(r_i|r_m)$ is called the *residual variance around the regression line* in statistical terms or *unsystematic risk* in capital market theory language. $\sigma^2(r_i|r_m) = \ldots = \text{var}(e)$. The residual variance is the squared standard error in regression language, a measure of unsystematic risk." Application of these criteria results in a group of non-utility firms whose average total investment risk is indeed comparable to that of the target gas pipeline.

As a measure of systematic risk, we use the Value Line unadjusted beta. Beta measures the extent to which market-wide or macro-economic events affect a firm's stock price. We use the unadjusted beta of the target utility as a starting point because it results from the regression of the target utility's security returns relative to the market's returns. Thus, the resulting standard deviation of beta relates to the unadjusted beta. We use the standard deviation of the unadjusted beta to determine the range around it as the selection criterion based on systematic risk.

We use the residual standard error of the regression as a measure of unsystematic risk. The residual standard error reflects the extent to which events specific to the firm's operations affect a firm's stock price. Thus, it is a measure of diversifiable, unsystematic, firm-specific risk.

An Illustration of Authors' Approach

Step One: We begin our approach by establishing the selection criteria as a range of both unadjusted beta and residual standard error of the target gas

continued on page 6

Comparable Earnings *from page 5*

pipeline company.

As shown in table 1, our target gas pipeline company has a Value Line unadjusted beta of 0.90, whose standard deviation is 0.1250. The selection criterion range of unadjusted beta is the unadjusted beta plus (+) and minus (-) three of its standard deviations. By using three standard deviations, 99.73 percent of the comparable unadjusted betas is captured.

Three standard deviations of the target utility's unadjusted beta equals 0.38 (0.1250 x 3 = 0.3750, rounded to 0.38). Consequently, the range of unadjusted betas to be used as a selection criteria is 0.52 - 1.28 (0.52 = 0.90 - 0.38) and (1.28 = 0.90 + 0.38).

Likewise, the selection criterion range of residual standard error equals the residual standard error plus (+) and minus (-) three of its standard deviations. The standard deviation of the residual standard error is defined as: $\sigma/\sqrt{2N}$.

As also shown in table 1, the target gas pipeline company has a residual standard error of 3.7867. According to the above formula, the standard deviation of the residual standard error would be 0.1664 (0.1664 = 3.7867/ $\sqrt{2(259)}$ = 3.7867/22.7596, where 259 = N, the number of weekly price change observations over a period of five years). Three standard deviations of the target utility's residual standard error would be 0.4992 (0.1664 x 3 = .4992). Consequently, the range of residual standard errors to be used as a selection criterion is 3.2875 - 4.2859 (3.2875 = 3.7867 - 0.4992) and (4.2859 = 3.7867 + 0.4992).

Step Two: The step one criteria are applied to Value Line's data base of nearly 4,000 firms for which Value Line derives unadjusted betas and residual standard errors on a weekly basis. All firms with unadjusted betas and residual standard errors within the criteria ranges are then selected.

Step Three: In the regulatory ratemaking environment, authorized common equity return rates are applied to a book-value rate base. Thus, the earnings rates on book common equity, or net worth, of competitive, non-utility firms are highly relevant provided those firms are indeed comparable in total risk to the target gas pipeline. The use of the return rates of other utilities has no relevance because their allowed, and hence subsequently achieved, earnings rates are dependent upon the regulatory

table 1

Summary of the Comparable Earnings Analysis for the Proxy Group of 248 Non-Utility Companies Comparable in Total Risk to the Target Gas Pipeline Company[1]

	1	2	3	4	5	6	7	8
			residual	rate of return on net worth				
	adj. beta	unadj. beta	standard error	3-year average[2]	4-year average[2]	5-year average[2]	5-year projected[3]	
average for the proxy group of 248 non-utility companies comparable in total risk to the target gas pipeline company	0.97	0.92	3.7705					
target gas pipeline company	0.96	0.90[4]	3.7867					
median				11.7%	12.0%	12.6%	15.5%	
average of the median historical returns					12.1%			
conclusion[5]								13.8%

[1]The criteria for selection of the non-utility group was that the non-utility companies be domestic and included in *Value Line Investment Survey*. The non-utility group was selected based on an unadjusted beta range of 0.52 to 1.28 and a residual standard error range of 3.2875 to 4.2859.
[2]Ending 1992.
[3]1996-1998/1997-1999.
[4]The average standard deviation of the target gas pipeline company's unadjusted beta is 0.1250.
[5]Equal weight given to both the average of the 3-, 4- and 5-year historical medians (12.1%) and 5-year projected median rate of return on net worth (15.5%). Thus, 13.8% = (12.1% + 15.5% / 2).
Source: Value Line Inc., March 15, 1994
Value Line Investment Survey

Comparable Earnings *from page 6*

process. Consequently, we believe all utilities must be eliminated to avoid circularity. Moreover, we believe non-domestic firms must be eliminated because their reporting methods differ significantly from U.S. firms.

Step Four: We then eliminated those firms for which Value Line does not publish a "Ratings & Report" in *Value Line Investment Survey* so that the historical and projected returns on net worth[6] are from a consistent source. We use historical returns on net worth for the most recent five years, as well as those projected three to five years into the future. We believe it is logical to evaluate both historical and projected return rates because it is reasonable to assume that investors avail themselves of both when they are available from widely disseminated information services, such as Value Line Inc. The use of Value Line's return rates on net worth understates the common equity return rates for two reasons. First, preferred stock is included in net worth. Second, the net worth return rates are as of the end of each period. Thus, the use of average common equity return rates would yield higher results.

Step Five: Median returns based on the historical average three, four and five years ending 1992 and projected 1996-1998 or 1997-1999 rates of return on net worth are then determined as shown in columns 4 through 7 of table 1. The median is used due to the wide variations and skewness in rates of return on net worth for the non-utility firms as evidenced by the frequency distributions of those returns as shown in illustration 1.

However, we show the average unadjusted beta, 0.92, and residual standard error, 3.7705, for the proxy group in columns 2 and 3 of table 1 because their frequency distributions are not significantly skewed, as shown in illustration 2.

Step Six: Our conclusion of a com-

continued on page 8

Illustration 1

Rates of Return on Net Worth for the Proxy Group of 248 Non-Utility Companies[1]

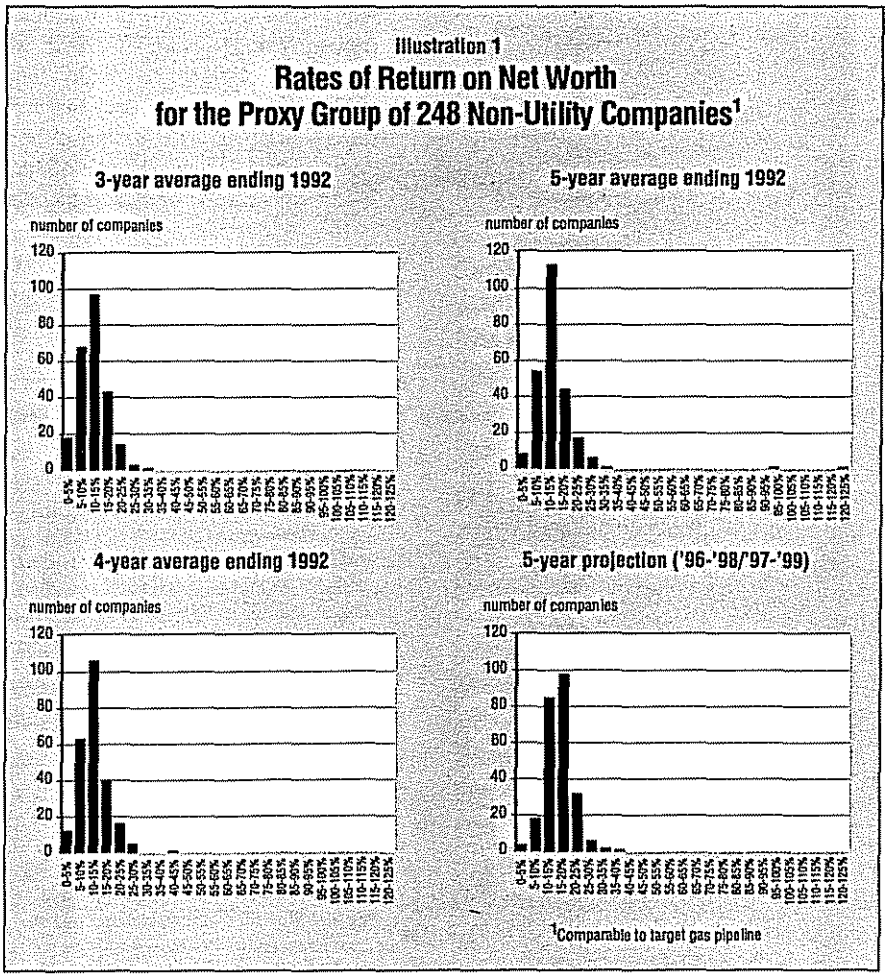
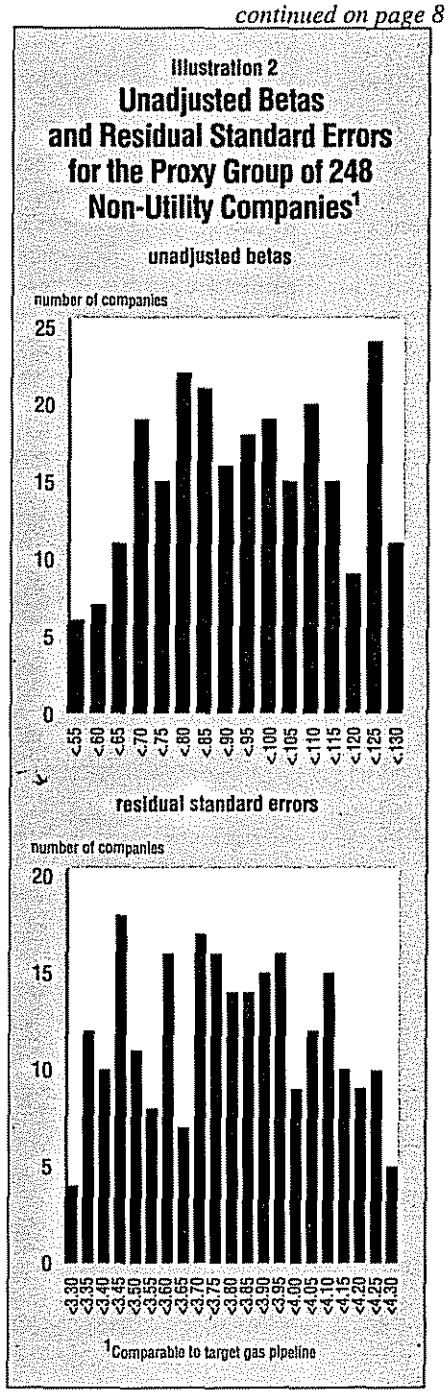


Illustration 2

Unadjusted Betas and Residual Standard Errors for the Proxy Group of 248 Non-Utility Companies[1]



Comparable Earnings *from page 7*

parable earnings cost rate is based upon the mid-point of the average of the median three-, four- and five-year historical rates of return on net worth of 12.1 percent as shown in column 5 and the median projected 1996-1998/1997-1999 rate of return on net worth of 15.5 percent as shown in column 7 of table 1. As shown in column 8, it is 13.8 percent.

Summary

Our comparable earnings approach demonstrates that it is possible to select a proxy group of non-utility firms that is comparable in total risk to a target utility. In our example, the 13.8 percent comparable earnings cost rate is very conservative as it is an expected achieved rate on book common equity (a regulatory allowed rate should be greater) and because it is based on end-of-period net worth. A similar rate on average net worth would be about 20 to 40 basis points higher (i.e., 14.0 to 14.2 percent) and still understate the appropriate regulatory allowed rate of return on book common equity.

Our selection criteria are based upon measures of systematic and unsystematic risk, specifically unadjusted beta and residual standard error. They provide the basis for the objective selection of comparable non-utility firms. Our selection criteria rely on changes in market prices over approximately five years. We compare the aggregate total risk, or the sum of systematic and unsystematic risk, which reflects investors' aggregate assessment of both business and financial risk. Thus, no adjustments are necessary to the proxy group results to compensate for the differences in business risk and financial risk, such as accounting practices and debt/equity ratios. Moreover, it is inappropriate to attempt a comparison of the target utility with any individual firm, or subset of firms, in the proxy group because only the average firm of the group is relevant.

Because the comparable earnings model is firmly anchored in the "corresponding risk" precept established in the landmark court decisions, it is worthy of consideration as a principal model for use in estimating the cost rate of common equity capital of a regulated utility. Our approach to the comparable earnings model produces a proxy group that is indeed comparable in total risk because the selection process is objective and quantitative. It therefore overcomes criticism linked to arbitrary selection processes.

All cost-of-common-equity models, including the DCF and CAPM, are fraught with deficiencies, usually stemming from the many necessary but unrealistic assumptions that underlie them. The effects of the deficiencies of individual models can be mitigated by using more than one model when estimating a utility's common equity cost rate. Therefore, when the non-comparability issue is overcome, the comparable earnings model deserves to receive the same consideration as a primary model, as do the currently popular market-based models. ■

[1] *Bluefield Water Works Improvement Co. v. Public Service Commission*. 262 U.S. 679 (1922) and *Federal Power Commission v. Hope Natural Gas Co.* 320 U.S. 519 (1944).

[2] Charles F. Phillips Jr., The Regulation of Public Utilities: Theory and Practice. Public Utilities Reports Inc., 1988. p. 379.

[3] James C. Bonbright, Albert L. Danielsen and David R. Kamerschen. Principles of Public Utilities Rates. 2nd edition. Public Utilities Reports Inc. 1988, p. 329.

[4] Jack Clark Francis. Investments: Analysis and Management. 3rd edition. McGraw-Hill Book Co., 1980, p. 363.

[5] Id., p. 548.

[6] Returns on net worth must be used when relying on Value Line data because returns on book common equity for non-utility firms are not available from Value Line.

Report Lists Pipeline, Storage Projects

More than $9 billion worth of projects to expand the nation's natural gas pipeline network are in various stages of development, according to an A.G.A. report. These projects involve nearly 8,000 miles of new pipelines and capacity additions to existing lines and represent 15.3 billion cubic feet (Bcf) per day of new pipeline capacity.

During 1993 and early 1994, construction on 3,100 miles of pipeline was completed or under way, at a cost of nearly $4 billion, says A.G.A. These projects are adding 5.4 Bcf in daily delivery capacity nationwide.

Among the projects completed in 1993 were Pacific Gas Transmission Co.'s 805 miles of looping that allows increased deliveries of Canadian gas to the West Coast; Northwest Pipeline Corp.'s addition of 433 million cubic feet of daily capacity for customers in the Pacific Northwest and Rocky Mountain areas; and the 156-mile Empire State Pipeline in New York.

In addition, major construction projects were started on the systems of Texas Eastern Transmission Corp. and Algonquin Gas Transmission Co. — both subsidiaries of Panhandle Eastern Corp. — and along Florida Gas Transmission Co.'s pipeline.

The report goes on to discuss another $5 billion in proposed projects, which, if completed, will add nearly 5,000 miles of pipeline and 9.8 Bcf per day in capacity, much of it serving Florida and West Coast markets.

A.G.A. also identifies 47 storage projects and says that if all of them are built, existing storage capacity will increase by more than 500 Bcf, or 15 percent.

For a copy of *New Pipeline Construction: Status Report 1993-94* (#F00103), call A.G.A. at (703) 841-8490. Price per copy is $6 for employees of member companies and associates and $12 for other customers.

Investments: Analysis and Management

Fifth Edition

Jack Clark Francis

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Investments: Analysis and Management

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Beta Measurements The beta coefficient is an *index of systematic risk.* Beta coefficients may be used for ranking the systematic risk of different assets. If the beta is larger than 1, $b > 1.0$, then the asset is more volatile than the market and is called an **aggressive asset.** If the beta is less than 1, $b < 1.0$, the asset is a **defensive asset;** its price fluctuations are less volatile than the market's. Figure 10-1 illustrates the characteristic lines for three different assets that have low, medium, and high levels of beta (or undiversifiable risk).

Figure 10-2 shows that IBM is a stock with an average amount of systematic risk. IBM's beta of 1.02 indicates that its return tends to increase 2 percent more than the return on the market average when the market is rising. When the market falls, IBM's return tends to fall 2 percent more than the market's. The characteristic line for IBM has an above average correlation coefficient of $\rho = .7495$, indicating that the returns on this security follow its particular characteristic line slightly more closely than those of the average stock.

Partitioning Risk Total risk can be measured by the variance of returns, denoted Var(r). This measure of *total risk is partitioned into its systematic and unsystematic components in Equation (10-8).*[7]

$$\begin{aligned} \text{Var}(r_i) &= \text{total risk of } i\text{th asset} \\ &= \text{Var}(a_i + b_i r_{m,t} + e_{i,t}) \\ &\quad \text{by substituting } (a_i + b_i r_{m,t} + e_{i,t}) \text{ for } r_{i,t} \\ &= 0 + \text{Var}(b_i r_{m,t}) + \text{Var}(e_{i,t}) \\ &\quad \text{since Var}(a_i) = 0 \end{aligned} \tag{10-8}$$

$$\begin{aligned} \text{Var}(r_i) &= b_i^2 \text{ Var}(r_m) + \text{Var}(e) \qquad \text{since Var}(b_i r_m) = b_i^2 \text{ Var}(r_m) \\ &= \text{systematic} + \text{unsystematic risk} \end{aligned} \tag{10-8a}$$

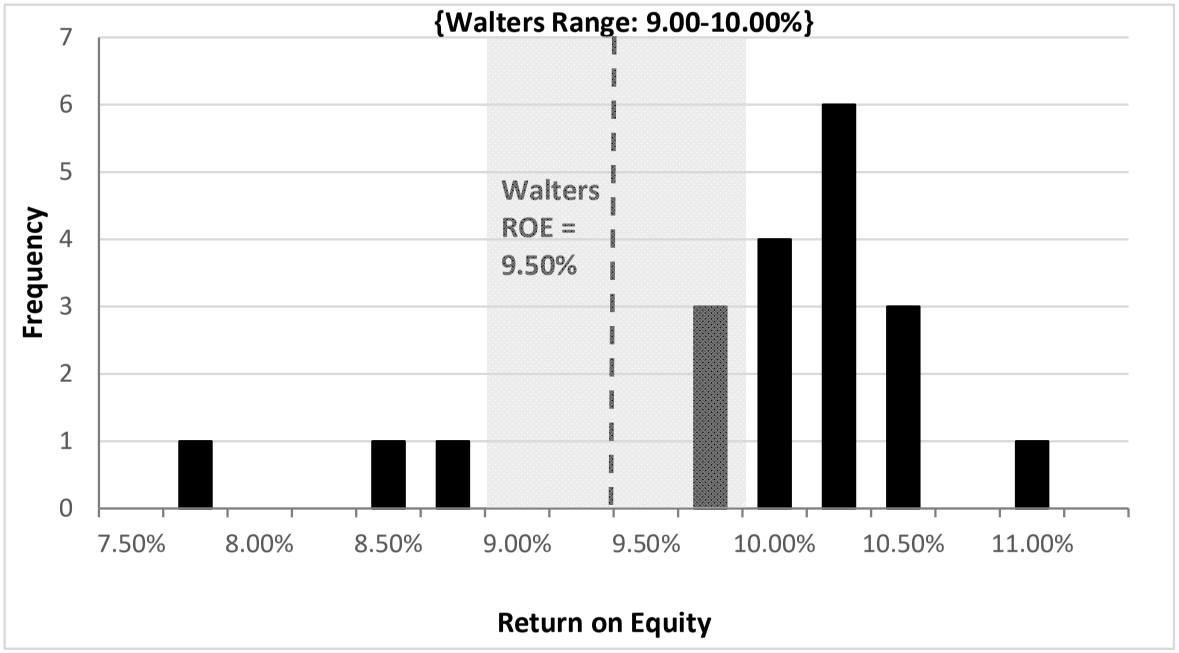
$$.01389 = .00780 + .00609 \qquad \text{for IBM}$$

The unsystematic risk measure Var(e) is called in regression language the *residual variance* or, synonymously, the *standard error squared.*

Undiversifiable Proportion The percentage of total risk that is systematic can be measured by the coefficient of determination ρ^2 (that is, the characteristic line's squared correlation coefficient).

[7]In this context, **partition** is a technical statistical term that means to divide the total variance into *mutually exclusive* and *exhaustive* pieces. This partition is only possible if the returns from the market are statistically independent from the residual error terms that occur simultaneously, $\text{Cov}(r_{m,t}, e_{i,t}) = 0$. The mathematics of regression analysis will orthogonalize the residuals and thus ensure that the needed statistical independence exists.

Valley Energy, Inc. / Citizens' Electric Company of Lewisburg, PA / Wellsboro Electric Company
Frequency Distribution of Mr. Walters' ROE Results



Number of results below 9.50%:	3	15%
Number of results above 9.50%:	17	85%
Number of results above 10.00%:	10	50%

Exhibit__(DWD-1R)
Schedule DWD-7R
Page 1 of 1

Valley Energy, Inc. / Citizens' Electric Company of Lewisburg, PA / Wellsboro Electric Company
Gross Domestic Product by Industry
from 1947 - 2024

Industry	1947	2024	CAGR
Agriculture, forestry, fishing, and hunting	19.9	248.4	3.33%
Mining	5.8	393.7	5.63%
Utilities	3.5	437.3	**6.47%**
Construction	8.9	1,312.3	**6.70%**
Manufacturing	63.4	2,913.1	5.10%
Wholesale trade	15.6	1,706.8	6.29%
Retail trade	23.2	1,841.7	5.85%
Transportation and warehousing	14.1	969.2	5.65%
Information	7.7	1,569.5	**7.15%**
Finance, insurance, real estate, rental, and leasing	25.8	6,190.0	**7.38%**
Professional and business services	8.2	3,847.4	**8.32%**
Educational services, health care, and social assistance	4.6	2,542.0	**8.55%**
Arts, entertainment, recreation, accommodation, and food services	8.0	1,293.2	**6.83%**
Other services, except government	7.5	626.7	5.92%
Government	33.5	3,293.7	6.14%
Total Gross domestic product	249.7	29,185.0	6.38%

Source: Bureau of Economic Analysis

Industry	Gross Domestic Product	1947-2024 CAGR	Beginning Year	Ending Year	Gross Domestic Product In Ending Year	% of Total
Agriculture, forestry, fishing, and hunting	248.4	3.33%	1	276	2.E+06	
Mining	393.7	5.63%	1	276	1.E+09	
Utilities	437.3	6.47%	1	276	1.E+10	
Construction	1,312.3	6.70%	1	276	8.E+10	
Manufacturing	2,913.1	5.10%	1	276	3.E+09	
Wholesale trade	1,706.8	6.29%	1	276	3.E+10	
Retail trade	1,841.7	5.85%	1	276	1.E+10	
Transportation and warehousing	969.2	5.65%	1	276	4.E+09	
Information	1,569.5	7.15%	1	276	3.E+11	
Finance, insurance, real estate, rental, and leasing	6,190.0	7.38%	1	276	2.E+12	
Professional and business services	3,847.4	8.32%	1	276	1.E+13	
Educational services, health care, and social assistance	2,542.0	8.55%	1	276	2.E+13	50.02%
Arts, entertainment, recreation, accommodation, and food services	1,293.2	6.83%	1	276	1.E+11	
Other services, except government	626.7	5.92%	1	276	5.E+09	
Government	3,293.7	6.14%	1	276	5.E+10	
Total Gross domestic product	29,185.0				3.E+13	

Industry	Gross Domestic Product	1947-2024 CAGR	Beginning Year	Ending Year	Gross Domestic Product In Ending Year	% of Total
Agriculture, forestry, fishing, and hunting	248.4	3.33%	1	5,939	9.E+86	
Mining	393.7	5.63%	1	5,939	8.E+143	
Utilities	437.3	6.47%	1	5,939	2.E+164	
Construction	1,312.3	6.70%	1	5,939	2.E+170	
Manufacturing	2,913.1	5.10%	1	5,939	5.E+131	
Wholesale trade	1,706.8	6.29%	1	5,939	3.E+160	
Retail trade	1,841.7	5.85%	1	5,939	6.E+149	
Transportation and warehousing	969.2	5.65%	1	5,939	5.E+144	
Information	1,569.5	7.15%	1	5,939	2.E+181	
Finance, insurance, real estate, rental, and leasing	6,190.0	7.38%	1	5,939	2.E+187	
Professional and business services	3,847.4	8.32%	1	5,939	4.E+209	
Educational services, health care, and social assistance	2,542.0	8.55%	1	5,939	8.E+214	100.000%
Arts, entertainment, recreation, accommodation, and food services	1,293.2	6.83%	1	5,939	3.E+173	
Other services, except government	626.7	5.92%	1	5,939	1.E+151	
Government	3,293.7	6.14%	1	5,939	2.E+157	
Total Gross domestic product	29,185.0				8.E+214	

Source: Bureau of Economic Analysis

Valley Energy, Inc. / Citizens' Electric Company of Lewisburg, PA / Wellsboro Electric Company
Retention Ratio Regression Analysis

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.366
R Square	0.134
Adjusted R Square	0.133
Standard Error	0.263
Observations	1062

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	11.273	11.273	163.486	0.000
Residual	1060	73.089	0.069		
Total	1061	84.362			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*
Intercept	0.154	0.011	14.575	0.000	0.133	0.175
Retention Ratio	-0.270	0.021	-12.786	0.000	-0.312	-0.229

Valley Energy, Inc. / Citizens' Electric Company of Lewisburg, PA / Wellsboro Electric Company
Market-to-Book Ratios, Earnings / Book Ratios and
Inflation for Standard & Poor's Industrial Index and
the Standard & Poor's 500 Composite Index
from 1947 through 2024

Year	Market-to-Book Ratio (1) S&P Industrial Index (3)	Market-to-Book Ratio (1) S&P 500 Composite Index (3)	Earnings / Book Common Equity Ratio (2) S&P Industrial Index (3)	Earnings / Book Common Equity Ratio (2) S&P 500 Composite Index (3)	Inflation (4)	Earnings / Book Common Equity Ratio - Net of Inflation S&P Industrial Index (3)	Earnings / Book Common Equity Ratio - Net of Inflation S&P 500 Composite Index (3)
1947	1.23	NA	13.0 %	NA	9.0 %	4.0 %	NA
1948	1.13	NA	17.3	NA	2.7	14.6	NA
1949	1.00	NA	16.3	NA	(1.8)	18.1	NA
1950	1.16	NA	18.3	NA	5.8	12.5	NA
1951	1.27	NA	14.4	NA	6.0	8.4	NA
1952	1.29	NA	12.7	NA	0.9	11.8	NA
1953	1.21	NA	12.7	NA	0.6	12.1	NA
1954	1.45	NA	13.5	NA	(0.4)	13.9	NA
1955	1.81	NA	16.0	NA	0.4	15.6	NA
1956	1.92	NA	13.7	NA	2.8	10.9	NA
1957	1.71	NA	12.5	NA	3.0	9.5	NA
1958	1.70	NA	9.8	NA	1.8	8.0	NA
1959	1.94	NA	11.2	NA	1.5	9.7	NA
1960	1.82	NA	10.3	NA	1.4	8.9	NA
1961	2.01	NA	9.8	NA	0.7	9.1	NA
1962	1.83	NA	10.9	NA	1.2	9.7	NA
1963	1.94	NA	11.4	NA	1.6	9.8	NA
1964	2.18	NA	12.3	NA	1.2	11.1	NA
1965	2.21	NA	13.2	NA	1.9	11.3	NA
1966	2.00	NA	13.2	NA	3.4	9.8	NA
1967	2.05	NA	12.1	NA	3.3	8.8	NA
1968	2.17	NA	12.6	NA	4.7	7.9	NA
1969	2.10	NA	12.1	NA	5.9	6.2	NA
1970	1.71	NA	10.4	NA	5.6	4.8	NA
1971	1.99	NA	11.2	NA	3.3	7.9	NA
1972	2.16	NA	12.0	NA	3.4	8.6	NA
1973	1.96	NA	14.6	NA	8.9	5.7	NA
1974	1.39	NA	14.8	NA	12.1	2.7	NA
1975	1.34	NA	12.3	NA	7.1	5.2	NA
1976	1.51	NA	14.5	NA	5.0	9.5	NA
1977	1.38	NA	14.6	NA	6.7	7.9	NA
1978	1.25	NA	15.3	NA	9.0	6.3	NA
1979	1.23	NA	17.2	NA	13.3	3.9	NA
1980	1.31	NA	15.6	NA	12.4	3.2	NA
1981	1.24	NA	14.9	NA	8.9	6.0	NA
1982	1.17	NA	11.3	NA	3.8	7.5	NA
1983	1.45	NA	12.2	NA	3.8	8.4	NA
1984	1.46	NA	14.6	NA	4.0	10.6	NA
1985	1.67	NA	12.2	NA	3.8	8.4	NA
1986	2.02	NA	11.5	NA	1.2	10.3	NA
1987	2.50	NA	15.7	NA	4.3	11.4	NA
1988	2.13	NA	19.0	NA	4.4	14.6	NA
1989	2.56	NA	18.5	NA	4.6	13.9	NA
1990	2.63	NA	16.3	NA	6.3	10.0	NA
1991	2.77	NA	10.8	NA	3.0	7.8	NA
1992	3.29	NA	13.0	NA	3.0	10.0	NA
1993	3.72	NA	15.7	NA	2.8	12.9	NA
1994	3.73	NA	23.0	NA	2.6	20.4	NA
1995	4.06	2.64	22.9	16.0	2.5	20.4	13.5
1996	4.79	3.00	24.8	16.8	3.4	21.4	13.4
1997	5.88	3.53	24.6	16.3	1.7	22.9	14.6
1998	7.13	4.16	21.3	14.5	1.6	19.7	12.9
1999	8.27	4.76	25.2	17.1	2.7	22.5	14.4
2000	7.51	4.51	23.9	16.2	3.4	20.5	12.8
2001	NA	3.50	NA	7.4	1.6	NA	5.8
2002	NA	2.93	NA	8.3	2.5	NA	5.8
2003	NA	2.78	NA	14.1	2.0	NA	12.1
2004	NA	2.91	NA	15.3	3.3	NA	12.0
2005	NA	2.78	NA	16.4	3.3	NA	13.1
2006	NA	2.77	NA	17.0	2.5	NA	14.5
2007	NA	2.84	NA	12.8	4.1	NA	8.7
2008	NA	2.24	NA	3.0	(0.0)	NA	3.0
2009	NA	1.87	NA	10.6	2.8	NA	7.8
2010	NA	2.09	NA	14.2	1.4	NA	12.8
2011	NA	2.07	NA	14.6	3.1	NA	11.5
2012	NA	2.14	NA	13.5	1.8	NA	11.8
2013	NA	2.39	NA	14.5	1.5	NA	13.0
2014	NA	2.66	NA	14.2	0.7	NA	13.5
2015	NA	2.73	NA	11.8	0.6	NA	11.2
2016	NA	2.72	NA	12.5	2.1	NA	10.5
2017	NA	3.10	NA	13.8	2.1	NA	11.6
2018	NA	3.15	NA	15.8	2.0	NA	13.8
2019	NA	3.22	NA	15.8	2.3	NA	13.5
2020	NA	3.25	NA	10.2	1.3	NA	8.9
2021	NA	4.39	NA	20.4	7.2	NA	13.3
2022	NA	4.12	NA	17.00	6.4	NA	10.6
2023	NA	4.11	NA	18.39	3.3	NA	15.1
2024	NA	4.89	NA	19.05	2.9	NA	16.2

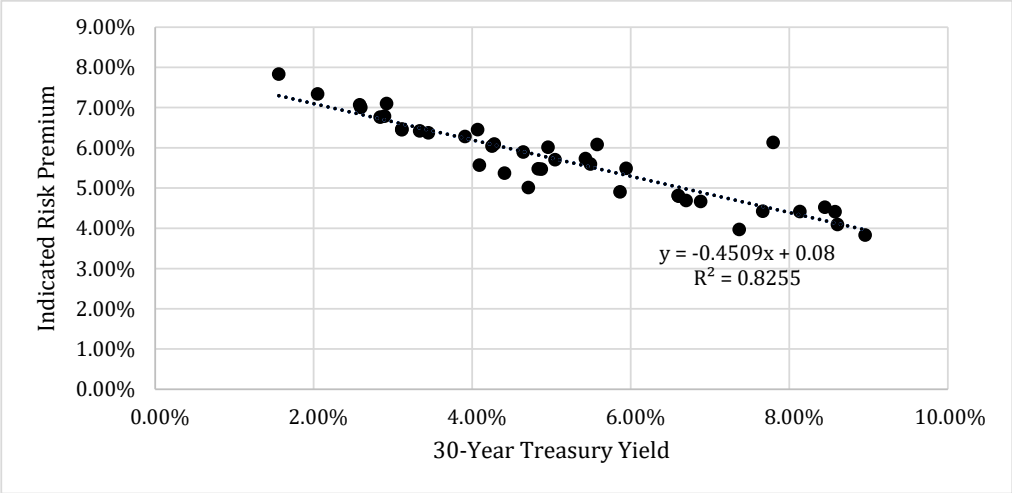
Notes:

(1) Market-to-Book Ratio equals average of the high and low market price for the year divided by the average book value.
(2) Earnings/Book equals earnings per share for the year divided by the average book
(3) On January 2, 2001 Standard & Poor's released Global Industry Classification Standard (GICS) price indexes for all Standard & Poor's U.S. indexes. As a result, all S&P Indexes have been calculated with a common base of 100 at a start date of December 31, 1994. Also, the GICS industrial sector is not comparable to the former S&P Industrial Index and data for the former S&P Industrial Index was discontinued.
(4) As measured by the Consumer Price Index (CPI).

Sources of Information:

Standard & Poor's Security Price Index Record, 2000 Edition, p. 40.
Standard & Poor's Statistical Service, Current Statistics, March 2013, p. 30.
Kroll SBBI 2023 Yearbook Appendix A Tables, Stocks, Bonds, Bills, and Inflation | 1926-2022.
finance.yahoo.com
Bloomberg Professional Services

Valley Energy, Inc. / Citizens' Electric Company of Lewisburg, PA / Wellsboro Electric Company
Mr. Walters' Corrected Electric Risk Premium Model - Treasury Bond



Constant	Slope	Prospective 30-Year Treasury Yield (1)	Risk Premium	Return on Equity
8.00%	-45.09%	4.56%	5.94%	10.50%

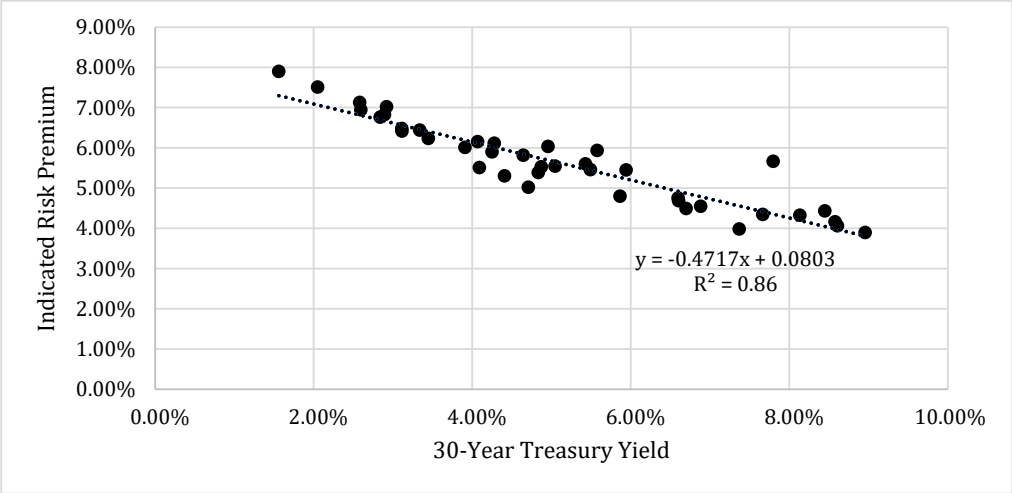
Notes:

(1) For reasons explained in the direct and rebuttal testimonies, the appropriate risk-free rate for cost of capital purposes is the average forecast of 30 year Treasury Bonds per the consensus of nearly 50 economists reported in Blue Chip Financial Forecasts. The projection of the risk-free rate is illustrated below:

Second Quarter 2025	4.80	%
Third Quarter 2025	4.70	
Fourth Quarter 2025	4.60	
First Quarter 2026	4.60	
Second Quarter 2026	4.60	
Third Quarter 2026	4.50	
2027-2031	4.40	
2032-2036	4.30	
	4.56	%

Sources: CCW-10; *Blue Chip Financial Forecasts* , June 2, 2025

Valley Energy, Inc. / Citizens' Electric Company of Lewisburg, PA / Wellsboro Electric Company
Mr. Walters' Corrected Gas Risk Premium Model - Treasury Bond



Constant	Slope	Prospective 30-Year Treasury Yield (1)	Risk Premium	Return on Equity
8.03%	-47.17%	4.56%	5.88%	10.44%

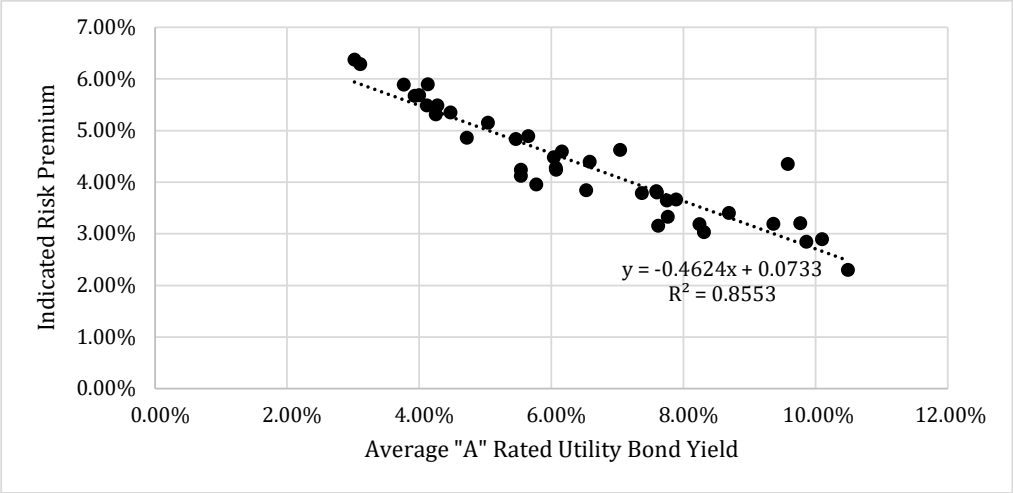
Notes:

(1) For reasons explained in the direct and rebuttal testimonies, the appropriate risk-free rate for cost of capital purposes is the average forecast of 30 year Treasury Bonds per the consensus of nearly 50 economists reported in Blue Chip Financial Forecasts. The projection of the risk-free rate is illustrated below:

Second Quarter 2025	4.80	%
Third Quarter 2025	4.70	
Fourth Quarter 2025	4.60	
First Quarter 2026	4.60	
Second Quarter 2026	4.60	
Third Quarter 2026	4.50	
2027-2031	4.40	
2032-2036	4.30	
	4.56	%

Sources: CCW-10; *Blue Chip Financial Forecasts* , June 2, 2025

Valley Energy, Inc. / Citizens' Electric Company of Lewisburg, PA / Wellsboro Electric Company
Mr. Walters' Corrected Electric Risk Premium Model - A Utility Bond



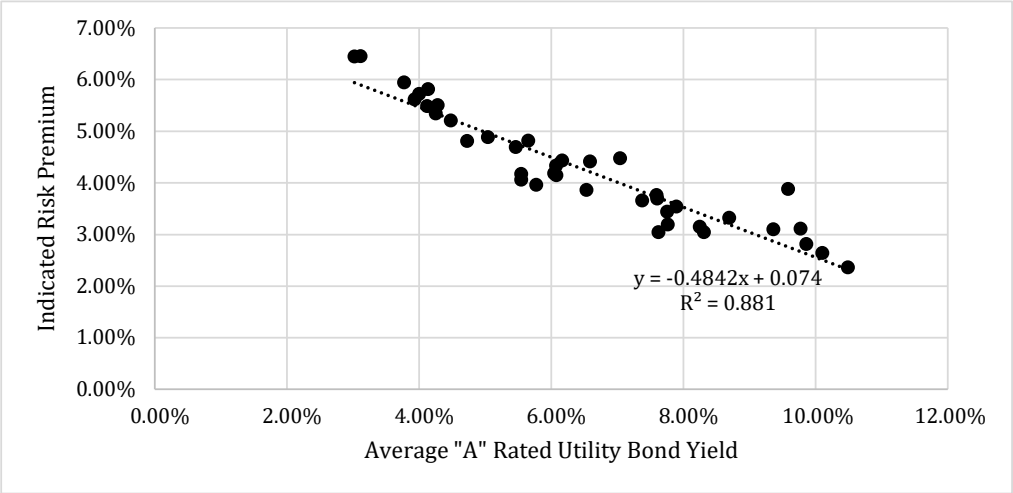
Constant	Slope	Prospective A Utility	Risk Premium	Return on Equity
7.33%	-46.24%	5.71%	4.69%	10.40%

Notes:

(1) The appropriate Prospective A Utility Yield takes the average yield spread of A2 rated public utility bonds over Aaa rated corporate bonds from Bloomberg Professional Service. The spread is added to consensus forecast of Moody's Aaa Rated Corporate bonds from *Blue Chip Financial Forecasts.*

Sources: CCW-11; *Blue Chip Financial Forecasts* , June 2, 2025; Bloomberg Professional.

Valley Energy, Inc. / Citizens' Electric Company of Lewisburg, PA / Wellsboro Electric Company
Mr. Walters' Corrected Gas Risk Premium Model - A Utility Bond



Constant	Slope	Prospective A Utility	Risk Premium	Return on Equity
7.40%	-48.42%	5.71%	4.63%	10.34%

Notes:

(1) The appropriate Prospective A Utility Yield takes the average yield spread of A2 rated public utility bonds over Aaa rated corporate bonds from Bloomberg Professional Service. The spread is added to consensus forecast of Moody's Aaa Rated Corporate bonds from *Blue Chip Financial Forecasts.*

Sources: CCW-11; *Blue Chip Financial Forecasts* , June 2, 2025; Bloomberg Professional.

Valley Energy, Inc. / Citizens' Electric Company of Lewisburg, PA / Wellsboro Electric Company
Indicated Common Equity Cost Rate
Through Use of a Risk Premium Model
Using an Adjusted Total Market Approach

Line No.		
1.	Prospective Yield on Aaa Rated Corporate Bonds (1)	5.25 %
2.	Adjustment to Reflect Yield Spread Between Aaa Rated Corporate Bonds and A2 Rated Public Utility Bonds	0.46 (2)
3.	Adjusted Prospective Yield on A2 Rated Public Utility Bonds	5.71 %

Notes: (1) Consensus forecast of Moody's Aaa Rated Corporate bonds from Blue Chip Financial Forecasts as derived below:

Second Quarter 2025	5.40 %
Third Quarter 2025	5.40
Fourth Quarter 2025	5.30
First Quarter 2026	5.30
Second Quarter 2026	5.20
Third Quarter 2026	5.20
2027-2031	5.10
2032-2036	5.10
	5.25 %

Notes: (2) The average yield spread of A2 rated public utility bonds over Aaa rated corporate bonds from March 2025 through May 2025.

Source of Information:
Blue Chip Financial Forecasts , June 2, 2025
Bloomberg Professional Service

Valley Energy, Inc. / Citizens' Electric Company of Lewisburg, PA / Wellsboro Electric Company
Interest Rates and Bond Spreads for
Moody's Corporate and Public Utility Bonds

Selected Bond Yields

	[1] Aaa Rated Corporate Bond	[2] A2 Rated Public Utility Bond
Mar-2025	5.29 %	5.72 %
Apr-2025	5.45	5.91
May-2025	5.54	6.05
Average	5.43 %	5.89 %

Selected Bond Spreads

A2 Rated Public Utility Bonds Over Aaa Rated Corporate Bonds:

0.46 % (1)

Notes:
(1) Column [2] - Column [1].

Source of Information:
Bloomberg Professional Service

Valley Energy, Inc. / Citizens' Electric Company of Lewisburg, PA / Wellsboro Electric Company
Comparison of Market Return Measures

	[1]	[2]	[3]
Year	Actual Market Return (1)	Long Term Average Market Return (2)	Kroll (3)
2009	26.46%	11.67%	10.50%
2010	15.06%	11.85%	10.08%
2011	2.11%	11.88%	9.63%
2012	16.00%	11.77%	10.00%
2013	32.39%	11.82%	9.50%
2014	13.69%	12.05%	9.00%
2015	1.38%	12.07%	9.00%
2016	11.96%	11.95%	9.00%
2017	21.83%	11.95%	9.00%
2018	-4.38%	12.06%	8.50%
2019	31.49%	11.88%	9.00%
2020	18.40%	12.09%	8.00%
2021	28.71%	12.16%	8.00%
2022	-18.11%	12.33%	8.00%
2023	26.61%	12.02%	9.50%
2024	25.62%	12.16%	9.00%
Sum	249.22%	191.71%	145.71%
Forecast Bias (4)		**76.93%**	**58.47%**

Notes:
(1) Source: Kroll, 2023 SBBI, Appendix A-1, A-7; Cost of Capital Navigator
(2) Rolling historic long-term average of data in Column 1 since 1926
(3) Source: Kroll Recommended ERP + Corresponding Risk-Free Rate
(4) Sum of forecasts divided by sum of actual observations

Valley Energy, Inc. / Citizens' Electric Company of Lewisburg, PA / Wellsboro Electric Company
Mr. Walters Corrected CAPM

CAPM Return

Line	Description	Kroll MRP (1)	Risk Premium Derived MRP (2)	Average FERC S&P 500 DCF Derived MRP (3)
1	Risk-Free Rate (4)	4.56%	4.56%	4.56%
2	Market Risk Premium	6.70%	7.20%	7.85%
3	Beta (5) - All	0.84	0.84	0.84
4	CAPM - All	**10.17%**	**10.60%**	**11.14%**
5	ECAPM - All	**10.44%**	**10.89%**	**11.46%**

Sources:

(1) Average of Kroll historic S&P500 market risk premium (7.17%) and Kroll Ibbotson & Chen supply-side market risk premium (6.22%) from Mr. Walters' Workpapers.

(2) Mr. Walters' Workpapers; Blue Chip Financial Forecasts, June 2, 2025.

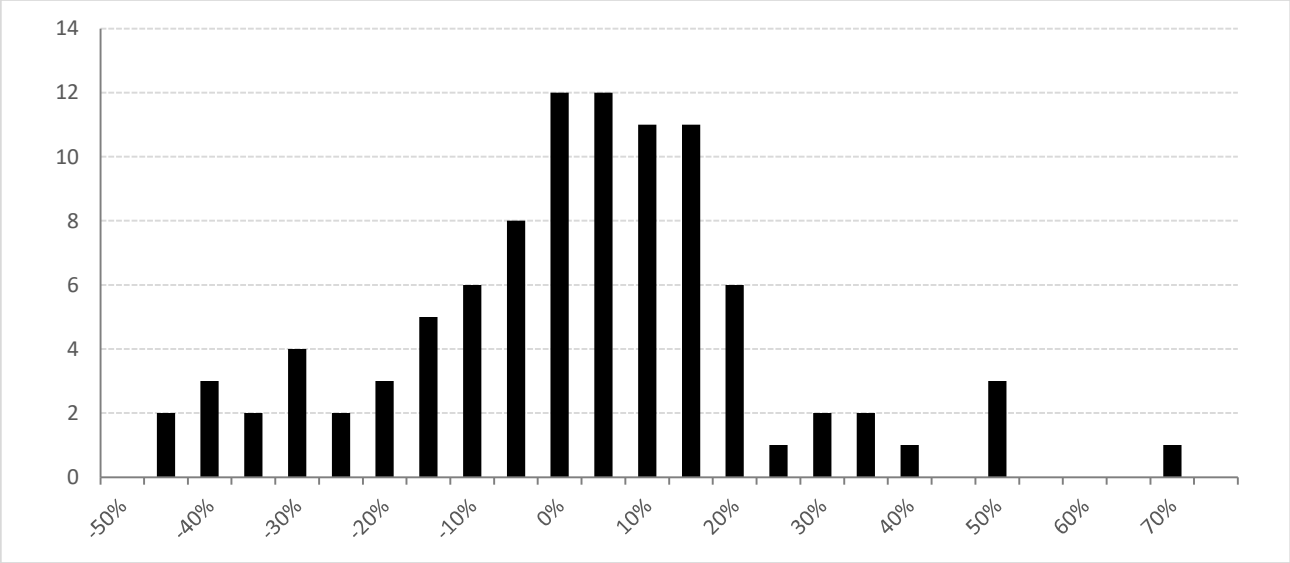
(3) Mr. Walters' Workpapers; Blue Chip Financial Forecasts, June 2, 2025.

(4) For reasons explained in the Rebuttal Testimony, the appropriate risk-free rate for cost of capital purposes is the average forecast of 30 year Treasury Bonds per the consensus of nearly 50 economists reported in Blue Chip Financial Forecasts as of June 2, 2025. The projection of the risk-free rate is illustrated below:

Second Quarter 2025	4.8 %
Third Quarter 2025	4.7
Fourth Quarter 2025	4.6
First Quarter 2026	4.6
Second Quarter 2026	4.6
Third Quarter 2026	4.5
2027-2031	4.4
2032-2036	4.3
	4.56 %

(5) Current betas as published by Value Line Investment Survey as of March 7, April 18, May, 9, and May 23, 2025.

Valley Energy, Inc. / Citizens' Electric Company of Lewisburg, PA / Wellsboro Electric Company
Frequency Distribution of Equity Risk Premiums, 1928 - 2024



	ERP (Natural Gas Proxy Group)	Rank
Direct	5.06%	48.70%

	ERP (Electric Proxy Group)	Rank
Direct	4.93%	48.60%

	ERP (Natural Gas Proxy Group)	Rank
Rebuttal	4.95%	48.60%

	ERP (Electric Proxy Group)	
Rebuttal	4.86%	48.50%

Source of Information: Bloomberg Professional Services; Mergent Bond Record

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	**:**		
	:		
v.	**:**	**Docket Nos.**	**R-2025-**
	:		**R-2025-**
Citizens' Electric Company of Lewisburg, PA,	**:**		
Valley Energy. Inc., and Wellsboro	**:**		
Electric Company	**:**		

DIRECT TESTIMONY

AND EXHIBIT

OF

RYAN M. KUCAN

ON BEHALF OF

CITIZENS' ELECTRIC COMPANY OF LEWISBURG, PA,
VALLEY ENERGY, INC., AND
WELLSBORO ELECTRIC COMPANY

APRIL 30, 2025

TABLE OF CONTENTS

I. Introduction 1
II. Purpose of Testimony 2
III. Summary 2
IV. Capital Structure and Associated Cost Rates 4
V. Conclusion 5

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Ryan M. Kucan. My business address is 1 Speen St., Suite 150, Framingham, MA 01701.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am a Manager at ScottMadden, Inc. ("ScottMadden")

Q. PLEASE SUMMARIZE YOUR PROFESSIONAL EXPERIENCE AND EDUCATIONAL BACKGROUND.

A. I have worked in the regulated utilities industry since 2016 and have been employed by ScottMadden as a consultant for more than six years. At ScottMadden, I have provided support to over 100 utility regulatory proceedings covering topics such as common equity cost rate, rate of return, capital structure, and valuation.

On behalf of the American Gas Association ("AGA"), I help calculate the AGA Gas Index, which serves as the benchmark against which the performance of the American Gas Index Fund ("AGIF") is measured on a monthly basis. The AGA Gas Index and AGIF are a market capitalization weighted index and mutual fund, respectively, comprised of the common stocks of the publicly traded corporate members of the AGA.

I am a member of the Society of Utility and Regulatory Financial Analysts ("SURFA"). In 2023, I was awarded the professional designation "Certified Rate of Return Analyst" by SURFA, which is based on education, experience, and the successful completion of a comprehensive written examination.

I received a Bachelor of Science in Business Administration with concentrations in Finance and Accounting from Northeastern University prior to a Master of Business Administration from the Rotman School of Management at the University of Toronto.

The details of my educational background and professional experience are shown in Appendix A.

II. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is to present evidence on behalf of Valley Energy, Inc. ("Valley"), Citizens' Electric Company of Lewisburg, PA ("Citizens'"), and Wellsboro Electric Company ("Wellsboro") (collectively, "the Companies") supporting their ratemaking capital structure and cost of long-term debt. Company witness Dylan W. D'Ascendis will sponsor the Companies' appropriate return on common equity ("ROE").

Q. HAVE YOU PREPARED AN EXHIBIT IN SUPPORT OF YOUR RECOMMENDATION?

A. Yes. I have prepared Exhibit __ (RMK-1), which consists of Schedules RMK-1 and RMK-2.

III. SUMMARY

Q. WHAT ARE YOUR RECOMMENDED RATEMAKING CAPITAL STRUCTURES FOR THE COMPANIES?

A. I recommend that the Pennsylvania Public Utility Commission (the "Commission")

authorize a ratemaking capital structure that consists of 51.06% long-term debt and 48.94% common equity for the Companies. This recommendation is based on the capital structure of their parent company, C&T Enterprises, as will be discussed below.

Q. WHAT IS YOUR RECOMMENDED COST OF LONG-TERM DEBT FOR THE COMPANIES?

A. I recommend the costs of long-term debt of 5.03% for Valley, 5.47% for Citizens', and 4.85% for Wellsboro, as they are their expected costs of debt at the end of the projected test year.

Q. WHAT ARE THE COMPANIES' REQUESTED ROES?

A. As discussed in Mr. D'Ascendis' direct testimony, the cost of common equity for each of the Companies is 11.65%. The summary of the Companies' requested capital structures and associated cost rates are shown on page 1 of Schedule RMK-1, and on Tables 1, 2, and 3 below.

Table 1: Summary of Recommended Weighted Average Cost of Capital for Valley

Type of Capital	Ratios	Cost Rate	Weighted Cost Rate
Long-Term Debt	51.06%	5.03%	2.57%
Common Equity	48.94%	11.65%	5.70%
Total	100.00%		8.27%

Table 2: Summary of Recommended Weighted Average Cost of Capital for Citizens'

Type of Capital	Ratios	Cost Rate	Weighted Cost Rate
Long-Term Debt	51.06%	5.47%	2.79%
Common Equity	48.94%	11.65%	5.70%
Total	100.00%		8.49%

Table 3: Summary of Recommended Weighted Average Cost of Capital for Wellsboro

Type of Capital	Ratios	Cost Rate	Weighted Cost Rate
Long-Term Debt	51.06%	4.85%	2.48%
Common Equity	48.94%	11.65%	5.70%
Total	100.00%		8.18%

IV. CAPITAL STRUCTURE AND ASSOCIATED COST RATES

Q. WHAT CAPITAL STRUCTURE RATIOS DO YOU RECOMMEND BE EMPLOYED IN DEVELOPING AN OVERALL FAIR RATE OF RETURN APPROPRIATE FOR THE COMPANIES?

A. For Valley, Citizens', and Wellsboro, I recommend the use of the capital structure maintained by the Companies' parent organization, C&T Enterprises, which consists of 51.06% long-term debt and 48.94% common equity.

Q. WHY ARE YOU RECOMMENDING A HYPOTHETICAL CAPITAL STRUCTURE IN THIS PROCEEDING?

A. Valley's, Citizens', and Wellsboro's capital structures at December 31, 2024

contain 69.90%, 86.62%, and 20.46% common equity, respectively.[1] Although these capital structures finance the Companies' rate bases, equity ratios of 69.90%, 86.62%, and 20.46% are inappropriate at this time for ratemaking purposes because they are not consistent with equity ratios of comparable utilities.

Q. HOW DOES YOUR PROPOSED HYPOTHETICAL CAPITAL STRUCTURE COMPARE WITH THE CAPITAL STRUCTURES MAINTAINED BY THE COMPANIES IN THE GAS AND ELECTRIC UTILITY PROXY GROUPS USED TO DETERMINE THE ROE IN THIS PROCEEDING?

A. My proposed hypothetical capital structure is reasonable to use and is consistent with the range of capital structures maintained by the Gas and Electric Utility Proxy Groups used by Mr. D'Ascendis to determine the appropriate ROE for the Company, as shown on pages 1 through 3 of Schedule RMK-2.

Q. WHAT ARE YOUR RECOMMENDED EMBEDDED LONG-TERM DEBT COST RATES FOR THE COMPANIES?

A. I recommend the expected long-term debt cost rates of 5.03% (Valley), 5.47% (Citizens'), and 4.85% (Wellsboro). These long-term debt cost rates are the expected costs of long-term debt for the Companies at the end of the projected test year.

V. <u>CONCLUSION</u>

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

[1] The Companies' December 31, 2024 Return on Equity Report to the Commission.

Appendix A
Ryan M. Kucan, CRRA
Manager

Summary

Ryan Kucan first joined ScottMadden in 2016 as an analyst and rejoined in 2021 as an associate. The majority of his experience has been providing primary support for the preparation of cost-of-capital expert witness testimony to support utility rate case filings before multiple jurisdictions in the United States and Canada. Ryan earned a B.S. in business administration, with a double concentration in accounting and finance, at the D'Amore-McKim School of Business at Northeastern University and an M.B.A. at the University of Toronto's Rotman School of Management. Ryan also earned his Certified Rate of Return Analyst designation in 2023.

Areas of Specialization

- Rates and regulation
- Capital market assessment
- Valuation
- Regulatory strategy and analysis
- Rate-of-return analysis
- Financial modeling

Recent Assignments

- Performed a net-financing-benefits analysis to support utility procurement contracts of offshore wind generation
- Reviewed financial models and state regulatory conditions to assist a potential private equity acquisition of a utility
- Assisted with a market-based valuation of natural gas pipeline assets for a transaction between utilities
- Conducted an analysis to calculate the historical return on equity based on a new model outlined in FERC Opinion No. 531
- Supported expert testimony on the cost of capital for ratemaking purposes before numerous state utility regulatory agencies for electric, natural gas, and water utilities

EXPERT WITNESS TESTIMONY LISTING

Sponsor	Date	Case/Applicant	Docket No.	Subject
New Hampshire Public Utilities Commission				
Unitil Energy Systems, Inc.	05/25	Unitil Energy Systems, Inc.	DE 25-025	Return on Equity

PRIMARY TESTIMONY SUPPORT EXPERIENCE

Sponsor	Date	Case/Applicant	Docket No.	Subject
Alberta Utilities Commission				
AltaLink, L.P., and EPCOR Distribution & Transmission, Inc.	02/23	AltaLink, L.P., and EPCOR Distribution & Transmission, Inc.	Proceeding ID. 27804	Determination of Cost-of-Capital Parameters
Arizona Corporation Commission				
EPCOR Water Arizona, Inc.	06/24	EPCOR Water Arizona, Inc.	Docket No. WS-01303A-24-0130	Rate of Return
Arizona Water Company	05/24	Arizona Water Company – Northern Group	Docket No. W-01445A-24-0117	Rate of Return
Foothills Water & Sewer, LLC	10/23	Foothills Water & Sewer, LLC	Docket No. WS-21182A-23-0292	Rate of Return
Arizona Water Company	12/22	Arizona Water Company – Eastern Group	Docket No. W-01445A-22-0286	Rate of Return
EPCOR Water Arizona, Inc.	08/22	EPCOR Water Arizona, Inc.	Docket No. WS-01303A-22-0236	Rate of Return
Arkansas Public Service Commission				
Summit Utilities Arkansas, Inc.	01/24	Summit Utilities Arkansas, Inc.	Docket No. 23-079-U	Rate of Return
Southwestern Electric Power Co.	07/21	Southwestern Electric Power Co.	Docket No. 21-070-U	Return on Equity
CenterPoint Energy Resources Corp.	05/21	CenterPoint Arkansas Gas	Docket No. 21-004-U	Return on Equity
California Public Utilities Commission				
Southwest Gas Corporation	07/24	Southwest Gas Corporation	Docket No. A24-09-001	Return on Equity
San Gabriel Valley Water Company	05/23	San Gabriel Valley Water Company	Docket No. A23-05-001	Return on Equity
City of Edmonton, Canada				
EPCOR Water Services, Inc.	05/24	EPCOR Water Services, Inc.	Performance Based Regulation Application	Cost of Capital
Commission of the Canada Energy Regulator				
Trans-Northern Pipelines Inc.	11/22	Trans-Northern Pipelines Inc.	Docket No. C-22197	Cost of Capital
Public Service Commission of the District of Columbia				
Washington Gas Light Company	08/24	Washington Gas Light Company	Formal Case No. 1180	Rate of Return
Washington Gas Light Company	04/22	Washington Gas Light Company	Formal Case No. 1169	Rate of Return
Florida Public Service Commission				
Tampa Electric Company	04/21	Tampa Electric Company	Docket No. 20210034-EI	Return on Equity
Illinois Commerce Commission				
Aqua Illinois, Inc.	01/24	Aqua Illinois, Inc.	Docket No. 24-0044	Rate of Return
Kentucky Public Service Commission				
Atmos Energy Corporation	07/22	Atmos Energy Corporation	2022-00222	PRP Rider Rate
Water Service Corporation of KY	06/22	Water Service Corporation of KY	2022-00147	Rate of Return
Atmos Energy Corporation	07/21	Atmos Energy Corporation	2021-00304	PRP Rider Rate
Atmos Energy Corporation	06/21	Atmos Energy Corporation	2021-00214	Rate of Return
Duke Energy Kentucky, Inc.	06/21	Duke Energy Kentucky, Inc.	2021-00190	Return on Equity
Louisiana Public Service Commission				
Utilities, Inc. of Louisiana	05/21	Utilities, Inc. of Louisiana	Docket No. U-36003	Rate of Return

Southwestern Electric Power Company	12/20	Southwestern Electric Power Company	Docket No. U-35441	Return on Equity
Maine Public Utilities Commission				
Northern Utilities, Inc. d/b/a Unitil	05/23	Northern Utilities, Inc. d/b/a Unitil	Docket No. 2023-00051	Return on Equity
Summit Natural Gas of Maine, Inc.	03/22	Summit Natural Gas of Maine, Inc.	Docket No. 2022-00025	Rate of Return
The Maine Water Company	09/21	The Maine Water Company	Docket No. 2021-00053	Rate of Return
Massachusetts Department of Public Utilities				
Unitil Corporation	08/23	Fitchburg Gas & Electric Co. (Elec.)	D.P.U. 23-80	Rate of Return
Unitil Corporation	08/23	Fitchburg Gas & Electric Co. (Gas)	D.P.U. 23-81	Rate of Return
Unitil Corporation	05/22	Fitchburg Gas & Electric Co.	D.P.U. 22-72	Remuneration Rate for Wind project
Maryland Public Service Commission				
Washington Gas Light Company	05/23	Washington Gas Light Company	Case No. 9704	Rate of Return
FirstEnergy Corporation	03/23	Potomac Edison Company	Case No. 9695	Rate of Return
Washington Gas Light Company	08/20	Washington Gas Light Company	Case No. 9651	Rate of Return
Mississippi Public Service Commission				
Great River Utility Operating Co.	07/22	Great River Utility Operating Co.	Docket No. 2022-UN-86	Rate of Return
Missouri Public Service Commission				
Spire Missouri, Inc.	12/20	Spire Missouri, Inc.	Case No. GR-2021-0108	Return on Equity
Public Utilities Commission of Nevada				
Southwest Gas Corporation	09/23	Southwest Gas Corporation	Docket No. 23-09012	Return on Equity
Southwest Gas Corporation	09/21	Southwest Gas Corporation	Docket No. 21-09001	Return on Equity
New Hampshire Public Utilities Commission				
Northern Utilities, Inc. d/b/a Unitil	08/21	Northern Utilities, Inc. d/b/a Unitil	D-DG-21-104	Rate of Return
New Jersey Board of Public Utilities				
FirstEnergy Service Company	03/23	Jersey Central Power & Light Co.	Docket No. ER23030144	Rate of Return
Middlesex Water Company	05/21	Middlesex Water Company	Docket No. WR21050813	Rate of Return
New Mexico Public Regulation Commission				
Southwestern Public Service Co.	01/21	Southwestern Public Service Co.	Case No. 20-00238-UT	Return on Equity
North Carolina Utilities Commission				
Pluris Hampstead, LLC	09/24	Pluris Hampstead, LLC	Docket No. W-1305, Sub 38	Rate of Return
Carolina Water Service, Inc.	07/22	Carolina Water Service, Inc.	Docket No. W-354 Sub 400	Rate of Return
Aqua North Carolina, Inc.	06/22	Aqua North Carolina, Inc.	Docket No. W-218 Sub 573	Rate of Return
Carolina Water Service, Inc.	07/21	Carolina Water Service, Inc.	Docket No. W-354 Sub 384	Rate of Return
Piedmont Natural Gas Co., Inc.	03/21	Piedmont Natural Gas Co., Inc.	Docket No. G-9, Sub 781	Return on Equity
Public Utilities Commission of Ohio				
FirstEnergy	06/24	Ohio Edison Co., Cleveland Electric Illuminating Co., Toledo Edison Co.	Case No. 24-0468-EL-AIR	Rate of Return
Aqua Ohio, Inc.	11/22	Aqua Ohio, Inc.	Case No. 22-1094-WW-AIR	Rate of Return
Duke Energy Ohio, Inc.	10/21	Duke Energy Ohio, Inc.	Case No. 21-887-EL-AIR	Return on Equity
Aqua Ohio, Inc.	07/21	Aqua Ohio, Inc.	Case No. 21-0595-WW-AIR	Rate of Return
Pennsylvania Public Utility Commission				
FirstEnergy	04/24	Pennsylvania Electric Company	Docket No. R-2024-3047068	Rate of Return
Borough of Ambler	06/22	Borough of Ambler – Bureau of Water	Docket No. R-2022-3031704	Rate of Return

Citizens' Electric Company of Lewisburg	05/22	C&T Enterprises	Docket No. R-2022-3032369	Rate of Return
Valley Energy Company	05/22	C&T Enterprises	Docket No. R-2022-3032300	Rate of Return
Community Utilities of Pennsylvania, Inc.	04/21	Community Utilities of Pennsylvania, Inc.	Docket No. R-2021-3025207	Rate of Return
Vicinity Energy Philadelphia, Inc.	04/21	Vicinity Energy Philadelphia, Inc.	Docket No. R-2021-3024060	Rate of Return
Public Utility Commission of Texas				
BVRT Utility Holding Co., LLC	07/24	Texas Water Utilities, LP	Docket No. 56664	Rate of Return
Texas Water Utilities, LP	06/24	Texas Water Utilities, LP	Docket No. 56665	Rate of Return
Southwestern Public Service Co.	02/23	Southwestern Public Service Co.	Docket No. 54634	Return on Equity
Oncor Electric Delivery Co. LLC	05/22	Oncor Electric Delivery Co. LLC	Docket No. 53601	Return on Equity
Southwestern Public Service Co.	02/21	Southwestern Public Service Co.	Docket No. 51802	Return on Equity
Virginia State Corporation Commission				
Washington Gas Light Company	06/22	Washington Gas Light Company	PUR-2022-00054	Return on Equity
Virginia Natural Gas, Inc.	04/21	Virginia Natural Gas, Inc.	PUR-2020-00095	Return on Equity
Public Service Commission of West Virginia				
FirstEnergy Corporation	05/23	Monongahela Power Company and The Potomac Edison Company	Case No. 23-0460-E-42T	Return on Equity
FirstEnergy Corporation	12/21	Monongahela Power Company and The Potomac Edison Company	Case No. 21-0857-E-CN (ELG)	Return on Equity
FirstEnergy Corporation	11/21	Monongahela Power Company and The Potomac Edison Company	Case No. 21-0813-E-P (Solar)	Return on Equity

Valley Energy, Inc. / Citizens' Electric Company of Lewisburg, PA / Wellsboro Electric Company
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Supporting Exhibits Accompanying the Direct Testimony
of Ryan M. Kucan

	Schedule
Summary of Overall Cost of Capital	RMK-1
Capital Structures of the Gas and Electric Utility Proxy Groups	RMK-2

Valley Energy, Inc. / Citizens' Electric Company of Lewisburg, PA / Wellsboro Electric Company
Recommended Capital Structure and Cost Rates
for Ratemaking Purposes

Valley Energy, Inc.

Type of Capital	Ratios(1)	Cost Rate		Weighted Cost Rate
Long-Term Debt	51.06%	5.03%	(2)	2.57%
Common Equity	48.94%	11.65%	(3)	5.70%
Total	100.00%			8.27%

Citizens' Electric Company of Lewisburg, PA

Type of Capital	Ratios(1)	Cost Rate		Weighted Cost Rate
Long-Term Debt	51.06%	5.47%	(2)	2.79%
Common Equity	48.94%	11.65%	(3)	5.70%
Total	100.00%			8.49%

Wellsboro Electric Company

Type of Capital	Ratios(1)	Cost Rate		Weighted Cost Rate
Long-Term Debt	51.06%	4.85%	(2)	2.48%
Common Equity	48.94%	11.65%	(3)	5.70%
Total	100.00%			8.18%

Notes:
(1) Capital structure based on 2024 capital structure maintained by the Companies' Parent, C&T Enterprises.
(2) Company-provided
(3) From page 1 of Exhibit__(DWD-1), Schedule DWD-1.

Capital Structure Based upon Total Permanent Capital for the
Proxy Group of Seven Natural Gas Distribution Companies
2019 - 2023, Inclusive

	2023	2022	2021	2020	2019	5 YEAR AVERAGE
Atmos Energy Corporation						
Long-Term Debt	37.62 %	37.96 %	39.35 %	40.02 %	38.03 %	38.60 %
Preferred Stock	0.00	0.00	0.00	0.00	0.00	0.00
Common Equity	62.38	62.04	60.65	59.98	61.97	61.40
Total Capital	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %
New Jersey Resources Corporation						
Long-Term Debt	59.16 %	58.49 %	57.81 %	55.35 %	50.11 %	56.18 %
Preferred Stock	0.00	0.00	0.00	0.00	0.00	0.00
Common Equity	40.84	41.51	42.19	44.65	49.89	43.82
Total Capital	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %
NiSource Inc.						
Long-Term Debt	57.26 %	55.77 %	57.09 %	61.64 %	56.79 %	57.71 %
Preferred Stock	2.51	9.03	9.55	5.87	6.35	6.66
Common Equity	40.23	35.20	33.36	32.49	36.86	35.63
Total Capital	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %
Northwest Natural Holding Company						
Long-Term Debt	55.11 %	53.21 %	52.12 %	51.81 %	50.43 %	52.54 %
Preferred Stock	0.00	0.00	0.00	0.00	0.00	0.00
Common Equity	44.89	46.79	47.88	48.19	49.57	47.46
Total Capital	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %
ONE Gas, Inc.						
Long-Term Debt	44.05 %	42.10 %	41.74 %	41.76 %	37.65 %	41.46 %
Preferred Stock	0.00	0.00	0.00	0.00	0.00	0.00
Common Equity	55.95	57.90	58.26	58.24	62.35	58.54
Total Capital	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %
Southwest Gas Holdings, Inc.						
Long-Term Debt	58.43 %	59.25 %	59.90 %	50.90 %	49.58 %	55.61 %
Preferred Stock	0.00	0.00	0.00	0.00	0.00	0.00
Common Equity	41.57	40.75	40.10	49.10	50.42	44.39
Total Capital	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %
Spire Inc.						
Long-Term Debt	54.01 %	51.42 %	52.98 %	49.62 %	45.49 %	50.70 %
Preferred Stock	3.53	3.84	4.28	4.83	5.19	4.34
Common Equity	42.46	44.74	42.74	45.55	49.32	44.96
Total Capital	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %
Proxy Group of Seven Natural Gas Distribution Companies						
Long-Term Debt	52.23 %	51.17 %	51.57 %	50.16 %	46.87 %	50.40 %
Preferred Stock	0.87	1.84	1.98	1.53	1.65	1.57
Common Equity	46.90	46.99	46.45	48.31	51.48	48.03
Total Capital	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %

Source of Information
Annual Forms 10-K

Capital Structure Based upon Total Permanent Capital for the
Proxy Group of Fifteen Electric Companies
2019 - 2023, Inclusive

	2023	2022	2021	2020	2019	5 YEAR AVERAGE
Alliant Energy Corporation						
Long-Term Debt	57.14 %	56.27 %	55.16 %	53.51 %	53.39 %	55.09 %
Preferred Stock	0.00	0.00	0.00	1.58	1.72	0.66
Common Equity	42.86	43.73	44.84	44.91	44.89	44.25
Total Capital	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %
Ameren Corporation						
Long-Term Debt	58.18 %	56.87 %	57.07 %	54.97 %	53.29 %	56.08 %
Preferred Stock	0.47	0.52	0.56	0.70	0.81	0.61
Common Equity	41.35	42.61	42.37	44.33	45.90	43.31
Total Capital	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %
American Electric Power Corporation						
Long-Term Debt	61.39 %	59.85 %	59.86 %	60.19 %	57.30 %	59.72 %
Preferred Stock	0.00	0.00	0.00	0.00	0.00	0.00
Common Equity	38.61	40.15	40.14	39.81	42.70	40.28
Total Capital	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %
Duke Energy Corporation						
Long-Term Debt	60.51 %	59.08 %	56.43 %	55.52 %	55.39 %	57.38 %
Preferred Stock	1.58	1.63	1.73	1.82	1.87	1.73
Common Equity	37.91	39.29	41.84	42.66	42.74	40.89
Total Capital	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %
Edison International						
Long-Term Debt	66.99 %	65.60 %	61.49 %	56.44 %	54.21 %	60.95 %
Preferred Stock	4.95	4.21	4.63	5.19	6.48	5.09
Common Equity	28.06	30.19	33.88	38.37	39.31	33.96
Total Capital	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %
Entergy Corporation						
Long-Term Debt	62.66 %	66.13 %	68.58 %	66.68 %	63.04 %	65.42 %
Preferred Stock	0.85	0.81	0.58	0.76	0.90	0.78
Common Equity	36.49	33.06	30.84	32.56	36.06	33.80
Total Capital	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %
Evergy, Inc.						
Long-Term Debt	55.09 %	52.17 %	51.17 %	52.48 %	51.77 %	52.54 %
Preferred Stock	0.00	0.00	0.00	0.00	0.00	0.00
Common Equity	44.91	47.83	48.83	47.52	48.23	47.46
Total Capital	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %
IDACORP, Inc.						
Long-Term Debt	49.29 %	43.87 %	42.85 %	43.86 %	42.70 %	44.51 %
Preferred Stock	0.00	0.00	0.00	0.00	0.00	0.00
Common Equity	50.71	56.13	57.15	56.14	57.30	55.49
Total Capital	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %

Capital Structure Based upon Total Permanent Capital for the
Proxy Group of Fifteen Electric Companies
2019 - 2023, Inclusive

	2023	2022	2021	2020	2019	5 YEAR AVERAGE
North Western Corporation						
Long-Term Debt	49.99 %	49.56 %	52.09 %	52.72 %	52.27 %	51.33 %
Preferred Stock	0.00	0.00	0.00	0.00	0.00	0.00
Common Equity	50.01	50.44	47.91	47.28	47.73	48.67
Total Capital	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %
OGE Energy Corporation						
Long-Term Debt	49.03 %	50.75 %	52.57 %	49.04 %	43.56 %	48.99 %
Preferred Stock	0.00	0.00	0.00	0.00	0.00	0.00
Common Equity	50.97	49.25	47.43	50.96	56.44	51.01
Total Capital	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %
Pinnacle West Capital Corporation						
Long-Term Debt	57.67 %	56.30 %	54.46 %	52.85 %	50.91 %	54.44 %
Preferred Stock	0.00	0.00	0.00	0.00	0.00	0.00
Common Equity	42.33	43.70	45.54	47.15	49.09	45.56
Total Capital	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %
Portland General Electric Company						
Long-Term Debt	54.56 %	56.75 %	54.82 %	53.83 %	50.06 %	54.00 %
Preferred Stock	0.00	0.00	0.00	0.00	0.00	0.00
Common Equity	45.44	43.25	45.18	46.17	49.94	46.00
Total Capital	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %
Southern Company						
Long-Term Debt	65.50 %	64.37 %	64.99 %	63.22 %	61.70 %	63.96 %
Preferred Stock	0.00	0.00	0.36	0.38	0.40	0.23
Common Equity	34.50	35.63	34.65	36.40	37.90	35.81
Total Capital	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %
TXNM Energy, Inc.						
Long-Term Debt	65.72 %	64.92 %	62.92 %	61.52 %	64.02 %	63.82 %
Preferred Stock	0.17	0.18	0.20	0.22	0.25	0.20
Common Equity	34.11	34.90	36.88	38.26	35.73	35.98
Total Capital	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %
Xcel Energy Inc.						
Long-Term Debt	59.11 %	58.97 %	58.91 %	57.93 %	57.77 %	58.54 %
Preferred Stock	0.00	0.00	0.00	0.00	0.00	0.00
Common Equity	40.89	41.03	41.09	42.07	42.23	41.46
Total Capital	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %
Proxy Group of Fifteen Electric Companies						
Long-Term Debt	58.19 %	57.43 %	56.89 %	55.65 %	54.09 %	56.45 %
Preferred Stock	0.53	0.49	0.54	0.71	0.83	0.62
Common Equity	41.28	42.08	42.57	43.64	45.08	42.93
Total Capital	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %

Source of Information
Annual Forms 10-K

Citizens' Statement No. 3
Wellsboro Statement No. 3
Valley Statement No. 3

BEFORE
THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	**:**		
	:		
v.	**:**	**Docket Nos.**	**R-2025-_____**
	:		**R-2025-_____**
Citizens' Electric Company of Lewisburg, PA	**:**		**R-2025-_____**
Wellsboro Electric Company	**:**		
and Valley Energy, Inc.	**:**		

DIRECT TESTIMONY

AND EXHIBITS

OF

MELISSA SULLIVAN

ON BEHALF OF

CITIZENS' ELECTRIC COMPANY OF LEWISBURG, PA
WELLSBORO ELECTRIC COMPANY
AND
VALLEY ENERGY, INC.

APRIL 30, 2025

BEFORE
THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	**:**		
	:		
v.	**:**	**Docket Nos.**	**R-2025**
	:		**R-2025**
Citizens' Electric Company of Lewisburg, PA	**:**		**R-2025**
Wellsboro Electric Company	**:**		
and Valley Energy, Inc.	**:**		

DIRECT TESTIMONY OF MELISSA SULLIVAN
ON BEHALF OF CITIZENS' ELECTRIC COMPANY OF LEWISBURG, PA,
WELLSBORO ELECTRIC COMPANY, AND VALLEY ENERGY, INC.

Q. Please state your name and business address.

A. My name is Melissa Sullivan and my business address is 33 Austin Street, Wellsboro, Pennsylvania.

Q. By whom are you employed?

A. I am employed by C&T Enterprises, Inc. ("C&T"), as the Chief Financial Officer ("CFO").

Q. What are your duties in that capacity?

A. As CFO, I have a number of duties, including: administering C&T's financial activities; reporting to C&T's Chief Executive Officers and Board of Directors regarding C&T's financial condition and making recommendations when required; providing accounting support to the affiliated companies; arranging long-term and short-term financing for C&T's affiliates; reviewing the operating companies' monthly financial statements and consolidating the financial statements quarterly for C&T's officers, directors and lending institutions review; assisting each accounting department with preliminary and year-end audits; reviewing and consolidating annual budgets and supplying the operating companies with projections for shared services and long-term and short-term debt service projections;

and attending at least one Board of Directors meeting for each operating company to review audited financials and provide an update on C&T. In addition, I have responsibility for the oversight of regulatory activities of C&T's affiliates: Citizens' Electric Company of Lewisburg, PA ("Citizens'"); Wellsboro Electric Company ("Wellsboro"); and Valley Energy, Inc. ("Valley") (collectively, "Companies"). Regulatory activities include annual Pennsylvania Public Utility Commission ("PUC" or "Commission") reporting, securities certificate filings, rate filings, Public Utility Realty Tax Act ("PURTA") filings, State Tax Adjustment Surcharge ("STAS") filings and Generation Supply Service Rate ("GSSR")/Gas Cost Rate ("GCR") filings and GSSR/GCR audits.

Q. Please describe your employment and educational background.

A. I have a Bachelor of Science degree in Business Administration and Industrial Relations (Human Resources) from Clarion University of Pennsylvania as well as a Master of Science degree in Business Leadership from Wilkes University. I began my career as Business Manager at Galeton Area School District in 2007 and remained there until 2013. In 2013, I accepted a position at Mansfield University of Pennsylvania as Human Resources Manager working directly with the Director of Human Resources and other top officers. In 2014, due to cutbacks at the University, I began serving as Director of Human Resources at SMC Powder Metallurgy, where I remained until taking the position as Chief Financial Officer at C&T Enterprises, Inc. in 2018.

Q. What are your responsibilities with respect to this filing?

A. I am responsible for coordinating the internal and external resources for this case, including legal, consulting, auditing and company support.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to explain C&T's roles and procedures as the management services company, and to discuss the history and circumstances surrounding C&T's acquisition of the three operating companies that are seeking rate relief (Citizens', Wellsboro, and Valley). I will also discuss affiliate transactions, financing and tax issues.

Q. Did you provide information to other witnesses to prepare their testimony for this proceeding?

A. Yes. Mr. Gorman, Mr. D'Ascendis and the Citizens', Wellsboro and Valley witnesses rely upon certain information that I provided.

HISTORY OF C&T AND ACQUISITIONS

Q. Please explain the relationship between C&T and the affiliates.

A. C&T is a for-profit subsidiary of Claverack Rural Electric Cooperative ("Claverack") and Tri-Country Rural Electric Cooperative ("Tri-County"). C&T was formed in 1998 to facilitate the purchase of Citizens'. C&T now owns all of the stock of Citizens', Wellsboro and Valley. Charts showing the current corporate family structures are attached as Exhibit __ (MS-1). Also included in Exhibit __ (MS-1) is a description of each entity within the C&T family.

Q. Could you please provide a brief history of each of the affiliate acquisitions by C&T?

A. As noted above, C&T was originally formed by Tri-County and Claverack in 1998 to acquire Citizens'. On February 8, 1999, C&T completed a stock purchase acquiring approximately 99% of Citizens' stock. Subsequently, C&T acquired the remaining shares. On March 10, 1994, Tri-County formed Wilderness Area Utilities, Inc. ("Wilderness"), to acquire Wellsboro. On January 4, 1995, Wilderness completed a stock purchase acquiring

100% of Wellsboro. On January 1, 2005, Tri-County transferred 100% ownership of its common stock in Wilderness to C&T. Wilderness then transferred 100% of its stock in Wellsboro to C&T and Wilderness was subsequently inactivated.

C&T formed Valley on October 17, 2000, to facilitate the purchase of the assets of Valley Cities Gas and Waverly Gas Service from NUI Corporation. On November 7, 2002, the transaction was completed and Valley assumed ownership of the assets and began operation. C&T's most recent consolidated financial statements for the years ending 2023 and 2024 are included in Volume III as Joint Confidential Exhibit 1.

Q. Do you have any comments on the capital structures that exist for each operating company?

A. Yes. Attached as Exhibit__(MS-2) is a comparison of the capital structures for Citizens', Wellsboro, Valley and C&T (consolidated) for the HTY, FTY and FPFTY. C&T's three PUC-regulated subsidiaries have different capital structures, due to the historic financial practices of each particular subsidiary prior to C&T's acquisition, the amount of debt that has been incurred since acquisition to fund system improvements, and/or the deal structure for the acquisition. All three C&T subsidiaries have rate cases pending before the Commission. As the shareholder for all three utilities, C&T believes that it is fair and appropriate to adopt a reasonable hypothetical capital structure in each case to ensure that the interests of shareholders and ratepayers are balanced with respect to all three of its PUC-regulated subsidiaries. Mr. D'Ascendis' and Mr. Kucan's testimony explains the hypothetical capital structure that is appropriate for Citizens', Wellsboro, and Valley.

C&T SERVICES PROVIDED TO CITIZENS', WELLSBORO, AND VALLEY

Q. Please describe the services that C&T provides the affiliates.

A. In addition to being the parent holding company, C&T currently provides various management services to its affiliates. These services include shared services such as legal/regulatory; human resources and payroll; communications; call center; information technology; cyber-security; and safety oversight.

Q. Are there Affiliated Interest Agreements that address the services provided among the C&T entities?

A. Yes. There is an Affiliated Interest Agreement ("AIA") that was executed by all of the C&T entities (including the cooperatives) in 2022. A copy of the AIA is attached as Exhibit__(MS-3). C&T has a more detailed Contract for Services with each subsidiary that implements the AIA. The Contracts for Services for Citizens', Wellsboro and Valley are attached as Exhibits__(MS-4) (Citizens'), __(MS-5) (Wellsboro) and __(MS-6) (Valley). Please note that the schedule containing confidential salary and overhead information for specific positions has been redacted from each of these exhibits; however, the schedules are included in Volume III of the filings as Citizens' Confidential Exhibit 1, Wellsboro Confidential Exhibit 1 and Valley Confidential Exhibit 1

Q. How does C&T determine the wages and benefits that are billed to each of the affiliates for these assigned employees?

A. The affiliates choose their employees, but the official "employer" for all non-union employees is C&T. The wages and benefits billed to Citizens', Wellsboro and Valley for the C&T employees are a direct assignment of the salaries and benefits provided to the

particular employees by C&T. This applies only to non-union positions. Wellsboro's linemen are union employees that are employed directly by Wellsboro.

With the exception of the salaries for the CEOs of Claverack, Tri-County and the three subsidiaries, which are established by the respective Boards of Directors, C&T applies its recently-updated Wage & Salary Study to determine the salaries for each of its employees. The Companies' witnesses discuss the development of the study and how it impacted their FTY and FPFTY expenses.

Each year, our human resources department monitors general wage and salary trends. After consideration of these factors, C&T's Board of Directors, upon the recommendation of the human resources department and C&T's management oversight committee, determines the annual base salary plan maintenance adjustment to be applied to the pay rates of each employee. The CEOs of Citizens', Wellsboro and Valley are part of the oversight committee.

Based on performance, an employee may be awarded a merit increase or bonus. The CEO of the individual operating companies approve merit increases and bonuses when appropriate for their employees. Finally, a third-party consultant will be providing annual updates to the Wage & Salary Study that may result in targeted adjustments for certain positions based on the labor market for the particular position.

Q. Did you provide the Companies with an estimate of the base salary increase for the FPFTY?

A. Yes. Based on the historical increases approved by the Board of Directors, a 3% increase is a reasonable projection. The historic annual base salary plan maintenance increases for

the last five years are set forth in Joint Confidential Exhibit 2, which has been submitted with other confidential exhibits as Volume III of this filing.

Q. Please discuss the benefits costs for employees.

A. All full-time C&T employees assigned to the Companies are eligible for the benefits provided by C&T regardless of the operating company to which they are assigned. C&T negotiates with the providers for bulk benefit packages and premiums. The benefits for the C&T employees at Citizens', Wellsboro and Valley include: medical, vision, dental, short-term disability, long-term disability, pension and a 401(k) match.

Our pension plan, 401k, short-term disability insurance, and long-term disability insurance are provided through the National Rural Electric Cooperative Association ("NRECA"). We annually evaluate the options for health, dental and vision insurance with the assistance of an insurance broker. We also pursue negotiations regarding any insurance premium adjustments to request credits for longevity and other factors. C&T passes through the actual benefit costs of each employee.

Q. How did you forecast benefit costs for the FPFTY?

A. For the C&T Shared Services employees, we included a 3% increase.

Q. How has C&T historically billed the operating companies for the various employees and services provided?

A. When possible, C&T attempts to directly assign costs to the operating companies. If direct assignment is not administratively feasible, then we develop another reasonable allocation methodology consistent with the approved affiliated-interest agreements.

Wages are billed monthly based on weekly time sheets submitted by each operating company. The operating companies are billed for the direct and indirect labor expenses

for their employees. All employee benefits are arranged for and paid by C&T. The premiums for medical, prescription, vision, dental, life insurance, and contributions to the pension fund are directly assigned to the companies based on which company the employee is assigned. All other benefits are allocated monthly based on percentage of payroll.

C&T SHARED SERVICES

Q. Please provide a more detailed description of the "shared services" that the affiliates have access to from C&T.

A. The shared services provided by C&T are described in Exhibit__(MS-1) and include the following: human resources and payroll, information technology, communications, call center, controller, safety compliance, and legal/regulatory. These departments perform numerous services for the operating companies.

Human resources and payroll are responsible for employee wages and benefits. They complete bi-weekly payrolls, maintain employee personnel files, process insurance claims, counsel employees on benefits, handle job vacancies, administer evaluations and complete all payroll tax returns and other reports.

The information technology department lends support for the software and hardware used by the affiliates. They also purchase required software and hardware. They are the liaison between the operating companies and tech support of the third-party billing and accounting software companies. We also recently created an internal position for a Director of Cybersecurity, which oversees cybersecurity and network integrity. The costs for this function are allocated as a subset of the IT function costs.

Communications assists with public relations, preparing customer newsletters and other communications and coordinating press inquiries.

Customers of all entities in the C&T family can contact the Call Center after normal working hours to report outages and emergencies.

The legal/regulatory department provides corporate legal and regulatory support for C&T and its subsidiaries. This includes regulatory filings, PUC comments and working groups, assistance with various contracts (vendor and customer), regulatory and business strategy and other matters.

I have already detailed the activities of the controller's department. My assistance in these rate filings and on other regulatory and financial issues is part of the shared services that C&T provides.

Q. What are the advantages of providing the C&T affiliates with the shared services?

A. There are several advantages. First, the shared services are functions that any single entity within the C&T family may not be able to support on a stand-alone basis. For example, Citizens', Wellsboro, and Valley likely would not be able to justify having a person dedicated to human resources when viewed separately; however, when the needs of the entire C&T family are assessed, the six companies clearly can justify a person dedicated to human resources. The people filling our shared services functions have specialized knowledge on highly technical issues due, largely, to their ability to devote their entire attention to the particular topic.

Second, the personnel at C&T who provide this advice have the experience of working with three PUC-regulated entities and two non-PUC-regulated entities with a combined workforce in excess of 200 employees, more than 61,000 combined customers and combined 2021 revenues exceeding $106.5 million. These shared resources enable C&T

and its affiliates to implement more standardized solutions reflecting the "best practices" of all of the affiliated companies.

Q. How has C&T historically billed the operating companies for the shared services?

A. Salaries and benefits for shared services (except the Controller Department) are billed monthly based on a pro-rata comparison of the number of active meters and the revenues for each operating company during the previous year, as follows: 60% active meters and 40% revenue. Under the implementation plan approved by the Bureau of Audits in 2007, the expenses for the shared services and other C&T administrative expenses (other than salaries and benefits) are being allocated based on the same formula as above and billed monthly. The Controller's Department is allocated one-third to each regulated operating company. No allocation is made to Tri-County or Claverack because none of the controller's activities are performed for them.

Call Center charges are billed monthly based on a flat charge plus a nominal amount for incoming and outgoing calls attributed to the particular operating company.

Q. How do the companies allocate the costs for the Legal/Regulatory function?

A. The cost allocation for the legal/regulatory function reflects the anticipated activities for this department. Specifically, 10% of the costs of this function are classified as relating to the operation of the C&T corporation. That 10% is allocated among the member organizations using the meters/revenue allocation that is used for the other C&T Shared Support Services (except Treasury/Corporate Finance and Call Center). The remaining 90% of the Legal/Regulatory department costs are allocated 1/3, 1/3, 1/3 to Citizens', Valley and Wellsboro, like the allocation of the Treasury/Corporate Finance department costs. To appropriately account for any projects or activities done for Claverack and Tri-

County, the Legal/Regulatory department tracks the hours on those projects. Claverack and Tri-County compensate C&T for the tracked Legal/Regulatory hours, and those payments are used to offset the costs allocated to Citizens', Valley and Wellsboro.

Q. Did you compile an exhibit with historic affiliate charges between C&T and Citizens', Wellsboro and Valley?

A. Yes. Volume III includes Joint Confidential Exhibit 3 with the inter-affiliate charges by month for the last three years.

FINANCING AND OTHER BENEFITS OF C&T STRUCTURE

Q. How does the C&T relationship enhance financing options for Citizens', Wellsboro and Valley?

A. C&T's relationship with Tri-County and Claverack provides C&T access to reasonable cost financing with better terms. C&T offers this financing to the operating companies. Also, C&T has obtained reasonable premiums for Directors & Officers ("D&O"), liability, and property insurance for its electric affiliates through Federated Rural Electric Cooperative Insurance Company.[1] The parent companies (C&T, Claverack and Tri-County) also provide parental guarantees when necessary for various contracts such as Citizens' and Wellsboro's wholesale electricity supply agreements, thus reducing the operating companies' need to access independent or third-party financing for these arrangements. Citizens', Wellsboro, and Valley each have access from C&T to a $14 million short-term line of credit.

[1] Federated does not provide certain types of insurance for natural gas companies.

Q. Please describe the financing arrangements that C&T has in place for Citizens', Wellsboro, and Valley.

A. Due to its affiliation with Tri-County and Claverack, C&T is able to borrow funds for Citizens', Wellsboro's and Valley's use from the National Cooperative Services Corporation ("NCSC"). NCSC is a lending institution formed by the Cooperative Finance Corporation to address the financing needs of for-profit affiliates of rural electric cooperatives. C&T borrows funds from NCSC on behalf of Citizens', Wellsboro, and Valley. Currently, C&T has approximately $35.2 million in outstanding debt with NCSC on behalf of its subsidiaries. Citizens', Wellsboro, and Valley guarantee this debt with their assets and stock.

Q. Have you compiled a list of all outstanding loans between C&T and Citizens', Wellsboro and Valley?

A. Yes. Attached as Exhibit__(MS-7) is a table with the outstanding debt, original value, current outstanding, issuance date, maturity date and interest rate for all three affiliates.

Q. What requirements or covenants does NCSC place on C&T?

A. In addition to the standard Affirmative and Negative Covenants, NCSC requires C&T to meet certain financial ratios, such as an annual Debt Service Coverage ("DSC") ratio on a consolidated basis of not less than l.15, and an Equity Ratio. NCSC also requires quarterly financial reporting on a consolidated basis and an audited annual report for each subsidiary. By January 31 of each calendar year each subsidiary must provide an updated five-year financial plan.

Other covenants include that C&T shall not declare or make any dividend payments without the written consent of NCSC. Without the prior written consent of NCSC, C&T

shall not cause or permit any subsidiary to: (i) consolidate with, merge, or sell all or substantially all of its business or assets, to another entity or person, or (ii) acquire the assets of another business or entity. Finally, C&T must notify NCSC of any changes in its management agreements with any of its affiliates and shall submit copies of such revised agreements to NCSC.

Q. Will the requested rate relief be viewed positively by C&T's lender?

A. Yes. As discussed above, NCSC actively monitors the financial condition of C&T and its subsidiaries. Improving Citizens', Wellsboro's, and Valley's financial conditions through the requested rate relief will contribute to C&T's ability to continue meeting its loan covenants and also influence the amount of financing that NCSC may be willing to provide C&T and its subsidiaries in the future for various purposes. Finally, by ensuring that the Companies' rates provide the Companies with the opportunity to earn a fair return, the companies may be able to fund some capital improvements without incurring additional debt.

TAX MATTERS

Q. Does C&T submit a consolidated federal tax filing?

A. Yes. We submit a federal filing that consolidates C&T, Citizens', Wellsboro and Valley for tax purposes. A copy of our most recent tax filing is included in Volume III as Joint Confidential Exhibit 4. Each of the companies files a separate state income tax return.

Q. Does this complete your Direct Testimony?

A. Yes.

Citizens' Statement No. 3
Wellsboro Statement No. 3
Valley Statement No. 3

BEFORE
THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	**:**		
	:		
v.	**:**	**Docket Nos.**	**R-2025-_____**
	:		**R-2025-_____**
Citizens' Electric Company of Lewisburg, PA	**:**		**R-2025-_____**
Wellsboro Electric Company	**:**		
and Valley Energy, Inc.	**:**		

EXHIBITS

OF

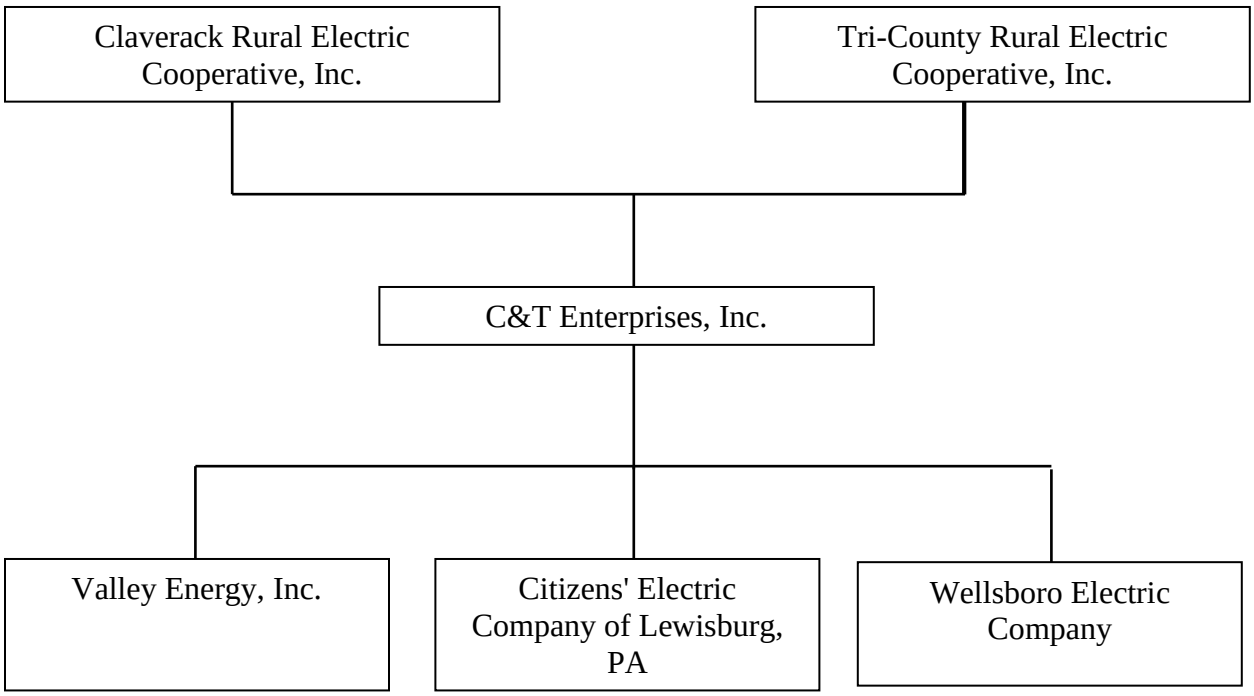
MELISSA SULLIVAN

ON BEHALF OF

DIRECT TESTIMONY OF MELISSA SULLIVAN
ON BEHALF OF CITIZENS' ELECTRIC COMPANY OF LEWISBURG, PA,
WELLSBORO ELECTRIC COMPANY, AND VALLEY ENERGY, INC.

APRIL 30, 2025

C&T ENTERPRISES, INC.
CORPORATE CHART



DESCRIPTION OF
C&T ENTERPRISES CORPORATE CHART

Citizens' Electric Company of Lewisburg, Inc.

Citizens' is an investor-owned, for-profit electric utility incorporated under the laws of Pennsylvania. Citizens' serves approximately 7,150 customers in and around Lewisburg, Pennsylvania, in a 55 square mile territory in Northumberland and Union Counties. Approximately eighty-three percent (83%) of Citizens' customers are residential, with the remaining seventeen percent (17%) of customers being commercial, small industrial, or lighting customers. Citizens' is subject to regulation by the Pennsylvania Public Utility Commission ("PUC" or "Commission").

Claverack Rural Electric Cooperative, Inc.

Claverack is a member-owned rural electric cooperative incorporated under the Pennsylvania Electric Cooperative Corporation Act of 1937 providing service to approximately 19,100 meters in an eight-county region in northeastern Pennsylvania. Its service area is approximately 1,820 square miles in area. Claverack's service area includes all or parts of the following counties: Bradford, Lackawanna, Luzerne, Lycoming, Sullivan, Susquehanna, Tioga and Wyoming. Approximately ninety (90%) of Claverack's customers are residential or seasonal customers.

C&T Enterprises, Inc.

C&T is a Pennsylvania business corporation originally established for the acquisition of Citizens' stock and generally for the management of Citizens' electric utility operations. C&T currently functions as a public utility holding company and a management services company for the Group Members.

Tri-County Rural Electric Cooperative, Inc.

Tri-County is a member-owned rural electric cooperative incorporated under the Pennsylvania Electric Cooperative Corporation Act of 1937. Tri-County provides electric service to approximately 19,600 meters in the following counties in northcentral Pennsylvania: Bradford, Cameron, Clinton, Lycoming, McKeon, Potter and Tioga. Tri-County's service territory is

approximately 4,484 square miles in area. The Rural Utility Service, Office of the United States Department of Agriculture, provides administrative oversight of Tri-County's operations.

Valley Energy, Inc.

Valley is a for-profit, investor-owned public utility incorporated under the laws of Pennsylvania. Valley has two operating divisions: VE-PA and VE-NY. VE-PA is engaged in the business of supplying and distributing natural gas to approximately 6,500 residential customers, 850 commercial and industrial customers, and 73 transportation customers. VE-PA's service territory is in and around Sayre, Pennsylvania, in northcentral Pennsylvania. VE-PA is subject to regulation by the Commission.

VE-NY is a for-profit, investor-owned public utility incorporated under the laws of Pennsylvania. VE-NY is engaged in the business of supplying and distributing natural gas to approximately 1,800 residential and 200 commercial and industrial customers. VE-NY's service area is in and around Waverly, New York. VE-NY is subject to regulation by the New York Public Service Commission.

Wellsboro Electric Company

Wellsboro is a for-profit, investor owned utility rendering electric utility service in the Borough of Wellsboro, Pennsylvania and surrounding communities. Wellsboro serves approximately 6,400 customers, of which approximately eighty percent (80%) are residential and nineteen percent (20%) are commercial or industrial. Wellsboro is regulated by the PUC.

C&T ENTERPRISES CONSOLIDATED COMPANIES
CALCULATION OF CAPITAL STRUCTURE AND RELATED RATIOS
2022 - 2026

2022	CITIZENS ELECTRIC CO.		WELLSBORO ELECTRIC CO.		VALLEY ENERGY (PA)		C&T CONSOLIDATED (Elimination Entries Reflected)	
	Total Company Actual Amount Outstanding (Thousands of Dollars)	Ratios	Total Company Actual Amount Outstanding (Thousands of Dollars)	Ratios	Total Company Actual Amount Outstanding (Thousands of Dollars)	Ratios	Total Company Actual Amount Outstanding (Thousands of Dollars)	Ratios
Total Debt	$ 2,359	14.90%	$ 14,294	74.93%	$ 6,477	32.51%	$ 31,932	50.64%
Total Preferred / Preference Stock	$ -	0.00%	$ 130	0.68%	$ -	0.00%	$ -	0.00%
Total Common Equity	$ 13,461	85.10%	$ 4,654	24.39%	$ 14,907	67.49%	$ 31,124	49.36%
Total Capital	$ 15,820	100.00%	$ 19,078	100.00%	$ 21,384	100.00%	$ 63,056	100.00%

2023	CITIZENS ELECTRIC CO.		WELLSBORO ELECTRIC CO.		VALLEY ENERGY (PA)		C&T CONSOLIDATED (Elimination Entries Reflected)	
	Total Company Actual Amount Outstanding (Thousands of Dollars)	Ratios	Total Company Actual Amount Outstanding (Thousands of Dollars)	Ratios	Total Company Actual Amount Outstanding (Thousands of Dollars)	Ratios	Total Company Actual Amount Outstanding (Thousands of Dollars)	Ratios
Total Debt	$ 2,108	13.34%	$ 16,543	75.35%	$ 5,709	28.77%	$ 32,835	50.26%
Total Preferred / Preference Stock	$ -	0.00%	$ 126	0.59%	$ -	0.00%	$ -	0.00%
Total Common Equity	$ 13,697	86.66%	$ 5,282	24.06%	$ 15,655	71.23%	$ 32,489	49.74%
Total Capital	$ 15,805	100.00%	$ 21,951	100.00%	$ 21,364	100.00%	$ 65,324	100.00%

2024	CITIZENS ELECTRIC CO.		WELLSBORO ELECTRIC CO.		VALLEY ENERGY (PA)		C&T CONSOLIDATED (Elimination Entries Reflected)	
	Total Company Actual Amount Outstanding (Thousands of Dollars)	Ratios	Total Company Actual Amount Outstanding (Thousands of Dollars)	Ratios	Total Company Actual Amount Outstanding (Thousands of Dollars)	Ratios	Total Company Actual Amount Outstanding (Thousands of Dollars)	Ratios
Total Debt	$ 5,160	26.96%	$ 20,822	79.84%	$ 7,785	33.91%	$ 41,624	55.21%
Total Preferred / Preference Stock	$ -	0.00%	$ 126	0.48%	$ -	0.00%	$ -	0.00%
Total Common Equity	$ 13,983	73.04%	$ 5,132	19.68%	$ 16,483	66.09%	$ 33,763	44.79%
Total Capital	$ 19,143	100.00%	$ 26,080	100.00%	$ 24,268	100.00%	$ 75,387	100.00%

2025	CITIZENS ELECTRIC CO.		WELLSBORO ELECTRIC CO.		VALLEY ENERGY (PA)		C&T CONSOLIDATED (Elimination Entries Reflected)	
	Total Company Actual Amount Outstanding (Thousands of Dollars)	Ratios	Total Company Actual Amount Outstanding (Thousands of Dollars)	Ratios	Total Company Actual Amount Outstanding (Thousands of Dollars)	Ratios	Total Company Actual Amount Outstanding (Thousands of Dollars)	Ratios
Total Debt	$ 4,897	26.05%	$ 19,351	80.51%	$ 7,522	33.39%	$ 39,009	54.98%
Total Preferred / Preference Stock	$ -	0.00%	$ 126	0.52%	$ -	0.00%	$ -	0.00%
Total Common Equity	$ 13,903	73.95%	$ 4,558	18.96%	$ 15,009	66.61%	$ 31,944	45.02%
Total Capital	$ 18,800	100.00%	$ 24,035	100.00%	$ 22,531	100.00%	$ 70,953	100.00%

2026	CITIZENS ELECTRIC CO.		WELLSBORO ELECTRIC CO.		VALLEY ENERGY (PA)		C&T CONSOLIDATED (Elimination Entries Reflected)	
	Total Company Actual Amount Outstanding (Thousands of Dollars)	Ratios	Total Company Actual Amount Outstanding (Thousands of Dollars)	Ratios	Total Company Actual Amount Outstanding (Thousands of Dollars)	Ratios	Total Company Actual Amount Outstanding (Thousands of Dollars)	Ratios
Total Debt	$ 4,634	24.34%	$ 18,915	77.33%	$ 9,230	36.35%	$ 35,570	51.92%
Total Preferred / Preference Stock	$ -	0.00%	$ 126	0.52%	$ -	0.00%	$ -	0.00%
Total Common Equity	$ 14,401	75.66%	$ 5,420	22.16%	$ 16,162	63.65%	$ 32,943	48.08%
Total Capital	$ 19,035	100.00%	$ 24,461	100.00%	$ 25,392	100.00%	$ 68,513	100.00%

AFFILIATED INTEREST AGREEMENT

Agreement dated as of this 31st day of May, 2022, between Citizens' Electric Company of Lewisburg, PA ("Citizens'), Wellsboro Electric Company ("WECO"), Valley Energy, Inc. – Pennsylvania Division ("VE-PA"), Valley Energy, Inc. – New York Division ("VE-NY"), C&T Enterprises, Inc. ("C&T"), Tri-County Rural Electric Cooperative, Inc. ("Tri-County"), and Claverack Rural Electric Cooperative, Inc. ("Claverack"), which are collectively referred to herein as the "Group" or individually as "Member".

Citizens', WECO and VE-PA are public utilities regulated by the Pennsylvania Public Utility Commission ("PUC-regulated Members"). VE-NY is a public utility regulated by the New York Public Service Commission. The other Members noted above do not provide public utility services that are subject to the jurisdiction of a state regulatory agency. A description of each Member is included as Attachment A. A corporate organization chart is included as Attachment B.

From time to time, Citizens', WECO, VE-PA, VE-NY, C&T, Claverack, and Tri-County may provide equipment for use by other Members and/or furnish services consistent with the categories specified herein and have agreed to the amounts to be paid.

Now, therefore, in consideration of the mutual covenants herein, the parties hereto agree as follows:

ARTICLE I

SERVICES PROVIDED AMONG GROUP MEMBERS ON TEMPORARY BASIS

Members of the Group may furnish personnel, equipment, and other resources on temporary basis to other Members of the Group. These services include C&T Shared Support

Services: Treasury/Corporate Finance, Human Resources, Information Technology, , Corporate Communication, Safety and Compliance, Call Center, Legal/Regulatory; and Group Member Services: Management, Construction, and Engineering. The rates and charges for such services shall be the lower of market or actual cost.

ARTICLE II

PAYMENT OF CHARGES FOR GROUP MEMBER SERVICES

A. Services. A Member of the Group receiving services hereunder shall pay to the Member providing said services the actual cost thereof or a market rate, whichever is less. Payment for services rendered by personnel for another Member or in common with another Member shall be based on actual time spent by such personnel as reflected in their daily time sheets or other reasonable means of determination, and will include the actual wages, fringe benefits and overheads applicable to such personnel, including the employee's wage and salary (including base pay, overtime, vacation, holiday, sick, personal days and bereavement), benefits (life insurance, pension, medical, prescription, vision, and dental) and overhead (FICA/Medicare, FUTA/SUTA, matching 401(k) contributions, and workers compensation). Attachment C sets forth the elements of Benefits and Overhead, and the source of the charges for each. Costs incurred in connection with services rendered which can be readily identified and related exclusively to a Member shall be charged directly to that Member. Costs incurred by C&T in rendering services in shared support services that cannot be identified to a specific Member shall be allocated among the appropriate Members using allocation methods specified in Article III.

B. Equipment. A Member of the Group using equipment hereunder shall pay to the Member providing the equipment all readily identifiable costs related to use of that equipment. Costs related to jointly-used equipment shall be allocated to Members based on the relative proportionate use of the equipment and/or other allocation methods generally accepted for ratemaking and financial reporting purposes.

ARTICLE III

C&T SHARED SUPPORT SERVICES

A. C&T shall provide to the Members of the Group certain shared support services, including:

1. Treasury/Corporate Finance - advice and assistance on accounting, financial, regulatory support, management of long-term and short-term financing arrangements.

2. Human Resources - responsibility for employee wages and benefits, completing bi-weekly payrolls, maintaining employee personnel files, processing insurance claims, counseling employees on benefits, handling job vacancies, administering evaluations and completing all payroll tax returns and other reports.

3. Information Technology - support for the network infrastructure, cybersecurity, software and hardware used by the Members, including the purchase of required networking equipment, security appliances, software and hardware, and acting as the liaison between the Members and third-party technology companies.

4. Corporate Communications - provides public relations support and assists with press inquiries.

5. Safety and Compliance - assists Members with understanding and fulfilling safety and compliance issues, including compliance with state and federal workplace safety regulations and requirements.

6. Call Center - after hours call center to handle inquiries from Members' customers.

7. Legal/Regulatory – advice and assistance on legal and regulatory issues, including contracts, rates, ratemaking, tariffs, commission proceedings, legislative proposals, regulatory business strategy and similar issues.

B. To the extent a cost incurred by C&T to perform the shared support services can be directly allocated to a particular Member of the Group, it will be billed in accordance with the procedures set forth in Article V below.

C. The labor, overhead, benefits, expenses, administrative expenses and other costs of C&T's provision shared support services that cannot be directly assigned shall be allocated as follows:

1. Treasury/Corporate Finance: The costs of the Corporate Finance function shall be allocated equally among Citizens', WECO and VE-PA/VE-NY (i.e., 1/3 to each). For purposes of this allocation, VE-PA/VE-NY will be classified as a single Member.

2. Call Center: The costs of the Call Center will be allocated to the Members based on a combination of a fixed monthly base fee and usage of the Call Center services during the month. On a calendar year basis, C&T will

compare the revenues collected for the Call Center and the expenses of the Call Center. If the revenues exceed the expenses, C&T will refund the excess amount to the Members pro rata based on the percentage of calls handled for each Member in comparison to the total calls handled for the group. If the expenses exceed the revenues, C&T will collect the excess amount from the Members pro rata based on the percentage of calls handled for each Member in comparison to the total calls handled for the group.

3. Legal/Regulatory: The costs of the Legal/Regulatory function shall be allocated: (A) 10% to C&T to reflect corporate administration activities (which shall then be subject to the apportionment as reflected in Section III(C)(4) below); and (B) 90% to the regulated utilities (Citizens', WECO and VE-PA/VE-NY), to be shared 1/3, 1/3 and 1/3. For purposes of this allocation, VE-PA/VE-NY will be classified as a single Member. The Legal/Regulatory department shall track and report hours that are spent on projects for Tri-County or Claverack, which shall be billed for such work by C&T as set forth in Article II(a). Citizens', WECO and VE-PA/VE-NY shall receive credits for any hours spent by the Legal/Regulatory department on projects for Tri-County or Claverack.

4. Other Shared Support Services: The costs for the other shared support services will be allocated based on each Member's pro-rata share of the total meters and total revenues. Specifically, 60% of the costs will be allocated based on active meters and 40% of the costs will be allocated based on

annual revenues. The results of this allocation shall be updated each calendar year.

5. Other Expenses: Any expenses of C&T that are not addressed through the allocations discussed in sections 1, 2, 3 and 4 above shall be billed to the Group Members based on the allocation formula specified in section 4 above.

ARTICLE IV

GROUP MEMBER SERVICES PROVIDED ON AS NEEDED BASIS

Members of the Group may provide the following services to other Members on an as needed basis:

A. Management - advice and guidance on business operations and projects such as additions or improvement to property, plant or equipment.

B. Construction - personnel to assist in construction or service restoration activities.

C. Engineering - advice on the design and implementation of utility system extensions and enhancements, including the connection of customer generation.

ARTICLE V

BILLING PRACTICES

As soon as practical after the 15th of each month, or such other period as may be agreed upon by the respective Members of the Group, a billing or accounting shall be rendered for all amounts due for services and expenses for such period, computed pursuant to this Agreement. These bills shall be in sufficient detail to show separately the charge for each class of service

rendered and any intercompany allocations hereunder. Each Member shall keep its books and records available at all times for inspection by regulatory bodies having jurisdiction over them and shall furnish, upon request, any and all information required with respect to services rendered, the costs thereof and the allocation of such costs among the parties to this Agreement.

ARTICLE VI

FINANCING

A Member may, from time to time, loan funds to another Member(s) of the Group. Short-term loans will be evidenced by promissory notes bearing interest at applicable market rates. Long-term loans will be evidenced by promissory notes bearing interest at applicable market rates or the equivalent cost of financing by the lending Member and containing repayment terms consistent with reasonable market terms or those assumed by the lending Member. All long term loans to PUC-regulated Members made pursuant to this Article shall be subject to the applicable provisions of the Public Utility Code, including but not limited to, Chapter 19 Securities and Obligations.

ARTICLE VII

CONTROLLING AGREEMENT

Until this Agreement takes effect, Citizens', C&T, Claverack, Tri-County, VE-PA/VE-NY and WECO will continue to operate pursuant to the Affiliated Interest Agreement dated October 9, 2019, that was approved at Pennsylvania Public Utility Commission Docket Nos. G-2008-2020732, G-2008-2020733 and G-2008-2021399. This Agreement shall be in full force and effect as of the date approved by the Pennsylvania Public Utility Commission, and shall continue in effect through December 31, 2022 (the "initial term"). Thereafter, the Agreement shall automatically

renew for successive one-year terms unless terminated by any party hereto by giving the others sixty days written notice of termination prior to the end of the initial or renewal terms; provided, however, this Agreement shall terminate immediately with regard to any party as of the date such Member ceases to be an affiliated Member of the Group (except to the extent that compensation is still to be paid for services rendered by, or to, any Member prior to the date of such cessation of affiliation). The terms of this Agreement shall be automatically extended to the successors and assignees of the parties. This Agreement may be executed in multiple counterparts.

IN WITNESS WHEREOF, the parties have hereunto executed this Agreement as of the day and year first above written.

C&T ENTERPRISES, INC.

Date 5/19/22

By _____
Name STEVEN ALLABAUGH
Title PRESIDENT & CEO

CITIZENS' ELECTRIC COMPANY OF LEWISBURG, PA.

Date 5/31/22

By _____
Name John Kelchner
Title President & CEO

CLAVERACK RURAL ELECTRIC COOPERATIVE

Date 5/19/22

By _____
Name STEVEN ALLABAUGH
Title PRESIDENT & CEO

TRI-COUNTY RURAL ELECTRIC COOPERATIVE, INC.

Date 5/25/22

By Aaron S. Young
Name Aaron S. Young
Title President/CEO

WELLSBORO ELECTRIC COMPANY

Date 5/24/22

By Byron Farnsworth Jr
Name Byron Farnsworth Jr
Title President/CEO

VALLEY ENERGY INC., New York Division

Date 5/26/22

By E E Rogers
Name EDWARD J ROGERS
Title PRESIDENT & CEO

VALLEY ENERGY, INC., Pennsylvania Division

Date 5/26/22

By E E Rogers
Name EDWARD J ROGERS
Title PRESIDENT & CEO

Attachment "A"

AFFILIATED INTEREST AGREEMENT
OF
CITIZENS' ELECTRIC COMPANY, WELLSBORO ELECTRIC COMPANY,
VALLEY ENERGY, INC. – PENNSYLVANIA DIVISION, ET AL.

DOCKET NO. _____

DESCRIPTION OF GROUP MEMBERS

Citizens' Electric Company of Lewisburg, PA

Citizens' is an investor-owned, for-profit electric utility incorporated under the laws of Pennsylvania. Citizens' serves approximately 7,200 customers in and around Lewisburg, Pennsylvania, in a 55 square mile territory in Northumberland and Union Counties. Approximately eighty percent (80%) of Citizens' customers are residential, with the remaining twenty percent (20%) of customers being commercial and small industrial users. Citizens' is subject to regulation by the Pennsylvania Public Utility Commission.

Claverack Rural Electric Cooperative, Inc.

Claverack is a rural electric cooperative incorporated under the Pennsylvania Electric Cooperative Corporation Act of 1937 providing service to approximately 18,000 members in an eight-county region in Northeastern Pennsylvania. It's service area is approximately 1,820 square miles in area. Claverack's service area includes all or parts of the following counties: Bradford, Lackawanna, Luzerne, Lycoming, Sullivan, Susquehanna, Tioga, and Wyoming. Approximately ninety-four percent (94%) of Claverack's customers are residential or seasonal customers. The remaining six percent (6%) are commercial or small industrial customers. The Rural Utility Service, Office of the United States Department of Agriculture, provides oversight of Claverack's operations.

C&T Enterprises, Inc.

C&T is a Pennsylvania business corporation that functions as a public utility holding company, which owns all of the stock of Valley Energy, WECO, and Citizens'. C&T acts as a management services company for the Group Members.

Tri-County Rural Electric Cooperative, Inc.

Tri-County is a member-owned rural electric cooperative incorporated under the Pennsylvania Electric Cooperative Corporation Act of 1937. Tri-County provides electric service to approximately 19.500 members in the following counties in Northcentral, Pennsylvania: Bradford, Cameron, Clinton, Lycoming, McKeon, Potter, and Tioga. Tri-County's service territory is approximately 4,484 square miles in area. The Rural Utility Service, Office of the United States Department of Agriculture, provides administrative oversight of Tri-County's operations.

Valley Energy, Inc. – Pennsylvania Division

VE-PA is a for-profit, investor-owned public utility incorporated under the laws of Pennsylvania. VE-PA is engaged in the business of supplying and distributing natural gas to approximately 6,450 residential customers and 950 commercial and industrial customers. VE-PA's service territory is in and around Sayre, Pennsylvania, in Northcentral Pennsylvania. VE-PA is subject to regulation by the Pennsylvania Public Utility Commission.

Valley Energy, Inc. – New York Division

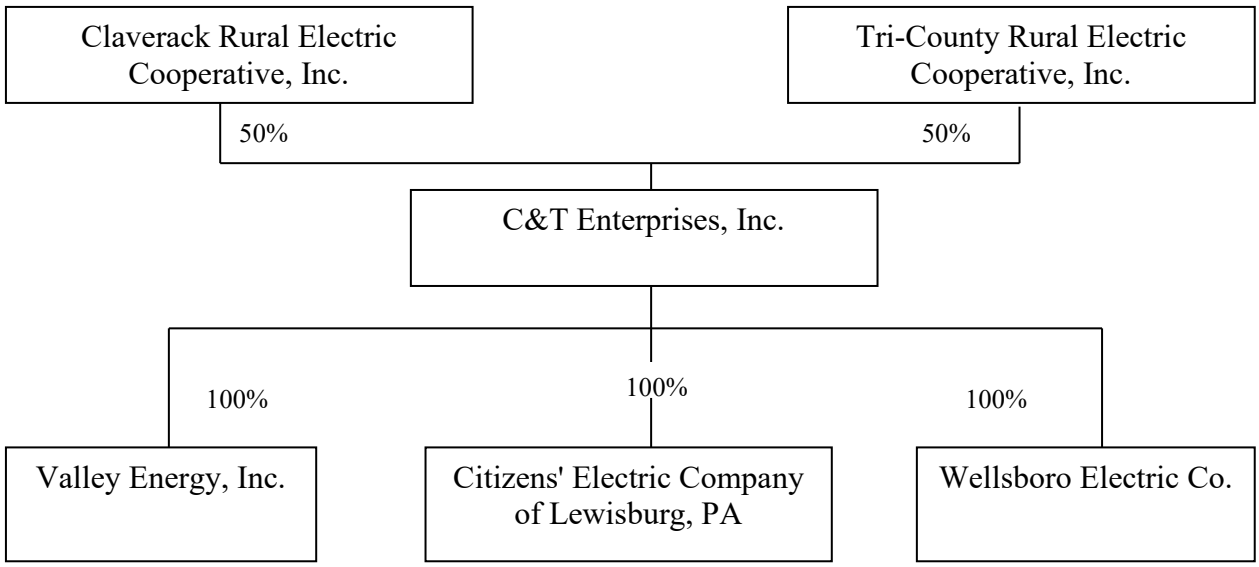
VE-NY is a for-profit, investor-owned public utility incorporated under the laws of Pennsylvania. VE-NY is engaged in the business of supplying and distributing natural gas to approximately 1,800 residential and 225 commercial and industrial customers. VE-NY's service area is in and around Waverly, New York. VE-NY is subject to regulation by the New York Public Service Commission.

Wellsboro Electric Company

WECO is a for-profit, investor-owned utility rendering electric utility service in the Borough of Wellsboro, Pennsylvania and surrounding communities. WECO serves approximately 6,400 customers, over eighty percent (80%) of which are residential and twenty percent (20%) of which are commercial or industrial. WECO is regulated by the Pennsylvania Public Utility Commission.

Attachment "B"

C & T ENTERPRISES, INC., CORPORATE CHART



Attachment "C"
Overhead and Benefits

Overhead and Benefits for C&T Employees Assigned to a Member or Providing Shared Services

Workers comp is allocated based on % of total payroll and the rate is based on the rated charged by Federated.

$$\frac{?}{\text{Total Payroll}} \times \text{Federated?} = \text{Workers Compensation}$$

NRECA R&S, medical (e.g., Blue Cross Blue Shield), dental (e.g., Delta Dental), NRECA group insurance - are all charged as billed by the provider and charged by employee to the company they are assigned to.

401k - allocated based on companies % of total payroll and the options elected by the employee under the available plan (e.g., contribution level selected by employee, current matching policy, etc.)

FICA, Medicare, FUTA, SUTA allocated based on payroll and calculated using Federal and state rates.

Overhead and Benefits—Temporary Use of Member Employees by other Members

When an assigned employee is temporarily used by another Member, the Member receiving the temporary services is billed the employee's wages plus an overhead rate of 10%.

REVISED CONTRACT FOR SERVICES

THIS CONTRACT, made and executed in duplicate this 24th day of October, 2019, by and between **C&T ENTERPRISES, INC.**, a Pennsylvania corporation, with offices at 33 Austin Street, Wellsboro, Pennsylvania, (hereinafter referred to as "C&T") and **CITIZENS' ELECTRIC COMPANY OF LEWISBURG, PA**, a Pennsylvania public utility corporation, with offices at 1775 Industrial Boulevard, Lewisburg, Pennsylvania (hereinafter referred to as "Operating Company") (each, individually, "Party" or collectively, "Parties").

WHEREAS, C&T is a public utility holding company organized for the purpose of providing management, communication, financial, technical, operational and other business-related services to its public utilities and others; and

WHEREAS, Operating Company is a for-profit, investor-owned public utility that desires to purchase services from C&T and C&T desires to sell services to Operating Company; and

WHEREAS, Operating Company and C&T are also parties to a general Affiliated Interest Agreement that is filed with the Pennsylvania Public Utility Commission among Operating Company, C&T and other entities that are classified as affiliates of Operating Company under the relevant state statutes (the "AIA")[1]; and

WHEREAS, the Parties wish to reduce their agreement to writing.

NOW THEREFORE, in consideration of the foregoing recitals of fact and the mutual benefits and obligations set forth herein, the Parties agree as follows:

1. DESCRIPTION OF SERVICES. The Parties agree to provide to each other the specific services described herein and set forth in the Addenda attached hereto, which Addenda shall be dated, signed by both C&T and Operating Company, marked alphabetically, e.g., Addendum "A," and so forth, and are incorporated by reference herein.

   1.1 PROVISION OF EMPLOYEES. C&T shall provide service to Operating Company through the assignment of individual C&T Employees to perform specific work and other activities for, and as directed by, the Operating Company. Services will be provided by the specific C&T Employees as identified in Addendum B. Such employees will be considered to be assigned to the Operating Company for purposes of the specific work and other activities.

   1.2 PROVISION AND USE OF VEHICLES, SPACE, MATERIALS AND OTHER EQUIPMENT. In addition to the services described in Paragraph 1.1 of this Contract, the Parties may provide to each other certain vehicles, space, materials and other equipment for use. The rates and charges for such vehicles, materials

[1] The Docket Number and date of approval of the most recent AIA will be set forth in Addendum A of this Contract, which will be updated as necessary.

and other equipment provided will be set forth in Addendum C to this Contract. The rates and charges for space will be set forth in Addendum D to this Contract.

1.3 OTHER SERVICES. In addition to the services described in Paragraphs 1.1 and 1.2 of this Contract, the Parties may provide other services of a nature mutually agreed on by C&T and Operating Company. C&T and Operating Company will execute additional Addenda to this Contract describing such services and specifying the rates and charges for the services. Alternatively, C&T and Operating Company may enter into additional contracts or agreements for such services.

2. RATES AND CHARGES. The rates and charges to be paid by each Party for the services provided shall be set forth on the Addenda attached hereto as provided for in Paragraph 1 of this Contract. These rates and charges shall reflect the lower of actual cost or market. Throughout the course and term of this Contract such rates and charges may be adjusted and revised for any calendar quarter period commencing on the first day of each calendar quarter, upon written notice from C&T to Operating Company not less than thirty (30) days in advance of the calendar quarter for which rates are to be changed. Operating Company's failure to notify C&T in writing of objection to the proposed rates and charges revision within thirty (30) days after receipt of proposed price revision shall be considered acceptance of such revision. In the absence of written notice from C&T to Operating Company regarding any revision of charges and rates, the rates and charges then in effect shall continue until notice is given in accordance with the foregoing schedule.

2.1 LABOR & OVERHEAD CHARGES. C&T shall calculate and bill, on a periodic basis, labor and overhead for all Employees assigned to Operating Company. Overhead charges include, but are not limited to, payroll taxes, pension, workers compensation and health insurance contributions. C&T reserves the right to estimate the monthly cost of certain benefits, subject to subsequent reconciliation. As soon as practical, any benefit adjustments will be charged or credited to the Operating Company.

2.2 SHARED SUPPORT SERVICE ALLOCATION. Consistent with the AIA, C&T will calculate and bill Operating Company for shared support services provided by C&T employees that are not assigned to Operating Company. Shared support services will include, but not be limited to, Human Resources, Payroll, Information Technology, Corporate Communications, Call, Center and Key Accounts.

3. BILLING AND PAYMENT. All rates and charges to be paid by Operating Company to C&T for services rendered to Operating Company shall be billed by C&T by invoice with sufficient detail to document and support the rates and charges set forth therein and submitted to Operating Company on or before the 15th day of each month for services rendered by C&T during the preceding month. Any amounts due from C&T to Operating Company shall be netted against the C&T charges on the monthly invoice. Payment of

such invoice shall be made in full by Operating Company to C&T on or before twenty (20) days from the date of receipt of such invoice, and in the event such invoice is not paid in full, the unpaid portion thereof shall, at C&T's option, accrue interest at the rate of one percent (1%) of the unpaid amount per month, with a partial month being counted as a full month.

3.1 ADVANCED PAYMENT. To enable C&T to meet its obligations due during the initial month of this Contract, C&T may continue to retain any Advanced Payment provided pursuant to the prior Contract for Services between the Parties. C&T may refund the Advanced Payment to the Operating Company, at any time before the termination of the Contract. To the extent not previously refunded, Operating Company shall be entitled to return of the Advanced Payment upon termination of this Contract. The amount of any Advanced Payment that remains in C&T's possession shall be set forth in Addendum E to this Contract.

3.2 ACCOUNTING LIABILITIES. In addition to any rates and charges due hereunder, Operating Company may set up a payable to C&T for amounts necessary under generally accepted accounting principles to book liabilities for future payments due, including for FAS 106 and accrued vacation obligations. C&T shall provide to Operating Company a separate invoice once per year indicating the amount of such liabilities for the year based on an actuarial estimate. Any variance between actual amounts paid by C&T during the year and the actuarial estimate provided to Operating Company shall be subject to reconciliation at the end of the year.

4. TERM. The initial term of this Contract for Services shall commence on the date of this Contract and shall continue for three years. This Contract will thereafter automatically renew for successive one-year terms unless terminated by either party by written notice provided at least sixty (60) days prior to the end of any initial or renewal term. Any such termination shall not affect any obligations undertaken or liabilities incurred by either party prior to the date of termination.

5. DESIGNATION OF OPERATING COMPANY OFFICERS. The Board of Directors of Operating Company retains full authority, power and discretion to designate the Officers for the Operating Company. To the extent the Board of the Operating Company designates a C&T Employee as an Officer of the Operating Company, the Parties shall enter into or revise Addendum B and appropriate schedules to assign the employee to the Operating Company.

6. TEMPORARY ASSIGNMENT OF C&T EMPLOYEES. Notwithstanding the categorization of the C&T Employees designated in Addendum B Schedule 1 to this Contract as being assigned to the Operating Company, C&T may, from time to time, request to use such employees to provide services to other entities. Operating Company's monthly compensation to C&T for such employee's services shall be reduced by the applicable percentage of employee's total working hours allocable to work outside Operating Company. Whenever employees assigned to Operating Company are

temporarily assigned to another operating company, their labor, overhead and expenses will be billed based the provisions of Article II, Section A and/or Article III of the AIA.

7. MANAGEMENT OF ASSIGNED C&T EMPLOYEES. Operating Company will have management authority over C&T Employees assigned to Operating Company under this Contract.

8. REQUEST FOR ADDITIONAL SERVICES. Operating Company may request, from time to time, that C&T provide additional services on a temporary or a permanent basis by C&T employees that are not permanently assigned to Operating Company. By way of example, Operating Company may request the placement of full-time staff members with IT experience on-site during a computer system conversion. Any request for additional services must be conveyed to C&T in a timely manner. To the extent such service is desired on a permanent basis, C&T and Operating Company shall mutually agree on addition of or modification to an Addendum to this Contract. If the permanently-assigned or temporarily-assigned C&T Employee is currently assigned to another entity, the Operating Company will pay a percentage of the compensation for said C&T Employee otherwise recoverable from the other entity based on the portion of total monthly working hours allocable to Operating Company or a written agreement between the two Operating Companies. To the extent such assignment is temporary and such C&T Employee is not currently assigned to another entity, C&T and Operating Company will mutually agree on appropriate compensation.

9. OVERSIGHT COMMITTEE. C&T shall form and convene an Oversight Committee to address complaints, problems or grievances that arise under this Contract or similar agreements entered into with other entities. Each such entity, including Operating Company, shall have the opportunity to designate a member of the Oversight Committee. The Oversight Committee will attempt to resolve all complaints, problems and grievances raised by the Operating Company and other represented entities. To the extent the Oversight Committee cannot resolve such issues, the issues will be submitted to a neutral arbitrator, mutually agreed to by Operating Company and C&T, for binding resolution. Such arbitration will be conducted according to the rules of the American Arbitration Association.

10. RELATIONSHIP OF THE PARTIES. The parties hereto understand and agree that C&T is to provide services under this Contract as an independent contractor to the Operating Company and not as an agent, employee, representative, or in any other manner or relationship whatsoever. At all times throughout the term hereof, C&T shall be free to and intends to contract to provide services to others. Except as stated herein nothing in this Contract shall in any way be construed to constitute C&T or any of C&T's agents or employees as the agent, employee or representative of the Operating Company.

11. CONFIDENTIALITY. All information furnished under and pursuant to this Contract shall be held by C&T and Operating Company in strict confidence and shall never be reproduced, revealed or made accessible in whole or in part, in any manner whatsoever, to any other persons unless required by law, applicable regulatory agencies (including the

Pennsylvania Public Utility Commission) or unless the Party first obtains the other Party's express and written consent; provided, however, the Party may reveal to the subject of the information that the other Party is a source of information about the subject and refer same to the Other Party for the purpose of obtaining such information and reviewing it. Any information specifically designated as "Confidential" may be viewed only by the Officers of the Party and only to the extent necessary to perform their designated duties. Each Party shall take reasonable steps to limit the public disclosure of confidential information provided hereunder.

12. INDEMNIFICATION. Operating Company shall hold C&T harmless against all liability or loss and against all claims or actions based on or arising out of damage or injury (including death) to persons or property caused by or sustained in connection with the performance of this contract or by conditions created thereby, or based on any violation of statue or regulation and the defense of any such claims or actions.

13. INSURANCE. C&T shall, at its sole cost and expense, be covered by comprehensive general liability insurance including contractual liability insurance with combined single limits of not less than One Million Dollars ($1,000,000.00), which insurance coverage and limits shall be evidenced by certificates of insurance as requested by the Operating Company and which insurance policies shall name the Operating Company as additional insured thereon.

14. WORKERS COMPENSATION. Any employees assigned to Operating Company hereunder shall at all times remain C&T Employees for workers compensation purposes. C&T will take reasonable actions with respect to such employees, including, but not limited to, retaining an appropriate amount of Workers Compensation Insurance. C&T agrees to indemnify, defend and hold harmless Operating Company for any workers compensation claim asserted by a C&T Employee.

15. HEADINGS. The description headings of the various paragraphs of this Contract are inserted for reference purposes only and do not form a part of this Contract and shall in no way affect meaning or interpretation thereof.

16. ENTIRE AGREEMENT. This Agreement constitutes and contains the entire understanding and agreement of the parties hereto and supersedes any and all prior understandings and agreements, oral or written, by, between and among the parties regarding the subject matter hereof.

17. AMENDMENTS. This Contract and the Addenda incorporated herein shall be modified and/or amended only by writing signed by both parties hereto, and shall not be effective until filed with and approved by any applicable regulatory agencies, including the Pennsylvania Public Utility Commission. The requirement for approval prior to effectiveness shall not apply to periodic changes to Addenda to update information such as the information regarding the AIA set forth in Addendum A and the employees and related costs assigned to Operating Company under Addendum B.

18. AUTHORITY. C&T and Operating Company hereby covenant and agree, each to the other, that their respective signatories have the authority to execute and bind each pursuant to the appropriate actions of the governing bodies of each. C&T also warrants that it has the authority to provide the services contemplated hereunder.

19. NOTICES. Any notices to be delivered under the terms of this Contract shall be sent by U.S. Mail certified, return receipt requested, addressed as follows;

To C&T:

C&T Enterprises, Inc.
33 Austin Street
Wellsboro, PA 16901

To Operating Company:

Citizens' Electric Company of Lewisburg, PA
1775 Industrial Boulevard
Lewisburg, PA 17837

20. FORCE MAJEURE. C&T shall use diligence to perform its obligations under this Contact, however, in the event that C&T is delayed in or prevented from performing or carrying out its obligations under this Contract by reason of an unforeseeable event or occurrence beyond reasonable control of and without the fault and negligence of C&T, including, but not limited to, acts of God, strike, flood, earthquake, storm, fire, lightning, epidemic, war, riot, civil disturbance, sabotage, acts of public enemy, explosion, change in law or applicable regulation subsequent to the date hereof and action or inaction by any federal, state or local legislative, executive, administrative, or judicial agency or body which, in any of the foregoing cases, by exercise of due foresight C&T could not reasonably have been expected to avoid, C&T shall not be liable to the Operating Company for or on account of any loss, damage, injury or expense resulting from or arising out of such delay or prevention, provided, however, that C&T shall use due diligence to remove the cause or causes thereof. The settlement of strikes and labor disturbances shall be wholly within the discretion of C&T. Economic hardship shall not constitute a Force Majeure under this Contract.

21. REGULATORY OVERSIGHT/APPROVAL. This Contract constitutes a component of the Affiliated Interest Agreement and relationship between C&T and Operating Company that is subject to oversight by the Pennsylvania Public Utility Commission ("PUC"). To the extent the PUC invalidates and/or modifies any portion of this Contract or the Affiliated Interest Agreement, either during an independent review of the agreement or in a proceeding before the Commission, and such action impacts the terms of this Contract, the parties agree to mutually negotiate in good faith modifications to this Contract consistent with the Commission's decision.

22. PRIOR AGREEMENTS. This Contract shall supersede and replace in its entirety the Contract for Services dated November 18, 1999 (as amended), between the Parties; provided, however, that the Parties shall remain liable for any obligations incurred under the prior Contract for Services.

23. SEVERABILITY. All agreements and covenants contained in this Contract are severable, and in the event any of them are held to be invalid by any competent court, this Contract will be interpreted as if the invalid agreements or covenants were not contained in this Contract.

24. ASSIGNMENT. This Contract may not be assigned, transferred or conveyed in whole or part by either party without the express written permission of the other.

25. CONSTRUCTION. This Contract shall be governed by the laws of the Commonwealth of Pennsylvania.

26. BINDING EFFECTS. The parties hereto covenant and agree that the terms, conditions and provisions of this Contract shall be binding upon themselves, their respective successors, and assigns.

IN WITNESS WHEREOF, the parties have caused this Contract to be executed and delivered as of the day and year first above written.

ATTEST:

Secretary

C&T ENTERPRISES, INC.

BY: Bobbi G Kilmer

TITLE: Co. President & CEO

ATTEST:

Secretary

CITIZENS' ELECTRIC COMPANY OF LEWISBURG, PA

BY: John A Kohler

TITLE: President/CEO

INDEX OF ADDENDA AND SCHEDULES
DATED THE 24TH DAY OF OCTOBER, 2019

Addendum A: Information regarding currently-effective Affiliated Interest Agreement among C&T companies

Addendum B: C&T Employees Assigned to Operating Company

Schedule B-1: Specific C&T Employees and Charges

Addendum C: Vehicles, Materials and Other Equipment

Schedule C-1: Specific Covered Items

Addendum D: Space

Schedule D-1: Summary of Leased Space

Addendum E: Outstanding Advanced Payment

CITIZENS' ELECTRIC COMPANY
CONTRACT FOR SERVICES
DATED THE 24th DAY OF OCTOBER, 2019
ADDENDUM A
(INFORMATION ON CURRENT AFFILIATED INTEREST AGREEMENT AMONG C&T COMPANIES)

The Pennsylvania Public Utility Commission approved the currently effective Affiliated Interest Agreement among the C&T companies on July 15, 2019, at Docket No. G-2008-2020733.

C&T ENTERPRISES, INC.

10/21/2019
Date

by: Bobby G Kilmer
President & CEO

CITIZENS' ELECTRIC COMPANY OF LEWISBURG, PA

10/24/2019
Date

by: John A Kahler
President & CEO

CITIZENS' ELECTRIC COMPANY
CONTRACT FOR SERVICES
DATED THE 24TH DAY OF OCTOBER, 2019
ADDENDUM B
(EMPLOYEES)

1. DESCRIPTION OF SERVICES.

C&T shall provide to Operating Company the services of the C&T Employees set forth on the attached listing, marked Schedule B-1. For the period during which this Addendum remains effective, the persons listed on Schedule B-1 shall be considered to be assigned to Operating Company. Schedule B-1 may be modified by mutual consent of C&T and Operating Company.

2. RATES AND CHARGES FOR SERVICES.

The rate and charge for services provided by C&T Employees to Operating Company shall be calculated monthly based on C&T's direct monthly costs related to each such employee, including salary, payroll taxes and benefits. The annual charge for each employee will be listed on Schedule B-1, which shall consequently be designated as highly confidential and handled in accordance with the confidentiality provisions in Paragraph 11 of the Contract.

3. EMPLOYEE BONUSES.

The C&T Employees listed on Schedule B-1 may, from time to time, be provided certain bonuses or other performance-based incentives. To the extent such bonuses or incentives are proposed or instituted by C&T, Operating Company shall have the right to refuse, for reasonable reasons and grounds, to compensate C&T for such bonuses or incentives. Operating Company may also request that C&T provide a bonus or other incentive to specific C&T Employees listed on Schedule B-1. Bonuses or incentives shall be passed through to and paid by Operating Company.

C&T ENTERPRISES, INC.

10/21/2019
Date

by: Bobby Kime
President & CEO

CITIZENS' ELECTRIC COMPANY

10/24/2019
Date

by: John A Kelly
President & CEO

SCHEDULE 1 TO ADDENDUM A

[redacted]

Title	Annual Charge
PRESIDENT & CEO	$ [redacted]
SENIOR DIRECTOR OF ENG & OPERATIONS	$ [redacted]
TREASURER	$ [redacted]
CREW CHIEF	$ [redacted]
CREW CHIEF	$ [redacted]
JOURNEYMAN LINE TECHNICIAN	$ [redacted]
JOURNEYMAN LINE TECHNICIAN	$ [redacted]
MANAGER OF CUSTOMER SERVICE	$ [redacted]
JOURNEYMAN LINE TECHNICIAN	$ [redacted]
JOURNEYMAN LINE TECHNICIAN	$ [redacted]
ENGINEERING TECHNICIAN	$ [redacted]
JOURNEYMAN LINE TECHNICIAN	$ [redacted]
2ND CLASS LINE TECHNICIAN	$ [redacted]
ACCOUNTING ASSISTANT	$ [redacted]
CUSTOMER SERVICE REPRESENTATIVE	$ [redacted]
APPRENTICE LINE TECHNICIAN	$ [redacted]
CUSTOMER SERVICE REPRESENTATIVE	$ [redacted]
APPRENTICE LINE TECHNICIAN	$ [redacted]
Total	$ 3,046,764

Rachel R. Hauser
President & CEO
C&T Enterprses, Inc.

Date: 2/12/2025

President & CEO
Citizens' Electric Company

Date: 2/12/25

CITIZENS' ELECTRIC COMPANY
CONTRACT FOR SERVICES
DATED THE 24th DAY OF OCTOBER, 2019
ADDENDUM C
(VEHICLES, MATERIALS AND EQUIPMENT)

4. DESCRIPTION OF SERVICES.

C&T shall provide to Operating Company (or Operating Company shall provide to C&T) the vehicles, materials and other equipment more particularly detailed and set forth on the attached listing, marked Schedule C-1 , which schedule is incorporated herein as though set forth at length. Schedule C-1 may be changed from time to time by mutual agreement of C&T and Operating Company.

2. RATES AND CHARGES FOR SERVICES.

The rates and charges for services set forth in Paragraph 1 hereof shall be calculated monthly based on the monthly fixed and variable costs related to such vehicles, material or equipment.

C&T ENTERPRISES, INC.

10/19/2019
Date

by: Bobby Kemmer
President & CEO

CITIZENS' ELECTRIC COMPANY

10/24/19
Date

by: John A Kuhlmann
President & CEO

SCHEDULE C-1 TO ADDENDUM C

1. Currently there are no vehicles, material or other equipment being provided by the affiliated companies.

C&T ENTERPRISES, INC.

10/21/2019
Date

by: Bobby J Kennedy
President & CEO

CITIZENS' ELECTRIC COMPANY

10/24/19
Date

by: John A Kehler
President & CEO

CITIZENS' ELECTRIC COMPANY
CONTRACT FOR SERVICES
DATED THE 24th DAY OF OCTOBER, 2019
ADDENDUM D
(SPACE)

1. DESCRIPTION OF SERVICES.

C&T shall provide to Operating Company (or Operating Company shall provide to C&T) the space more particularly detailed and set forth on the attached Schedules marked as D-1, D-2, D-3, etc. To the extent a formal lease agreement exists related to certain space, that agreement will also be included as a Schedule to this Addendum.

2. RATES AND CHARGES FOR SERVICES.

The rates and charges for services for space will be negotiated between the Parties.

C&T ENTERPRISES, INC.

10/21/2019
Date

by: Bobby Kelly
President & CEO

CITIZENS' ELECTRIC COMPANY

10/24/19
Date

by: John A Kelly
President & CEO

SCHEDULE D-1 TO ADDENDUM D
SUMMARY OF SPACE LEASED BETWEEN PARTIES

1. Currently there is no space leased between the parties.

C&T ENTERPRISES, INC.

10/21/2019
Date

by: _____
President & CEO

CITIZENS' ELECTRIC COMPANY

10/24/19
Date

by: _____
President & CEO

CITIZENS' ELECTRIC COMPANY
CONTRACT FOR SERVICES
DATED THE 24th DAY OF OCTOBER, 2019
ADDENDUM E
(ADVANCED PAYMENT)

Pursuant to Paragraph 3.1 of the Contract, C&T currently holds an Advanced Payment from Operating Company of $90,700.

C&T ENTERPRISES, INC.

10/21/2019
Date

by: Bobbi A Kilmer
President & CEO

CITIZENS' ELECTRIC COMPANY

10/24/19
Date

by: Joh A Kell
President & CEO

REVISED CONTRACT FOR SERVICES

THIS CONTRACT, made and executed in duplicate this 6th day of October, 2010, by and between **C&T ENTERPRISES, INC.**, a Pennsylvania corporation, with offices at 33 Austin Street, Wellsboro, Pennsylvania, (hereinafter referred to as "C&T") and **WELLSBORO ELECTRIC COMPANY** a Pennsylvania public utility corporation, with offices at 33 Austin Street, Wellsboro, Pennsylvania (hereinafter referred to as "Operating Company") (each, individually, "Party" or collectively, "Parties").

WHEREAS, C&T is a public utility holding company organized for the purpose of providing management, communication, financial, technical, operational and other business-related services to its public utilities and others; and

WHEREAS, Operating Company is a for-profit, investor-owned public utility that desires to purchase services from C&T and C&T desires to sell services to Operating Company; and

WHEREAS, Operating Company and C&T are also parties to a general Affiliated Interest Agreement that is filed with the Pennsylvania Public Utility Commission among Operating Company, C&T and other entities that are classified as affiliates of Operating Company under the relevant state statutes (the "AIA")[1]; and

WHEREAS, the Parties wish to reduce their agreement to writing.

NOW THEREFORE, in consideration of the foregoing recitals of fact and the mutual benefits and obligations set forth herein, the Parties agree as follows:

1. DESCRIPTION OF SERVICES. The Parties agree to provide to each other the specific services described herein and set forth in the Addenda attached hereto, which Addenda shall be dated, signed by both C&T and Operating Company, marked alphabetically, e.g., Addendum "A," and so forth, and are incorporated by reference herein.

   1.1 PROVISION OF EMPLOYEES. C&T shall provide service to Operating Company through the assignment of individual C&T Employees to perform specific work and other activities for, and as directed by, the Operating Company. Services will be provided by the specific C&T Employees as identified in Addendum B. Such employees will be considered to be assigned to the Operating Company for purposes of the specific work and other activities.

   1.2 PROVISION AND USE OF VEHICLES, SPACE, MATERIALS AND OTHER EQUIPMENT. In addition to the services described in Paragraph 1.1 of this Contract, the Parties may provide to each other certain vehicles, space, materials and other equipment for use. The rates and charges for such vehicles, materials

[1] The Docket Number and date of approval of the most recent AIA will be set forth in Addendum A of this Contract, which will be updated as necessary.

and other equipment provided will be set forth in Addendum C to this Contract. The rates and charges for space will be set forth in Addendum D to this Contract.

1.3 OTHER SERVICES. In addition to the services described in Paragraphs 1.1 and 1.2 of this Contract, the Parties may provide other services of a nature mutually agreed on by C&T and Operating Company. C&T and Operating Company will execute additional Addenda to this Contract describing such services and specifying the rates and charges for the services. Alternatively, C&T and Operating Company may enter into additional contracts or agreements for such services.

2. RATES AND CHARGES. The rates and charges to be paid by each Party for the services provided shall be set forth on the Addenda attached hereto as provided for in Paragraph 1 of this Contract. These rates and charges shall reflect the lower of actual cost or market. Throughout the course and term of this Contract such rates and charges may be adjusted and revised for any calendar quarter period commencing on the first day of each calendar quarter, upon written notice from C&T to Operating Company not less than thirty (30) days in advance of the calendar quarter for which rates are to be changed. Operating Company's failure to notify C&T in writing of objection to the proposed rates and charges revision within thirty (30) days after receipt of proposed price revision shall be considered acceptance of such revision. In the absence of written notice from C&T to Operating Company regarding any revision of charges and rates, the rates and charges then in effect shall continue until notice is given in accordance with the foregoing schedule.

2.1 LABOR & OVERHEAD CHARGES. C&T shall calculate and bill, on a periodic basis, labor and overhead for all Employees assigned to Operating Company. Overhead charges include, but are not limited to, payroll taxes, pension, workers compensation and health insurance contributions. C&T reserves the right to estimate the monthly cost of certain benefits, subject to subsequent reconciliation. As soon as practical, any benefit adjustments will be charged or credited to the Operating Company.

2.2 SHARED SUPPORT SERVICE ALLOCATION. Consistent with the AIA, C&T will calculate and bill Operating Company for shared support services provided by C&T employees that are not assigned to Operating Company. Shared support services will include, but not be limited to, Human Resources, Payroll, Information Technology, Corporate Communications, Call, Center and Key Accounts.

3. BILLING AND PAYMENT. All rates and charges to be paid by Operating Company to C&T for services rendered to Operating Company shall be billed by C&T by invoice with sufficient detail to document and support the rates and charges set forth therein and submitted to Operating Company on or before the 15th day of each month for services rendered by C&T during the preceding month. Any amounts due from C&T to Operating Company shall be netted against the C&T charges on the monthly invoice. Payment of

such invoice shall be made in full by Operating Company to C&T on or before twenty (20) days from the date of receipt of such invoice, and in the event such invoice is not paid in full, the unpaid portion thereof shall, at C&T's option, accrue interest at the rate of one percent (1%) of the unpaid amount per month, with a partial month being counted as a full month.

3.1 ADVANCED PAYMENT. To enable C&T to meet its obligations due during the initial month of this Contract, C&T may continue to retain any Advanced Payment provided pursuant to the prior Contract for Services between the Parties. C&T may refund the Advanced Payment to the Operating Company, at any time before the termination of the Contract. To the extent not previously refunded, Operating Company shall be entitled to return of the Advanced Payment upon termination of this Contract. The amount of any Advanced Payment that remains in C&T's possession shall be set forth in Addendum E to this Contract.

3.2 ACCOUNTING LIABILITIES. In addition to any rates and charges due hereunder, Operating Company may set up a payable to C&T for amounts necessary under generally accepted accounting principles to book liabilities for future payments due, including for FAS 106 and accrued vacation obligations. C&T shall provide to Operating Company a separate invoice once per year indicating the amount of such liabilities for the year based on an actuarial estimate. Any variance between actual amounts paid by C&T during the year and the actuarial estimate provided to Operating Company shall be subject to reconciliation at the end of the year.

4. TERM. The initial term of this Contract for Services shall commence on the date of this Contract and shall continue for three years. This Contract will thereafter automatically renew for successive one-year terms unless terminated by either party by written notice provided at least sixty (60) days prior to the end of any initial or renewal term. Any such termination shall not affect any obligations undertaken or liabilities incurred by either party prior to the date of termination.

5. DESIGNATION OF OPERATING COMPANY OFFICERS. The Board of Directors of Operating Company retains full authority, power and discretion to designate the Officers for the Operating Company. To the extent the Board of the Operating Company designates a C&T Employee as an Officer of the Operating Company, the Parties shall enter into or revise Addendum B and appropriate schedules to assign the employee to the Operating Company.

6. TEMPORARY ASSIGNMENT OF C&T EMPLOYEES. Notwithstanding the categorization of the C&T Employees designated in Addendum B Schedule 1 to this Contract as being assigned to the Operating Company, C&T may, from time to time, request to use such employees to provide services to other entities. Operating Company's monthly compensation to C&T for such employee's services shall be reduced by the applicable percentage of employee's total working hours allocable to work outside Operating Company. Whenever employees assigned to Operating Company are

temporarily assigned to another operating company, their labor, overhead and expenses will be billed based the provisions of Article II, Section A and/or Article III of the AIA.

7. MANAGEMENT OF ASSIGNED C&T EMPLOYEES. Operating Company will have management authority over C&T Employees assigned to Operating Company under this Contract.

8. REQUEST FOR ADDITIONAL SERVICES. Operating Company may request, from time to time, that C&T provide additional services on a temporary or a permanent basis by C&T employees that are not permanently assigned to Operating Company. By way of example, Operating Company may request the placement of full-time staff members with IT experience on-site during a computer system conversion. Any request for additional services must be conveyed to C&T in a timely manner. To the extent such service is desired on a permanent basis, C&T and Operating Company shall mutually agree on addition of or modification to an Addendum to this Contract. If the permanently-assigned or temporarily-assigned C&T Employee is currently assigned to another entity, the Operating Company will pay a percentage of the compensation for said C&T Employee otherwise recoverable from the other entity based on the portion of total monthly working hours allocable to Operating Company or a written agreement between the two Operating Companies. To the extent such assignment is temporary and such C&T Employee is not currently assigned to another entity, C&T and Operating Company will mutually agree on appropriate compensation.

9. OVERSIGHT COMMITTEE. C&T shall form and convene an Oversight Committee to address complaints, problems or grievances that arise under this Contract or similar agreements entered into with other entities. Each such entity, including Operating Company, shall have the opportunity to designate a member of the Oversight Committee. The Oversight Committee will attempt to resolve all complaints, problems and grievances raised by the Operating Company and other represented entities. To the extent the Oversight Committee cannot resolve such issues, the issues will be submitted to a neutral arbitrator, mutually agreed to by Operating Company and C&T, for binding resolution. Such arbitration will be conducted according to the rules of the American Arbitration Association.

10. RELATIONSHIP OF THE PARTIES. The parties hereto understand and agree that C&T is to provide services under this Contract as an independent contractor to the Operating Company and not as an agent, employee, representative, or in any other manner or relationship whatsoever. At all times throughout the term hereof, C&T shall be free to and intends to contract to provide services to others. Except as stated herein nothing in this Contract shall in any way be construed to constitute C&T or any of C&T's agents or employees as the agent, employee or representative of the Operating Company.

11. CONFIDENTIALITY. All information furnished under and pursuant to this Contract shall be held by C&T and Operating Company in strict confidence and shall never be reproduced, revealed or made accessible in whole or in part, in any manner whatsoever, to any other persons unless required by law, applicable regulatory agencies (including the

Pennsylvania Public Utility Commission) or unless the Party first obtains the other Party's express and written consent; provided, however, the Party may reveal to the subject of the information that the other Party is a source of information about the subject and refer same to the Other Party for the purpose of obtaining such information and reviewing it. Any information specifically designated as "Confidential" may be viewed only by the Officers of the Party and only to the extent necessary to perform their designated duties. Each Party shall take reasonable steps to limit the public disclosure of confidential information provided hereunder.

12. INDEMNIFICATION. Operating Company shall hold C&T harmless against all liability or loss and against all claims or actions based on or arising out of damage or injury (including death) to persons or property caused by or sustained in connection with the performance of this contract or by conditions created thereby, or based on any violation of statue or regulation and the defense of any such claims or actions.

13. INSURANCE. C&T shall, at its sole cost and expense, be covered by comprehensive general liability insurance including contractual liability insurance with combined single limits of not less than One Million Dollars ($1,000,000.00), which insurance coverage and limits shall be evidenced by certificates of insurance as requested by the Operating Company and which insurance policies shall name the Operating Company as additional insured thereon.

14. WORKERS COMPENSATION. Any employees assigned to Operating Company hereunder shall at all times remain C&T Employees for workers compensation purposes. C&T will take reasonable actions with respect to such employees, including, but not limited to, retaining an appropriate amount of Workers Compensation Insurance. C&T agrees to indemnify, defend and hold harmless Operating Company for any workers compensation claim asserted by a C&T Employee.

15. HEADINGS. The description headings of the various paragraphs of this Contract are inserted for reference purposes only and do not form a part of this Contract and shall in no way affect meaning or interpretation thereof.

16. ENTIRE AGREEMENT. This Agreement constitutes and contains the entire understanding and agreement of the parties hereto and supersedes any and all prior understandings and agreements, oral or written, by, between and among the parties regarding the subject matter hereof.

17. AMENDMENTS. This Contract and the Addenda incorporated herein shall be modified and/or amended only by writing signed by both parties hereto, and shall not be effective until filed with and approved by any applicable regulatory agencies, including the Pennsylvania Public Utility Commission. The requirement for approval prior to effectiveness shall not apply to periodic changes to Addenda to update information such as the information regarding the AIA set forth in Addendum A and the employees and related costs assigned to Operating Company under Addendum B.

18. AUTHORITY. C&T and Operating Company hereby covenant and agree, each to the other, that their respective signatories have the authority to execute and bind each pursuant to the appropriate actions of the governing bodies of each. C&T also warrants that it has the authority to provide the services contemplated hereunder.

19. NOTICES. Any notices to be delivered under the terms of this Contract shall be sent by U.S. Mail certified, return receipt requested, addressed as follows;

To C&T:

C&T Enterprises, Inc.
33 Austin Street
Wellsboro, PA 16901

To Operating Company:

Wellsboro Electric Company
33 Austin Street
Wellsboro, PA 16901

20. FORCE MAJEURE. C&T shall use diligence to perform its obligations under this Contact, however, in the event that C&T is delayed in or prevented from performing or carrying out its obligations under this Contract by reason of an unforeseeable event or occurrence beyond reasonable control of and without the fault and negligence of C&T, including, but not limited to, acts of God, strike, flood, earthquake, storm, fire, lightning, epidemic, war, riot, civil disturbance, sabotage, acts of public enemy, explosion, change in law or applicable regulation subsequent to the date hereof and action or inaction by any federal, state or local legislative, executive, administrative, or judicial agency or body which, in any of the foregoing cases, by exercise of due foresight C&T could not reasonably have been expected to avoid, C&T shall not be liable to the Operating Company for or on account of any loss, damage, injury or expense resulting from or arising out of such delay or prevention, provided, however, that C&T shall use due diligence to remove the cause or causes thereof. The settlement of strikes and labor disturbances shall be wholly within the discretion of C&T. Economic hardship shall not constitute a Force Majeure under this Contract.

21. REGULATORY OVERSIGHT/APPROVAL. This Contract constitutes a component of the Affiliated Interest Agreement and relationship between C&T and Operating Company that is subject to oversight by the Pennsylvania Public Utility Commission ("PUC"). To the extent the PUC invalidates and/or modifies any portion of this Contract or the Affiliated Interest Agreement, either during an independent review of the agreement or in a proceeding before the Commission, and such action impacts the terms of this Contract, the parties agree to mutually negotiate in good faith modifications to this Contract consistent with the Commission's decision.

22. PRIOR AGREEMENTS. This Contract shall supersede and replace in its entirety the Contract for Services dated March 29, 2002, between the Parties; provided, however, that the Parties shall remain liable for any obligations incurred under the prior Contract for Services.

23. SEVERABILITY. All agreements and covenants contained in this Contract are severable, and in the event any of them are held to be invalid by any competent court, this Contract will be interpreted as if the invalid agreements or covenants were not contained in this Contract.

24. ASSIGNMENT. This Contract may not be assigned, transferred or conveyed in whole or part by either party without the express written permission of the other.

25. CONSTRUCTION. This Contract shall be governed by the laws of the Commonwealth of Pennsylvania.

26. BINDING EFFECTS. The parties hereto covenant and agree that the terms, conditions and provisions of this Contract shall be binding upon themselves, their respective successors, and assigns.

IN WITNESS WHEREOF, the parties have caused this Contract to be executed and delivered as of the day and year first above written.

C&T ENTERPRISES, INC.

BY: Bobby Kilmer

TITLE: Co. Pres. & CEO

WELLSBORO ELECTRIC COMPANY

BY: [signature]

TITLE: President & CEO

INDEX OF ADDENDA AND SCHEDULES
DATED THE 29th DAY OF SEPTEMBER 2023

Addendum A: Information regarding currently-effective Affiliated Interest Agreement among C&T companies

Addendum B: C&T Employees Assigned to Operating Company

Schedule B-1: Specific C&T Employees and Charges

Addendum C: Vehicles, Materials and Other Equipment

Schedule C-1: Specific Covered Items

Addendum D: Space

Schedule D-1: Summary of Leased Space
Schedule D-2: Lease for C&T Office

Addendum E: Outstanding Advanced Payment

WELLSBORO ELECTRIC COMPANY
CONTRACT FOR SERVICES
DATED THE 6TH DAY OF OCTOBER, 2010
ADDENDUM A
(INFORMATION ON CURRENT AFFILIATED INTEREST AGREEMENT AMONG C&T COMPANIES)

The Pennsylvania Public Utility Commission approved the currently effective Affiliated Interest Agreement among the C&T companies on March 29, 2002, at Docket No. G-00020948.

C&T ENTERPRISES, INC.

1/5/12
Date

by: _____
President & CEO

WELLSBORO ELECTRIC COMPANY

1/5/12
Date

by: _____
President & CEO

WELLSBORO ELECTRIC COMPANY
CONTRACT FOR SERVICES
DATED THE 6TH DAY OF OCTOBER, 2010
ADDENDUM B
(EMPLOYEES)

1. DESCRIPTION OF SERVICES.

C&T shall provide to Operating Company the services of the C&T Employees set forth on the attached listing, marked Schedule B-1. For the period during which this Addendum remains effective, the persons listed on Schedule B-1 shall be considered to be assigned to Operating Company. Schedule B-1 may be modified by mutual consent of C&T and Operating Company.

2. RATES AND CHARGES FOR SERVICES.

The rate and charge for services provided by C&T Employees to Operating Company shall be calculated monthly based on C&T's direct monthly costs related to each such employee, including salary, payroll taxes and benefits. The annual charge for each employee will be listed on Schedule B-1, which shall consequently be designated as highly confidential and handled in accordance with the confidentiality provisions in Paragraph 11 of the Contract.

3. EMPLOYEE BONUSES.

The C&T Employees listed on Schedule B-1 may, from time to time, be provided certain bonuses or other performance-based incentives. To the extent such bonuses or incentives are proposed or instituted by C&T, Operating Company shall have the right to refuse, for reasonable reasons and grounds, to compensate C&T for such bonuses or incentives. Operating Company may also request that C&T provide a bonus or other incentive to specific C&T Employees listed on Schedule B-1. Bonuses or incentives shall be passed through to and paid by Operating Company.

C&T ENTERPRISES, INC.

1/5/12
Date

by: _____
President & CEO

WELLSBORO ELECTRIC COMPANY

1/6/12
Date

by: _____
President & CEO

SCHEDULE B-1 TO ADDENDUM B

CONFIDENTIAL

Title	Annual Charge
PRESIDENT & CEO	$ [redacted]
DIRECTOR OF ENGINEERING & OPERATIONS	$ [redacted]
MANAGER OF CUSTOMER SERVICE	$ [redacted]
VP & TREASURER	$ [redacted]
TECHNICAL ASSISTANT	$ [redacted]
EXECUTIVE ASSISTANT/STAFF SPECIALIST	$ [redacted]
CUSTOMER SERVICE REPRESENTATIVE	$ [redacted]
CUSTOMER SERVICE REPRESENTATIVE	$ [redacted]
ACCOUNTING ASSISTANT	$ [redacted]
Total	$ 1,466,651

Rachel R. Hauser

President & CEO
C&T Enterprses, Inc.

Date: 2/12/2025

President & CEO
Wellsboro Electric Company

Date: 2/4/2025

WELLSBORO ELECTRIC COMPANY
CONTRACT FOR SERVICES
DATED THE 6TH DAY OF OCTOBER, 2010
ADDENDUM C
(VEHICLES, MATERIALS AND EQUIPMENT)

4. DESCRIPTION OF SERVICES.

C&T shall provide to Operating Company (or Operating Company shall provide to C&T) the vehicles, materials and other equipment more particularly detailed and set forth on the attached listing, marked Schedule C-1 , which schedule is incorporated herein as though set forth at length. Schedule C-1 may be changed from time to time by mutual agreement of C&T and Operating Company.

2. RATES AND CHARGES FOR SERVICES.

The rates and charges for services set forth in Paragraph 1 hereof shall be calculated monthly based on the monthly fixed and variable costs related to such vehicles, material or equipment.

C&T ENTERPRISES, INC.

1/5/12
Date

by: _____
President & CEO

WELLSBORO ELECTRIC COMPANY

1/5/12
Date

by: _____
President & CEO

SCHEDULE D-1 TO ADDENDUM D
SUMMARY OF SPACE LEASED BETWEEN PARTIES
UPDATED SEPTEMBER 2023

1. **C&T Office Lease:** Wellsboro ("Lessors") shall lease to C&T ("Lessee") approximately 860 square feet of space on the 3rd floor of Wellsboro's primary office building located at 33 Austin Street, Wellsboro, Pennsylvania. The lease is for a term of one (1) year commencing on January 1, 2022, and will renew automatically for successive monthly terms thereafter unless terminated by either party. The monthly rent is Two Hundred Fifty and 00/100 ($250.00) DOLLARS in advance on the first (1st) day of each month for that month's rental. This lease is attached as Schedule D-2.

2. RESERVED.

C&T ENTERPRISES, INC.

9/28/2023
Date

by: _____
President & CEO

WELLSBORO ELECTRIC COMPANY

9/28/2023
Date

by: _____
President & CEO

COMMERCIAL PROPERTY LEASE

This lease is made between **WELLSBORO ELECTRIC COMPANY**, of 33 Austin Street, Wellsboro, Tioga County, Pennsylvania, 16901, herein called "Lessors", and **C&T ENTERPRISES, INC.**, of P.O. Box 551, Lewisburg, Pennsylvania, 17838, herein called the "Lessee".

Lessors hereby offer to lease to Lessee the premises situate in the Borough of Wellsboro, County of Tioga, Commonwealth of Pennsylvania, 33 Austin Street, 3rd Floor, Wellsboro, Tioga County, 16901, upon the following TERMS and CONDITIONS:

SGA 3/25/22 BMF 3/25/2022

1. **USE:** Lessee agrees that he will use and occupy the demised premises as a ~~communication center~~ office space only and for no other purpose without the written consent of the Lessors first had and obtained; nor shall Lessee obstruct or interfere with the rights of other Lessees, or in any other way injure or annoy them nor will the Lessee allow the leased premises, or any part of it, to be occupied by any other person, business or entity, other than the Lessee or Lessee's employees without the written consent of the Lessors endorsed on this Agreement.

2. **TERM:** Lessors demise the office space at 33 Austin Street, 3rd Floor, Wellsboro, Tioga County, Pennsylvania 16901, for a term of one (1) year commencing on January 1, 2022, and terminating on December 31, 2022. After the initial term, this lease shall automatically renew on a month to month basis. Either party may terminate the lease with thirty (30) days' written notice provided to the other party.

3. **RENT:** Monthly rent for the lease term shall be at of $250.00 per month payable in advance on the first (1st) day of each month for that month's rental. All rental payments shall be made to Lessors at the address specified above. Any payment made ten (10) days or later after the due date shall be assessed a ten (10%) percent late fee which will be added to the monthly payment.

4. **ALTERATIONS:** Lessee shall not, without first obtaining the written consent of Lessors, make any alterations, additions, or improvements, in, to or about the premises. Lessors will pay only for materials that they deem necessary. Any alterations, additions or improvements, in, to or about the leased premises shall be made solely at the Lessee's expense, except for repairs to the roof. Further, any alterations, additions, or improvements in, to or about the premises, except movable or attachable office equipment shall be the property of the Lessors, and shall remain upon and be surrendered with the premises, as a part of it, at the termination of this lease, without molestation or injury.

5. **ORDINANCES AND STATUTES:** Lessee shall comply with all statutes, ordinances and requirements of a municipal, state, and federal authorities now in force, or which may hereafter be in force, pertaining to the premises, occasioned by or affecting the use thereof by Lessee.

6. **ASSIGNMENT AND SUBLETTING:** Lessee shall not assign this Lease or sublet any portion of the premises without prior written consent of the Lessors. Any such assignment or

subletting without consent shall be void and, at the option of the Lessors, may terminate this Lease.

7. **UTILITIES:** Lessors agree to provide and be responsible for the payment of the following: electric, gas, water, sewer, and removal of garbage. Lessee shall be solely liable for telephone/FAX/TV and/or cable bills, as they become due.

8. **ENTRY AND INSPECTION:** Lessee shall permit Lessors or Lessors' agents to enter upon the premises at reasonable times and upon reasonable notice, for the purpose of inspecting the same, and will permit Lessors anytime within sixty (60) days prior to the expiration of this Lease, to place upon the premises any usual "To Let" or "For Lease" signs, and permit persons desiring to lease the same to inspect the premises thereafter. It is understood that the Lessors shall have the option and right to enter the leased premises at any time upon activation of the fire alarm system.

9. **INDEMNIFICATION OF LESSORS:** Lessors shall not be liable for any damage or injury to Lessee, or any other person, or to any property, occurring on the demised premises or any part thereof, and Lessee agrees to hold Lessors harmless from any/and all claims for damages, no matter how caused. Further, Lessee agrees to carry liability insurance in the minimum of $1,000000.00 on the demised premises listing the Lessors as a named insured.

10. **EMINENT DOMAIN:** If the premises or any part thereof or any estate therein, or any other part of the building materially affecting Lessee's use of the premises, shall be taken by eminent domain, this lease shall terminate on the date when title vests pursuant to such taking. The rent, and any additional rent, shall be apportioned as of the termination date, and any rent paid for any period beyond that date shall be repaid to Lessee. Lessee shall not be entitled to any part of the award for such taking or any payment in lieu thereof, but Lessee may file a claim for any taking of fixtures and improvements owned by Lessee, and for moving expenses.

11. **DESTRUCTION OF PREMISES:** In the event of partial destruction of the premises during the term hereof, from any cause, Lessors shall forthwith repair the same, provided that such repairs can be made within sixty (60) days under the existing governmental laws and regulations, but such destruction shall not terminate this lease except that Lessee shall be entitled to a proportionate reduction of rent while such repairs are being made, based upon the extent to which the making of such repairs shall interfere with the business of Lessee on the premises. If such repairs cannot be made within the said sixty (60) days, Lessors, at their option, may take the same within a reasonable time, this lease continuing in effect, with the rent proportionately abated as aforementioned, and in the event that Lessors shall not elect to make such repairs which cannot be made within sixty (60) days, this lease may be terminated at the option of either party. In the event that the building in which the demised premises may be situated is destroyed to an extent of not less than one-third (1/3) of the replacement costs thereof, Lessors may elect to terminate this lease whether the demised premises be injured or not. A total destruction of the building in which the premises may be situated shall terminate this lease.

12. **LESSORS' REMEDIES ON DEFAULT:** If Lessee defaults in the payment of rent, or any additional rent, or default in the performance of any of the other covenants or conditions hereof, Lessors may give Lessee notice of such default, and if Lessee does not cure any such

default, and if Lessee does not cure any such default within fifteen (15) days, after the giving of such notice [or if such default is of such a nature that it cannot be completely cured within reasonable diligence and in good faith to cure such default], then Lessors may terminate this lease on not less than ten (10) days' notice to Lessees. On the date specified in such notice the tenn of this lease shall terminate, and Lessees shall then quit and surrender premises to Lessors, but Lessee shall remain liable as hereinafter provided. If this lease shall have been so terminated by Lessors, Lessors may at any time thereafter resume possession of the premises by any lawful means and remove Lessee or other occupants and their effects.

13. **NO WAIVER OF DEFAULT:** No failure to enforce any term shall be deemed a waiver. This agreement shall remain in full force and effect unless and until terminated under and pursuant to the terms of this agreement. The failure of either party to insist upon strict performance of any of the provisions of this agreement shall in no way affect the right of such party thereafter to enforce that provision. The waiver of any breach of any provision hereof shall not be construed as a waiver of any subsequent breach of the same or similar nature, and shall not be construed as a waiver of strict performance of any other obligations.

14. **ATTORNEY'S FEES:** In case suit should be brought for recovery of the premises, or for any sum due hereunder, or because of any act which may arise out of the possession of the premises, by either party, the prevailing party shall be entitled to all costs incurred in connection with such action, including reasonable attorney's fees.

15. **NOTICES:** Any notice which either party may be or is required to give, shall be given by mailing the same, postage prepaid, to the addresses shown below:

LESSEES: 1775 Industrial Blvd.
Lewisburg, Pennsylvania 17837

LESSORS: 33 Austin Street
Wellsboro, Pennsylvania 16901

Or at such other places as may be designated by the parties from time to time.

16. **NOTICE OF DEFECTS:** Lessee shall give to Lessors prompt written notice of any accident to, or any defects in, to, or on the demised premises that may come to its attention.

17. **ASSIGNS AND SUCCESSORS:** This Lease is binding upon and inures to the benefit of the assigns and successors in interest to the parties.

18. **SUBORDINATION:** This Lease is and shall be subordinated to all existing and future liens and encumbrances against the property.

19. **JURISDICTION, VENUE AND CHOICE OF LAW:** This Agreement shall be construed in accordance with the laws of the Commonwealth of Pennsylvania. Furthermore, the parties agree to utilize and submit to the Jurisdiction and Venue of the Court of Common Pleas of Tioga County, Pennsylvania.

20. **ENTIRE AGREEMENT:** The foregoing constitutes the entire agreement between the parties and may be modified only by a writing signed by both parties. The following Exhibits, if any, have been made a part of this lease before the parties' execution hereof:

Signed this 17th day of December 2021

WELLSBORO ELECTRIC COMPANY:

Attest: Melissa D Sullivan

By: Byron Smith Jr (SEAL)

Signed this 17th day of December 2021

C&T ENTERPRISES, INC:

Attest: Annette L Koder

By: [signature] (SEAL)
STEVEN ALLABAUGH CO-CEO

WELLSBORO ELECTRIC COMPANY
CONTRACT FOR SERVICES
DATED THE 6TH DAY OF OCTOBER, 2010
ADDENDUM E
(ADVANCED PAYMENT)

Pursuant to Paragraph 3.1 of the Contract, C&T currently holds an Advanced Payment from Operating Company of $49,000.

C&T ENTERPRISES, INC.

1/5/12
Date

by: _____
President & CEO

WELLSBORO ELECTRIC COMPANY

1/5/12
Date

by: _____
President & CEO

REVISED CONTRACT FOR SERVICES

THIS CONTRACT, made and executed in duplicate this 28th day of October, 2019, by and between **C&T ENTERPRISES, INC.**, a Pennsylvania corporation, with offices at 33 Austin Street, Wellsboro, Pennsylvania, (hereinafter referred to as "C&T") and **VALLEY ENERGY, INC.** a Pennsylvania public utility corporation, with offices at 523 South Keystone Avenue, Sayre, Pennsylvania (hereinafter referred to as "Operating Company") (each, individually, "Party" or collectively, "Parties").

WHEREAS, C&T is a public utility holding company organized for the purpose of providing management, communication, financial, technical, operational and other business-related services to its public utilities and others; and

WHEREAS, Operating Company is a for-profit, investor-owned public utility that desires to purchase services from C&T and C&T desires to sell services to Operating Company; and

WHEREAS, Operating Company and C&T are also parties to a general Affiliated Interest Agreement that is filed with the Pennsylvania Public Utility Commission among Operating Company, C&T and other entities that are classified as affiliates of Operating Company under the relevant state statutes (the "AIA")[1]; and

WHEREAS, the Parties wish to reduce their agreement to writing.

NOW THEREFORE, in consideration of the foregoing recitals of fact and the mutual benefits and obligations set forth herein, the Parties agree as follows:

1. DESCRIPTION OF SERVICES. The Parties agree to provide to each other the specific services described herein and set forth in the Addenda attached hereto, which Addenda shall be dated, signed by both C&T and Operating Company, marked alphabetically, e.g., Addendum "A," and so forth, and are incorporated by reference herein.

   1.1 PROVISION OF EMPLOYEES. C&T shall provide service to Operating Company through the assignment of individual C&T Employees to perform specific work and other activities for, and as directed by, the Operating Company. Services will be provided by the specific C&T Employees as identified in Addendum B. Such employees will be considered to be assigned to the Operating Company for purposes of the specific work and other activities.

   1.2 PROVISION AND USE OF VEHICLES, SPACE, MATERIALS AND OTHER EQUIPMENT. In addition to the services described in Paragraph 1.1 of this Contract, the Parties may provide to each other certain vehicles, space, materials and other equipment for use. The rates and charges for such vehicles, materials

[1] The Docket Number and date of approval of the most recent AIA will be set forth in Addendum A of this Contract, which will be updated as necessary.

and other equipment provided will be set forth in Addendum C to this Contract. The rates and charges for space will be set forth in Addendum D to this Contract.

1.3 OTHER SERVICES. In addition to the services described in Paragraphs 1.1 and 1.2 of this Contract, the Parties may provide other services of a nature mutually agreed on by C&T and Operating Company. C&T and Operating Company will execute additional Addenda to this Contract describing such services and specifying the rates and charges for the services. Alternatively, C&T and Operating Company may enter into additional contracts or agreements for such services.

2. RATES AND CHARGES. The rates and charges to be paid by each Party for the services provided shall be set forth on the Addenda attached hereto as provided for in Paragraph 1 of this Contract. These rates and charges shall reflect the lower of actual cost or market. Throughout the course and term of this Contract such rates and charges may be adjusted and revised for any calendar quarter period commencing on the first day of each calendar quarter, upon written notice from C&T to Operating Company not less than thirty (30) days in advance of the calendar quarter for which rates are to be changed. Operating Company's failure to notify C&T in writing of objection to the proposed rates and charges revision within thirty (30) days after receipt of proposed price revision shall be considered acceptance of such revision. In the absence of written notice from C&T to Operating Company regarding any revision of charges and rates, the rates and charges then in effect shall continue until notice is given in accordance with the foregoing schedule.

2.1 LABOR & OVERHEAD CHARGES. C&T shall calculate and bill, on a periodic basis, labor and overhead for all Employees assigned to Operating Company. Overhead charges include, but are not limited to, payroll taxes, pension, workers compensation and health insurance contributions. C&T reserves the right to estimate the monthly cost of certain benefits, subject to subsequent reconciliation. As soon as practical, any benefit adjustments will be charged or credited to the Operating Company.

2.2 SHARED SUPPORT SERVICE ALLOCATION. Consistent with the AIA, C&T will calculate and bill Operating Company for shared support services provided by C&T employees that are not assigned to Operating Company. Shared support services will include, but not be limited to, Human Resources, Payroll, Information Technology, Corporate Communications, Call, Center and Key Accounts.

3. BILLING AND PAYMENT. All rates and charges to be paid by Operating Company to C&T for services rendered to Operating Company shall be billed by C&T by invoice with sufficient detail to document and support the rates and charges set forth therein and submitted to Operating Company on or before the 15th day of each month for services rendered by C&T during the preceding month. Any amounts due from C&T to Operating Company shall be netted against the C&T charges on the monthly invoice. Payment of

such invoice shall be made in full by Operating Company to C&T on or before twenty (20) days from the date of receipt of such invoice, and in the event such invoice is not paid in full, the unpaid portion thereof shall, at C&T's option, accrue interest at the rate of one percent (1%) of the unpaid amount per month, with a partial month being counted as a full month.

3.1 ADVANCED PAYMENT. To enable C&T to meet its obligations due during the initial month of this Contract, C&T may continue to retain any Advanced Payment provided pursuant to the prior Contract for Services between the Parties. C&T may refund the Advanced Payment to the Operating Company, at any time before the termination of the Contract. To the extent not previously refunded, Operating Company shall be entitled to return of the Advanced Payment upon termination of this Contract. The amount of any Advanced Payment that remains in C&T's possession shall be set forth in Addendum E to this Contract.

3.2 ACCOUNTING LIABILITIES. In addition to any rates and charges due hereunder, Operating Company may set up a payable to C&T for amounts necessary under generally accepted accounting principles to book liabilities for future payments due, including for FAS 106 and accrued vacation obligations. C&T shall provide to Operating Company a separate invoice once per year indicating the amount of such liabilities for the year based on an actuarial estimate. Any variance between actual amounts paid by C&T during the year and the actuarial estimate provided to Operating Company shall be subject to reconciliation at the end of the year.

4. TERM. The initial term of this Contract for Services shall commence on the date of this Contract and shall continue for three years. This Contract will thereafter automatically renew for successive one-year terms unless terminated by either party by written notice provided at least sixty (60) days prior to the end of any initial or renewal term. Any such termination shall not affect any obligations undertaken or liabilities incurred by either party prior to the date of termination.

5. DESIGNATION OF OPERATING COMPANY OFFICERS. The Board of Directors of Operating Company retains full authority, power and discretion to designate the Officers for the Operating Company. To the extent the Board of the Operating Company designates a C&T Employee as an Officer of the Operating Company, the Parties shall enter into or revise Addendum B and appropriate schedules to assign the employee to the Operating Company.

6. TEMPORARY ASSIGNMENT OF C&T EMPLOYEES. Notwithstanding the categorization of the C&T Employees designated in Addendum B Schedule 1 to this Contract as being assigned to the Operating Company, C&T may, from time to time, request to use such employees to provide services to other entities. Operating Company's monthly compensation to C&T for such employee's services shall be reduced by the applicable percentage of employee's total working hours allocable to work outside Operating Company. Whenever employees assigned to Operating Company are

temporarily assigned to another operating company, their labor, overhead and expenses will be billed based the provisions of Article II, Section A and/or Article III of the AIA.

7. MANAGEMENT OF ASSIGNED C&T EMPLOYEES. Operating Company will have management authority over C&T Employees assigned to Operating Company under this Contract.

8. REQUEST FOR ADDITIONAL SERVICES. Operating Company may request, from time to time, that C&T provide additional services on a temporary or a permanent basis by C&T employees that are not permanently assigned to Operating Company. By way of example, Operating Company may request the placement of full-time staff members with IT experience on-site during a computer system conversion. Any request for additional services must be conveyed to C&T in a timely manner. To the extent such service is desired on a permanent basis, C&T and Operating Company shall mutually agree on addition of or modification to an Addendum to this Contract. If the permanently-assigned or temporarily-assigned C&T Employee is currently assigned to another entity, the Operating Company will pay a percentage of the compensation for said C&T Employee otherwise recoverable from the other entity based on the portion of total monthly working hours allocable to Operating Company or a written agreement between the two Operating Companies. To the extent such assignment is temporary and such C&T Employee is not currently assigned to another entity, C&T and Operating Company will mutually agree on appropriate compensation.

9. OVERSIGHT COMMITTEE. C&T shall form and convene an Oversight Committee to address complaints, problems or grievances that arise under this Contract or similar agreements entered into with other entities. Each such entity, including Operating Company, shall have the opportunity to designate a member of the Oversight Committee. The Oversight Committee will attempt to resolve all complaints, problems and grievances raised by the Operating Company and other represented entities. To the extent the Oversight Committee cannot resolve such issues, the issues will be submitted to a neutral arbitrator, mutually agreed to by Operating Company and C&T, for binding resolution. Such arbitration will be conducted according to the rules of the American Arbitration Association.

10. RELATIONSHIP OF THE PARTIES. The parties hereto understand and agree that C&T is to provide services under this Contract as an independent contractor to the Operating Company and not as an agent, employee, representative, or in any other manner or relationship whatsoever. At all times throughout the term hereof, C&T shall be free to and intends to contract to provide services to others. Except as stated herein nothing in this Contract shall in any way be construed to constitute C&T or any of C&T's agents or employees as the agent, employee or representative of the Operating Company.

11. CONFIDENTIALITY. All information furnished under and pursuant to this Contract shall be held by C&T and Operating Company in strict confidence and shall never be reproduced, revealed or made accessible in whole or in part, in any manner whatsoever, to any other persons unless required by law, applicable regulatory agencies (including the

Pennsylvania Public Utility Commission and the New York Public Service Commission) or unless the Party first obtains the other Party's express and written consent; provided, however, the Party may reveal to the subject of the information that the other Party is a source of information about the subject and refer same to the Other Party for the purpose of obtaining such information and reviewing it. Any information specifically designated as "Confidential" may be viewed only by the Officers of the Party and only to the extent necessary to perform their designated duties. Each Party shall take reasonable steps to limit the public disclosure of confidential information provided hereunder.

12. INDEMNIFICATION. Operating Company shall hold C&T harmless against all liability or loss and against all claims or actions based on or arising out of damage or injury (including death) to persons or property caused by or sustained in connection with the performance of this contract or by conditions created thereby, or based on any violation of statue or regulation and the defense of any such claims or actions.

13. INSURANCE. C&T shall, at its sole cost and expense, be covered by comprehensive general liability insurance including contractual liability insurance with combined single limits of not less than One Million Dollars ($1,000,000.00), which insurance coverage and limits shall be evidenced by certificates of insurance as requested by the Operating Company and which insurance policies shall name the Operating Company as additional insured thereon.

14. WORKERS COMPENSATION. Any employees assigned to Operating Company hereunder shall at all times remain C&T Employees for workers compensation purposes. C&T will take reasonable actions with respect to such employees, including, but not limited to, retaining an appropriate amount of Workers Compensation Insurance. C&T agrees to indemnify, defend and hold harmless Operating Company for any workers compensation claim asserted by a C&T Employee.

15. HEADINGS. The description headings of the various paragraphs of this Contract are inserted for reference purposes only and do not form a part of this Contract and shall in no way affect meaning or interpretation thereof.

16. ENTIRE AGREEMENT. This Agreement constitutes and contains the entire understanding and agreement of the parties hereto and supersedes any and all prior understandings and agreements, oral or written, by, between and among the parties regarding the subject matter hereof.

17. AMENDMENTS. This Contract and the Addenda incorporated herein shall be modified and/or amended only by writing signed by both parties hereto, and shall not be effective until filed with and approved by any applicable regulatory agencies, including the Pennsylvania Public Utility Commission. The requirement for approval prior to effectiveness shall not apply to periodic changes to Addenda to update information such as the information regarding the AIA set forth in Addendum A and the employees and related costs assigned to Operating Company under Addendum B.

18. AUTHORITY. C&T and Operating Company hereby covenant and agree, each to the other, that their respective signatories have the authority to execute and bind each pursuant to the appropriate actions of the governing bodies of each. C&T also warrants that it has the authority to provide the services contemplated hereunder.

19. NOTICES. Any notices to be delivered under the terms of this Contract shall be sent by U.S. Mail certified, return receipt requested, addressed as follows;

To C&T:

C&T Enterprises, Inc.
33 Austin Street
Wellsboro, PA 16901

To Operating Company:

Valley Energy, Inc.
523 South Keystone Avenue
Sayre, PA 18840

20. FORCE MAJEURE. C&T shall use diligence to perform its obligations under this Contact, however, in the event that C&T is delayed in or prevented from performing or carrying out its obligations under this Contract by reason of an unforeseeable event or occurrence beyond reasonable control of and without the fault and negligence of C&T, including, but not limited to, acts of God, strike, flood, earthquake, storm, fire, lightning, epidemic, war, riot, civil disturbance, sabotage, acts of public enemy, explosion, change in law or applicable regulation subsequent to the date hereof and action or inaction by any federal, state or local legislative, executive, administrative, or judicial agency or body which, in any of the foregoing cases, by exercise of due foresight C&T could not reasonably have been expected to avoid, C&T shall not be liable to the Operating Company for or on account of any loss, damage, injury or expense resulting from or arising out of such delay or prevention, provided, however, that C&T shall use due diligence to remove the cause or causes thereof. The settlement of strikes and labor disturbances shall be wholly within the discretion of C&T. Economic hardship shall not constitute a Force Majeure under this Contract.

21. REGULATORY OVERSIGHT/APPROVAL. This Contract constitutes a component of the Affiliated Interest Agreement and relationship between C&T and Operating Company that is subject to oversight by the Pennsylvania Public Utility Commission ("PUC") and the New York Public Service Commission ("PSC"). To the extent the PUC or PSC invalidates and/or modifies any portion of this Contract or the Affiliated Interest Agreement, either during an independent review of the agreement or in a proceeding before the Commission, and such action impacts the terms of this Contract, the parties agree to mutually negotiate in good faith modifications to this Contract consistent with the Commission's decision.

22. PRIOR AGREEMENTS. This Contract shall supersede and replace in its entirety the Contract for Services dated March 29, 2002, between the Parties; provided, however, that the Parties shall remain liable for any obligations incurred under the prior Contract for Services.

23. SEVERABILITY. All agreements and covenants contained in this Contract are severable, and in the event any of them are held to be invalid by any competent court, this Contract will be interpreted as if the invalid agreements or covenants were not contained in this Contract.

24. ASSIGNMENT. This Contract may not be assigned, transferred or conveyed in whole or part by either party without the express written permission of the other.

25. CONSTRUCTION. This Contract shall be governed by the laws of the Commonwealth of Pennsylvania.

26. BINDING EFFECTS. The parties hereto covenant and agree that the terms, conditions and provisions of this Contract shall be binding upon themselves, their respective successors, and assigns.

IN WITNESS WHEREOF, the parties have caused this Contract to be executed and delivered as of the day and year first above written.

ATTEST:

Secretary

C&T ENTERPRISES, INC.

BY:

TITLE: Co Pres. & CEO

ATTEST:

Secretary

VALLEY ENERGY, INC.

BY:

TITLE: PRESIDENT & CEO

INDEX OF ADDENDA AND SCHEDULES
DATED THE 28th DAY OF OCTOBER, 2019

Addendum A: Information regarding currently-effective Affiliated Interest Agreement among C&T companies

Addendum B: C&T Employees Assigned to Operating Company

Schedule B-1: Specific C&T Employees and Charges

Addendum C: Vehicles, Materials and Other Equipment

Schedule C-1: Specific Covered Items

Addendum D: Space

Schedule D-1: Summary of Leased Space

Addendum E: Outstanding Advanced Payment

VALLEY ENERGY, INC.
CONTRACT FOR SERVICES
DATED THE 28TH DAY OF OCTOBER, 2019
ADDENDUM A
(INFORMATION ON CURRENT AFFILIATED INTEREST AGREEMENT AMONG C&T COMPANIES)

The Pennsylvania Public Utility Commission approved the currently effective Affiliated Interest Agreement among the C&T companies on July 15, 2019, at Docket No. G-2008-2020732.

C&T ENTERPRISES, INC.

10/21/2019
Date

by: Bobbi J Kilmer
President & CEO

VALLEY ENERGY, INC.

10/28/19
Date

by: S E Rogers
President & CEO

VALLEY ENERGY, INC.
CONTRACT FOR SERVICES
DATED THE 23rd DAY OF OCTOBER, 2019
ADDENDUM B
(EMPLOYEES)

1. DESCRIPTION OF SERVICES.

C&T shall provide to Operating Company the services of the C&T Employees set forth on the attached listing, marked Schedule B-1. For the period during which this Addendum remains effective, the persons listed on Schedule B-1 shall be considered to be assigned to Operating Company. Schedule B-1 may be modified by mutual consent of C&T and Operating Company.

2. RATES AND CHARGES FOR SERVICES.

The rate and charge for services provided by C&T Employees to Operating Company shall be calculated monthly based on C&T's direct monthly costs related to each such employee, including salary, payroll taxes and benefits. The annual charge for each employee will be listed on Schedule B-1, which shall consequently be designated as highly confidential and handled in accordance with the confidentiality provisions in Paragraph 11 of the Contract.

3. EMPLOYEE BONUSES.

The C&T Employees listed on Schedule B-1 may, from time to time, be provided certain bonuses or other performance-based incentives. To the extent such bonuses or incentives are proposed or instituted by C&T, Operating Company shall have the right to refuse, for reasonable reasons and grounds, to compensate C&T for such bonuses or incentives. Operating Company may also request that C&T provide a bonus or other incentive to specific C&T Employees listed on Schedule B-1. Bonuses or incentives shall be passed through to and paid by Operating Company.

C&T ENTERPRISES, INC.

10/21/2019
Date

by: Bobby Akers
President & CEO

VALLEY ENERGY, INC.

10/23/19
Date

by: E. E. Rogers
President & CEO

SCHEDULE 1 TO ADDENDUM A

[redacted]

Title	Annual Charge
PRESIDENT & CEO	$ [redacted]
VP & TREASURER	$ [redacted]
VP OPERATIONS	$ [redacted]
OPERATIONS MANAGER	$ [redacted]
CUSTOMER SERVICE MANAGER	$ [redacted]
GIS ANALYST	$ [redacted]
CORROSION/MEASUREMENT TECHNICIAN	$ [redacted]
SURVEILLANCE TECHNICIAN	$ [redacted]
FIELD SERVICE TECHNICIAN	$ [redacted]
REGULATOR SHOP TECHNICIAN	$ [redacted]
EXECUTIVE ASSISTANT	$ [redacted]
GAS FITTER 2	$ [redacted]
CONSTRUCTION MANAGER	$ [redacted]
TRAINING & COMPLIANCE COORDINATOR	$ [redacted]
OPERATIONS ASSISTANT	$ [redacted]
REGULATOR TECHNICIAN	$ [redacted]
CORROSION/MEASUREMENT TECHNICIAN	$ [redacted]
FIELD SERVICE TECHNICIAN	$ [redacted]
CUSTOMER REPRESENTATIVE	$ [redacted]
FIELD SERVICE TECHNICIAN	$ [redacted]
SURVEILLANCE TECHNICIAN	$ [redacted]
OPERATIONS TECHNICIAN	$ [redacted]
INVENTORY PURCHASING AGENT	$ [redacted]
METER READER/TESTER	$ [redacted]
GAS FITTER 2	$ [redacted]
ACCOUNTING ASSISTANT	$ [redacted]
CUSTOMER REPRESENTATIVE	$ [redacted]
FIELD SERVICE TECHNICIAN	$ [redacted]
CUSTOMER REPRESENTATIVE	$ [redacted]
GAS FITTER 1	$ [redacted]
GAS FITTER 1	$ [redacted]
Total	$ 4,136,934

Rachel R. Hauser
President & CEO
C&T Enterprses, Inc.

Date: 2/12/2025

E E Rogers
President & CEO
Valley Energy, Inc.

Date: 2/12/25

VALLEY ENERGY, INC.
CONTRACT FOR SERVICES
DATED THE 28th DAY OF OCTOBER, 2019
ADDENDUM C
(VEHICLES, MATERIALS AND EQUIPMENT)

1. DESCRIPTION OF SERVICES.

C&T shall provide to Operating Company (or Operating Company shall provide to C&T) the vehicles, materials and other equipment more particularly detailed and set forth on the attached listing, marked Schedule C-1 , which schedule is incorporated herein as though set forth at length. Schedule C-1 may be changed from time to time by mutual agreement of C&T and Operating Company.

2. RATES AND CHARGES FOR SERVICES.

The rates and charges for services set forth in Paragraph 1 hereof shall be calculated monthly based on the monthly fixed and variable costs related to such vehicles, material or equipment.

C&T ENTERPRISES, INC.

10/21/2019
Date

by: Bobby G Kinney
President & CEO

VALLEY ENERGY, INC.

10/28/19
Date

by: E E Boggess
President & CEO

SCHEDULE C-1 TO ADDENDUM C

1. Currently there are no vehicles, material or other equipment being provided by the affiliated companies.

C&T ENTERPRISES, INC.

10/21/2019
Date

by: Bobby Akers
President & CEO

VALLEY ENERGY, INC.

10/28/19
Date

by: E E Rogers
President & CEO

VALLEY ENERGY, INC.
CONTRACT FOR SERVICES
DATED THE 28th DAY OF OCTOBER, 2019
ADDENDUM D
(SPACE)

1. DESCRIPTION OF SERVICES.

C&T shall provide to Operating Company (or Operating Company shall provide to C&T) the space more particularly detailed and set forth on the attached Schedules marked as D-1, D-2, D-3, etc. To the extent a formal lease agreement exists related to certain space, that agreement will also be included as a Schedule to this Addendum.

2. RATES AND CHARGES FOR SERVICES.

The rates and charges for services for space will be negotiated between the Parties.

C&T ENTERPRISES, INC.

10/21/2019
Date

by: Bobby Kilmer
President & CEO

VALLEY ENERGY, INC.

10/28/19
Date

by: E E Rogers
President & CEO

SCHEDULE D-1 TO ADDENDUM D
SUMMARY OF SPACE LEASED BETWEEN PARTIES

1. There currently is no space leased between the Parties.

C&T ENTERPRISES, INC.

10/21/2019
Date

by: Bobby J Kilmer
President & CEO

VALLEY ENERGY, INC.

10/28/19
Date

by: E E Reagan
President & CEO

VALLEY ENERGY, INC.
CONTRACT FOR SERVICES
DATED THE 28th DAY OF OCTOBER, 2019
ADDENDUM E
(ADVANCED PAYMENT)

Pursuant to Paragraph 3.1 of the Contract, C&T currently holds an Advanced Payment from Operating Company of $100,398.47.

C&T ENTERPRISES, INC.

10/21/2019
Date

by: Bobby Gilmore
President & CEO

VALLEY ENERGY, INC.

10/28/19
Date

by: E E Rogers
President & CEO

Wellsboro Electric, Citizens Electric & Valley Energy
Long-Term Debt and Letter of Credit Certificates
As of 12/31/2024

Wellsboro Electric, Inc

Docket No.	Facility No.	Original Amount	12/31/2024 Balance	Issuance Type	Advance Date	Maturity Date
S-00030942	9005001		$ 618,446	LT Fixed Rate	11/26/2003	09/30/2038
S-00030942	9005002		$ 1,902,152	LT Fixed Rate	11/26/2003	09/30/2038
S-00030942	9005003		$ 1,908,479	LT Fixed Rate	11/26/2003	09/30/2038
S-00030942	9005004		$ 979,869	LT Fixed Rate	11/26/2003	09/30/2038
S-00030942	9005006		$ 1,289,656	LT Fixed Rate	11/26/2003	09/30/2038
S-00030942	9005007		$ 321,085	LT Fixed Rate	11/26/2003	09/30/2038
		$ 12,155,017	$ 7,019,687			

Docket No.	Facility No.	Original Amount	12/31/2024 Balance	Issuance Type	Advance Date	Maturity Date
S-00051045	9006002	$ 1,000,000	$ 280,213	LT Fixed Rate	11/01/2006	12/31/2028

Docket No.	Facility No.	Original Amount	12/31/2024 Balance	Issuance Type	Advance Date	Maturity Date
S-00061153	9012001	$ 500,000	$ 207,911	LT Fixed Rate	12/27/2006	09/30/2031
S-00061153	9012002	$ 500,000	$ 210,428	LT Fixed Rate	08/31/2007	09/30/2031
S-00061153	9012003	$ 500,000	$ 197,364	LT Fixed Rate	02/06/2008	09/30/2031
		$ 1,500,000	$ 615,703			

Docket No.	Facility No.	Original Amount	12/31/2024 Balance	Issuance Type	Advance Date	Maturity Date
S-2010-2162071	9015001	$ 1,200,000	$ 675,020	LT Fixed Rate	02/25/2011	12/31/2034

Docket No.	Facility No.	Original Amount	12/31/2024 Balance	Issuance Type	Advance Date	Maturity Date
S-2011-2240234	9016001	$ 1,000,000	$ 587,972	LT Fixed Rate	03/01/2012	06/30/2035
S-2011-2240234	9016002	$ 1,000,000	$ 616,625	LT Fixed Rate	12/29/2014	06/30/2035
		$ 2,000,000	$ 1,204,597			

Docket No.	Facility No.	Original Amount	12/31/2024 Balance	Issuance Type	Advance Date	Maturity Date
S-2016-2581844	9018001	$ 1,000,000	$ 787,765	LT Fixed Rate	5/8/2017	3/31/2042
S-2016-2581844	9018002	$ 1,000,000	$ 828,462	LT Fixed Rate	6/30/2019	12/31/2041
		$ 2,000,000	$ 1,616,228			

Docket No.	Facility No.	Original Amount	12/31/2024 Balance	Issuance Type	Advance Date	Maturity Date
S-2020-3019803	9022001	$ 2,000,000	$ 1,818,139	LT Fixed Rate	9/30/2020	6/30/2050

Wellsboro Electric, Citizens Electric & Valley Energy
Long-Term Debt and Letter of Credit Certificates
As of 12/31/2024

Docket No.	Facility No.	Original Amount	12/31/2024 Balance	Issuance Type	Advance Date	Maturity Date
S-2022-3033413	9023001	$ 3,000,000	$ 2,920,865	LT Fixed Rate	10/31/2022	9/30/2052
S-2022-3033413	9023002	$ 2,000,000	$ 1,961,712	LT Fixed Rate	6/15/2023	3/31/2053
S-2022-3033413	9023003	$ 1,000,000	$ 980,386	LT Fixed Rate	6/30/2023	3/31/2053
		$ 6,000,000	$ 5,862,962			

Docket No.	Facility No.	Original Amount	12/31/2024 Balance	Issuance Type	Advance Date	Maturity Date
S-2024-3050970	9025001	$ 4,000,000	$ 4,000,000	LT Fixed Rate	10/15/2024	12/31/1954

Docket No. S-00030942 not to exceed $12,200,000. The balance outstanding at December 31, 2024 was $7,019,687.
Docket No. S-00051045 not to exceed $1,000,000. The balance outstanding at December 31, 2024 was $280,213.
Docket No. S-00061153 not to exceed $1,500,000. The balance outstanding at December 31, 2024 was $615,703.
Docket No. S-2010-2162071 not to exceed $1,200,000. The balance outstanding at December 31, 2024 was $675,020.
Docket No. S-2011-2240234 not to exceed $2,000,000. The balance outstanding at December 31, 2024 was $1,204,597.
Docket No. S-2016-2581844 not to exceed $2,000,000. The balance outstanding at December 31, 2024 was $1,616,228.
Docket No. S-2020-3019803 not to exceed $2,000,000. The balance outstanding at December 31, 2024 was $1,818,139.
Docket No. S-2022-3033413 not to exceed $6,000,000. The balance outstanding at December 31, 2024 was $5,862,962.
Docket No. S-2024-3050970 not to exceed $5,000,000. The balance oustanding at December 31, 2024 was $4,000,000.

Citizens Electric Company

Docket No.	Facility No.	Original Amount	12/31/2024 Balance	Issuance Type	Advance Date	Maturity Date
S-00990736	9001001		$ 970,459	LT Fixed Rate	02/08/1999	12/31/2033
S-00990736	9001002		$ 980,452	LT Fixed Rate	02/08/1999	12/31/2033
S-00990736	9001003		$ 999,097	LT Fixed Rate	02/08/1999	12/31/2033
S-00990736	9001004		$ 237,284	LT Fixed Rate	02/08/1999	12/31/2033
S-00990736	9001005		$ 967,396	LT Fixed Rate	02/08/1999	12/31/2033
		$ 8,814,700	$ 4,154,687			

Docket No.	Facility No.	Original Amount	12/31/2024 Balance	Issuance Type	Advance Date	Maturity Date
S-00051064	9007001	$ 450,000	$ 18,457	LT Fixed Rate	10/14/2005	06/30/2025
S-00051064	9007002	$ 550,000	$ 22,559	LT Fixed Rate	10/14/2005	06/30/2025
		$ 1,000,000	$ 41,016			

Docket No.	Facility No.	Original Amount	12/31/2024 Balance	Issuance Type	Advance Date	Maturity Date
S-2016-2581804	9020001	$ 1,200,000	$ 945,319	LT Fixed Rate	5/8/2017	3/31/2042
S-2016-2581804	9020002	$ 800,000	$ 662,770	LT Fixed Rate	6/30/2019	12/31/2041
		$ 2,000,000	$ 1,608,089			

Docket No. S-000990736 not to exceed $9,315,200. The balance outstanding at December 31, 2024 was $4,154,687.
Docket No. S-00051064 not to exceed 1,000,000. The balance outstanding at December 31,2024 was $41,0169.
Docket No. S-2016-2581804 not to exceed 2,000,000. The balance outstanding at December 31,2024 was $1,608,089.

Wellsboro Electric, Citizens Electric & Valley Energy
Long-Term Debt and Letter of Credit Certificates
As of 12/31/2024

Valley Energy, Inc.

Docket No.	Facility No.	Original Amount	12/31/2024 Balance	Issuance Type	Advance Date	Maturity Date
S-00020894	9003001		$ 1,211,122	LT Fixed Rate	11/07/2002	03/31/2032
S-00020894	9003002		$ 1,219,567	LT Fixed Rate	11/07/2002	03/31/2032
S-00020894	9003003		$ 1,225,399	LT Fixed Rate	11/07/2002	03/31/2032
S-00020894	9003004		$ 329,782	LT Fixed Rate	11/07/2002	03/31/2032
S-00020894	9003005		$ 847,535	LT Fixed Rate	11/07/2002	03/31/2032
		$ 12,000,000	$ 4,833,404			

Docket No.	Facility No.	Original Amount	12/31/2024 Balance	Issuance Type	Advance Date	Maturity Date
S-2024-3046097	9024001	$ 1,500,000	$ 1,500,000	LT Fixed Rate	12/19/2024	12/31/1954

Docket No. S-00020894 not to exceed $13,000,000. The balance outstanding at December 31, 2024 was $4,833,404.
Docket No. S-2024-3046097 not to exceed $1,500,000. The Balance outstanding at December 31, 2024 was $1,500,000.

Master Letter of Credit Security Certificates

Docket No.	Company	Original Amount	Balance	Issuance Type	Advance Date	Maturity Date
S-00071217	Citizens'	$ 2,333,333.33	Varies	Letter	09/26/2007	10/06/2012
S-00071218	Wellsboro	$ 2,333,333.33	Varies	Letter	09/26/2007	10/06/2012
S-00071219	Valley	$ 2,333,333.34	Varies	Letter	09/26/2007	10/06/2012
		$ 7,000,000.00				

Docket No.	Company	Original Amount	Balance	Issuance Type	Advance Date	Maturity Date
S-2008-2079859	Citizens'	$ 5,000,000.00	Varies	Letter	11/13/2008	10/06/2012
S-2008-2079943	Wellsboro	$ 5,000,000.00	Varies	Letter	11/13/2008	10/06/2012
S-2008-2079949	Valley	$ 5,000,000.00	Varies	Letter	11/13/2008	10/06/2012
		$ 15,000,000.00				

Docket No.	Company	Original Amount	Balance	Issuance Type	Advance Date	Maturity Date
S-2012-2317822	Citizens'	$ 5,000,000.00	Varies	Letter	10/06/2012	10/06/2015
S-2012-2318247	Wellsboro	$ 5,000,000.00	Varies	Letter	10/06/2012	10/06/2015
S-2012-2318254	Valley	$ 5,000,000.00	Varies	Letter	10/06/2012	10/06/2015
		$ 15,000,000.00				

Wellsboro Electric, Citizens Electric & Valley Energy
Long-Term Debt and Letter of Credit Certificates
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Docket No.	Company	Original Amount	Balance	Issuance Type	Advance Date	Maturity Date
	Citizens'	$ 5,000,000.00	Varies	Letter	10/6/2015	10/06/2018
	Wellsboro	$ 5,000,000.00	Varies	Letter	10/6/2015	10/06/2018
	Valley	$ 5,000,000.00	Varies	Letter	10/6/2015	10/06/2018
		$ 15,000,000.00				

Docket No.	Company	Original Amount	Balance	Issuance Type	Advance Date	Maturity Date
	Citizens'	$ 2,333,333.33	Varies	Letter	10/6/2018	10/5/2021
	Wellsboro	$ 2,333,333.33	Varies	Letter	10/6/2018	10/5/2021
	Valley	$ 2,333,333.34	Varies	Letter	10/6/2018	10/5/2021
		$ 7,000,000.00				

Docket No.	Company	Original Amount	Balance	Issuance Type	Advance Date	Maturity Date
	Citizens'	$ 2,333,333.33	Varies	Letter	10/6/2021	10/5/2024
	Wellsboro	$ 2,333,333.33	Varies	Letter	10/6/2021	10/5/2024
	Valley	$ 2,333,333.34	Varies	Letter	10/6/2021	10/5/2024
		$ 7,000,000.00				

Docket No.	Company	Original Amount	Balance	Issuance Type	Advance Date	Maturity Date
	Citizens'	$ 2,333,333.33	Varies	Letter	10/6/2024	10/5/2029
	Wellsboro	$ 2,333,333.33	Varies	Letter	10/6/2024	10/5/2029
	Valley	$ 2,333,333.34	Varies	Letter	10/6/2024	10/5/2029
		$ 7,000,000.00				